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Planning Electric Transmission Lines:

A Review of Recent Regional Transmission Plans

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Prepared for the
Office of Electricity Delivery and Energy Reliability
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All opinions, errors, and omissions remain the responsibility of the author.

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Acronyms

AECI	Associated Electric Cooperative, Inc.
CAISO	California Independent System Operator
CARIS	Congestion Assessment and Resource Integration Study
CEERTS	cost-effective or efficient regional transmission solutions
CPP	Clean Power Plan
DOE	United States Department of Energy
EIPC	Eastern Interconnection Planning Council
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Collaborative
IRP	integrated resource planning
ISO	independent system operator
ISO-NE	Independent System Operator – New England
ITD	incumbent transmission developer
LBNL	Lawrence Berkeley National Laboratory
LSE	load-serving entity
MISO	Midcontinent Independent System Operator
MMWG	Multiregional Modeling Working Group
MTEP	MISO Transmission Expansion Plan
NERC	North American Electric Reliability Corporation
NTTG	Northern Tier Transmission Group
NYISO	New York Independent System Operator
OASIS	Open Access Same-Time Information System
OATT	open access transmission tariff
QER	Quadrennial Energy Review
RPS	renewable portfolio standard
RTEP	Regional Transmission Expansion Plan
RTO	regional transmission operator
SPP	Southwest Power Pool
SCRTP	South Carolina Regional Transmission Planning
SERTP	Southeastern Regional Transmission Planning
SIRPP	Southeast Interregional Participation Process
TEPPC	Transmission Expansion Planning and Policy Committee
WECC	Western Electricity Coordinating Council

Executive Summary

The first Quadrennial Energy Review (QER) recommends that the U.S. Department of Energy (DOE) conduct a national review of transmission plans and assess the barriers and incentives to their implementation.[1] DOE tasked Lawrence Berkeley National Laboratory (LBNL) to prepare two reports to support the agency's response to this recommendation. This report reviews regional transmission plans and regional transmission planning processes that have been directed by Federal Energy Regulatory Commission (FERC) Order Nos. 890[2] and 1000.[3] We focus on the most recent regional transmission plans (those issued in 2015 and through approximately mid-year 2016) and current regional transmission planning processes. A companion report focuses on non-plan-related factors that affect transmission projects.[4, 5]

We focus on regional transmission plans directed by FERC Orders Nos. 890 and 1000 for three reasons: (1) the orders introduced new requirements that public-utility transmission providers in each transmission planning region must now follow, so assessing barriers to plans created under older regimes is no longer directly relevant for devising guidance for the future; (2) a focus of these requirements is principles for selection of projects for regional cost allocation, which is an important prerequisite for development of some projects and hence may represent a barrier (or incentive) to implementation; and (3) due to their selection for regional cost allocation, projects are more likely to become a focus of greater public attention, which again may emerge as a barrier (or incentive) to implementation.

The importance of FERC Orders No. 890 and 1000 is that they articulate a consistent set of nationwide principles for selecting transmission projects that seek regional or interregional cost allocation. The hallmark of these principles is open, transparent processes through which stakeholder input on regional (and interregional) transmission needs, solutions, and projects is vetted. Seen in this light, elimination of preferences for development of these projects by incumbent transmission owners is an essential feature of FERC's effort to level the playing field for selecting projects to receive regional cost allocation.

The significance of these orders is twofold. First, from the standpoint of FERC Order No. 1000, a principal outcome of regional transmission planning is to determine whether there are transmission solutions that should be selected for regional cost allocation; when a region selects a project for regional (or interregional) cost allocation, this means that the region has concluded that a project is

[1] We have interpreted the recommendation's phrase "implementation of plans" to include all factors affecting regulatory review and construction of a transmission project, both those directly associated with inclusion of projects in a regional transmission plan and those that arise outside of a regional plan or regional transmission planning process. Siting and permitting of transmission projects are well-known examples of factors relevant to transmission planning and expansion over which states have longstanding authority.

[2] See http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

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

[4] Eto, J. 2016. *Building Electric Transmission Lines:* A *Review of Recent Transmission Projects*. LBNL- 1006330.

[5] This report uses "transmission projects" to encompass what others may describe as "transmission facilities."

more efficient or cost-effective than sub-regional (or regional) alternatives. Second, the resulting regional (or interregional) cost allocation, itself, is expected to ensure that the region-wide (or inter-region-wide) costs are allocated roughly commensurate with estimated benefits.

While transmission providers and regions have always evaluated projects that address reliability criteria, and a number of regions have evaluated projects that address economic impacts, FERC Order No. 1000 formally introduced a new consideration that projects may address: transmission needs that are driven by public policy—i.e., by state or federal laws or regulations.[6] Finally, Order No. 1000 also directed formal coordination on transmission planning among regions.

Two basic types of public utility transmission providers[7] are developing regional transmission plans in compliance with FERC Order Nos. 890 and 1000: (1) transmission providers in regions of the country served by vertically integrated utilities that had previously engaged in regional transmission planning on a bi- or multi-lateral basis, and (2) independent system operators and regional transmission operators (ISO/RTO) that had conducted forms of coordinated region-wide planning prior to these FERC orders.

In the regions served by vertically integrated utilities, the combined local plans of individual transmission providers within the region generally form the baseline against which alternative proposed regional transmission solutions are evaluated by the region. In regions served by ISO/RTOs, the local plans of individual transmission providers may also serve as a starting point, but regional transmission needs (and sometimes also regional transmission solutions) are then identified based on a combination of stakeholder input and analysis by ISO/RTO staff. ISO/RTO regional transmission planning routinely evaluates economic impacts resulting from reduced economic congestion and/or lower production costs. Procedures are just now being implemented for assessing transmission needs driven by public policies and interregional coordination.

Current regional transmission plans are snapshots of processes that are evolving rapidly as regional entities work through and begin to implement the new requirements stemming from FERC Order No. 1000. In one case (as of mid-2016), a final compliance order on interregional coordination has not been issued. Among the regional transmission plans issued in 2015 and through approximately the first half of 2016, the principal focus has been on reliability-driven projects. To date, only a handful of plans identify transmission solutions based on market-efficiency considerations that have initiated (or will initiate) an open process to select a developer whose project would receive regional cost allocation. Only one, so far, is focused on identifying specific, new solutions to meet needs created by public policy.[8] No regional transmission plans have as yet selected a transmission project for interregional cost allocation.

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[6] Note that some regions considered public policy drivers for transmission prior to Order No. 1000.

[7] "Public utility transmission provider" is a formal designation and applies to entities that must file Open Access Transmission Tariffs with FERC.

[8] One region (NYISO) is considering two sets of solutions proposed in response to two public-policy transmission needs.

FERC Order Nos. 890 and 1000 focus primarily on regional transmission projects, which refer specifically to those transmission projects selected in regional transmission plans for purposes of cost allocation. The allocation of these costs, in turn, will follow regional and interregional cost allocation methods that reflect Order No. 1000 cost allocation principles. Regional transmission plans may (or may not) include other types of transmission projects, some of which may address regional needs, yet which are not selected for regional cost allocation. Selection of a project for regional cost allocation requires a finding that the project is more efficient or cost-effective than alternatives.

Finding 1: *It will be some time before the outcomes of FERC Order Nos. 890 and 1000 can be fully assessed.*

We believe it is premature to draw conclusions regarding the implementation of FERC Order Nos. 890 and 1000 at this time; therefore, it is also premature to identify specific barriers and incentives to the implementation of projects selected for regional cost allocation in the planning processes that have been conducted pursuant to these orders. Although some regions might have been using project selection processes that to varying degrees were later deemed compliant with the orders, final compliance orders have also directed material changes to these processes. Only regional transmission planning processes executed subsequent to final compliance orders should be considered in assessing the impact of the orders.

Finding 2: *Assessment of FERC Order Nos. 890 and 1000 should be based on information describing the outcomes of regional transmission planning processes, as well as costs (broadly defined) incurred by the processes that achieved these outcomes.*

At this time, activities should be directed toward creating a sound record upon which to assess the regions' progress in implementing FERC's requirements for selection of more efficient or cost effective regional alternatives (see Table ES - 1). From a public policy perspective, the focus should be on monitoring and tracking specific activities that might support future modifications to FERC's orders. FERC Order Nos. 890 and 1000 are an example of an initial order that lays groundwork and a subsequent order that extends the effects of the first order; that is, FERC issued Order No. 890 in 2007, and then, a number of years later, Order No. 1000, which built on and extended aspects of Order No. 890.

Projects that are selected for regional cost allocation are an obvious measure to track as an outcome of regional planning processes, but they are not the only outcome, and they may not be the most important outcome to track. Regions can and will legitimately conclude that there are no regional (or interregional) needs for transmission projects whose costs should be allocated regionally.

Table ES - 1. Regional Transmission Planning Outcomes and Process Elements That Should be Monitored

Planning Outcomes	
Projects selected for regional cost allocation Projects proposed but not selected for regional cost allocation Projects not proposed for regional cost allocation but evaluated as alternatives to project that were proposed yet not selected for regional cost allocation	For all planning outcomes: • Physical characteristics of projects • Project type (reliability, economic, public policy, regional, interregional) • Developer type (incumbent/non-incumbent) • How selection criteria were (or were not) satisfied • Project costs – proposed (actual, if appropriate)
Planning Processes	
Economic and related benefits	• Benefits considered/evaluation methods (e.g., use of production-cost modeling tools) • Consistency of modeling assumptions with other planning activities, including sub-regional and interregional activities (also applies to reliability analysis) • Treatment of uncertainty
Process-related costs	• Project selection process steps/staffing requirements/ schedule • Number of/time commitments for stakeholder workshops/ meetings

Source: Lawrence Berkeley National Laboratory

Finding 3: *The range of transmission benefits considered varies widely in regional transmission planning processes, as does the means by which benefits are evaluated. Moreover, the consideration of transmission benefits is an evolving practice among regional transmission planning entities.*

A region's finding that a project is more efficient or cost-effective than alternatives hinges critically on the definition and scope of the benefits that were considered. All other things being equal, widening the range of benefits considered may result in a project being found more efficient or cost effective and that it may have more benefits to be distributed among beneficiaries. Hence, widening the range of benefits considered might result in more projects being selected for regional cost allocation. Broadening awareness of and demonstrating the importance of considering additional benefits is essential for building stakeholder confidence and support.

There is wide variation among current practices. On the one hand, the benefits considered by each region represent the region's acceptance of the scope of and means by which benefits are currently being taken into account. On the other hand, the variations among practices in different regions suggest that there may be opportunities for evolution or growth in the scope of benefits that are considered by one region based on the experiences of other regions or through the introduction (and acceptance by stakeholders) of other forms of benefits or means for evaluating them. Transmission needs created by public policies are an example. Though meeting transmission needs that public policies create is not a benefit in a direct economic sense, it is a factor that can be used to justify selection of projects for regional cost allocation. In a very simplified sense, if all other things are equal, broadening the range of public-policy needs considered could, in principle, lead to selection of more projects for regional cost allocation.

Finding 4: *There is emerging evidence on and growing sophistication in evaluating transmission benefits that have not yet been considered formally in regional transmission planning processes.*

The literature is growing on benefits of transmission other than those that can be readily assessed with production-cost modeling tools, no matter how sophisticated those tools are. These benefits include those associated with the option value created by transmission as a hedge against future contingencies.[9] ISO/RTOs are beginning to consider some of these issues. [10] These efforts should be encouraged, and their merits and usefulness discussed critically by the regions and stakeholders involved in those regional transmission planning processes. Due consideration must be paid to the fact that uncertainty is an inescapable element in all assessments of future benefits.

Although advanced analysis techniques are not currently an element of regional transmission planning practices, the academic community has been active in adapting and applying these techniques to transmission-planning questions, and these approaches are emerging in real-world planning environments. Formal recognition of and consistent treatment of uncertainty is a growing focus of these activities.[11] What is important in the short run is not formal adoption of these advanced methods by regional planners, but the insights that these methods may provide to the regions and their stakeholders by complementing production-cost-model-based study methods.

Closing Remarks

FERC Order Nos. 890 and 1000 have significantly changed the manner and form of regional transmission planning by creating an open and transparent transmission planning processes. These processes are a powerful tool that regions can wield to address their own transmission needs as well as needs shared with neighboring regions. Still, the planning process established by these FERC orders is only one of several means by which regional and interregional transmission needs can be met. The effectiveness of the planning processes established by these FERC orders will take time to assess. It is essential to begin establishing the record for this assessment now, to inform timely decisions on whether or how the requirements and processes might be enhanced to ensure that regional needs are met efficiently and cost effectively.

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[9] See, for example, Budhraja, V., et al. 2009. "Improving Electric Resource Planning by Considering the Strategic Benefits of Transmission." The Electricity Journal 22(2), March; and Pfeifenberger, J. and D. Hou. 2012. "Transmission's True Value." Public Utilities Fortnightly. September; and Chang, J., J Pfeifenberger, and J Hagerty. 2013 "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments. WIRES. July.
[10] See Southwest Power Pool. 2016. *The Value of Transmission*. January 2016. https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf
[11] See, for example, Hobbs, B. et al. 2016. "Adaptive Transmission Planning: Implementing a New Paradigm for Managing Economic Risk in Grid Expansion." IEEE Power and Energy Magazine. July/August. DOI 10.1109/MPE.2016.2547280.

1. Introduction

The first Quadrennial Energy Review (QER) recommends that the U.S. Department of Energy (DOE) conduct a national review of transmission plans and assess the barriers and incentives to their implementation.[12] DOE tasked Lawrence Berkeley National Laboratory (LBNL) to prepare two reports to support the agency's response to this recommendation. This report reviews regional transmission plans and regional transmission planning processes that have been directed by Federal Energy Regulatory Commission (FERC) Order Nos. 890[13] and 1000.[14] A companion report focuses on non-plan-related factors that affect transmission projects.[15, 16]

1.1. Scope of this Report

This report focuses on regional transmission plans and transmission planning processes that comply with the requirements of FERC Order Nos. 890 and 1000 (see text box).[17] Attention to the most recent regional transmission plans (those issued in 2015 through approximately mid-year 2016) and current regional transmission planning processes (versus focus on older regional transmission plans or on interconnection-wide, sub-regional, or individual utility transmission plans) is warranted for the following reasons:

1. FERC Order Nos. 890 and 1000 introduced new requirements that public-utility transmission providers[18] in each transmission planning region must now follow, so assessing barriers to plans created under older regimes is no longer directly relevant for devising guidance for them.[19]
2. The requirements focus on the principles for the selection of projects for regional cost allocation, which is an important prerequisite for development of some projects and hence may represent a barrier (or incentive) to implementation. For certain projects, ex-ante, regional cost allocation is an important—and in some cases essential—prerequisite for financing, subsequent regulatory approvals, and construction.
3. Due to their selection for regional cost allocation, projects are more likely to become a focus of greater public attention, which again may emerge as a barrier (or incentive) to implementation.

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12 We have interpreted the recommendation's phrase "implementation of plans" to include all factors affecting regulatory review and construction of a transmission project, both those directly associated with inclusion of projects in a regional transmission plan and those that arise outside of a regional plan or regional transmission planning process. Siting and permitting of transmission projects are well-known examples of factors relevant to transmission planning and expansion over which states have longstanding authority.

13 See http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

14 See http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp.

15 Eto, J. 2016. *Building Electric Transmission Lines: A Review of Recent Transmission Projects*. LBNL-1006330.

16 This report uses "transmission projects" to encompass what others may describe as "transmission facilities."

17 All transmission planning by public utility transmission providers is guided by open access transmission tariff (OATT) filings approved by FERC. Therefore, regional transmission plans may include transmission projects other than those that are the main focus of Order Nos. 890 and 1000 (such as merchant transmission projects, transmission projects associated with generator interconnection, and transmission service requests, among others). For completeness, planning for these projects is described; however, it is not the focus of this review.

18 "Public utility transmission provider" is a formal designation for entities that must file OATTs with FERC.

19 See footnote 1 and Eto (2016), which reviews barriers and incentives for a group of transmission projects that fall outside this narrow definition of plans and planning processes.

FERC Orders Nos. 890 and 1000 Established New Requirements for Regional Transmission Planning

FERC Order No. 890 (issued in 2007) directed transmission providers to follow nine transmission planning principles:

1. *Coordination.* The transmission provider must meet with all of its transmission customers and interconnected neighbors to develop a transmission plan.
2. *Openness.* Planning meetings must be open to all affected parties including, but not limited to, all transmission and interconnection customers, state commissions, and other stakeholders.
3. *Transparency.* The transmission provider is required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its planning.
4. *Information Exchange.* Transmission customers are required to submit information on their projected loads and resources, and the transmission provider must give market participants the opportunity to review and comment on draft transmission plans.
5. *Comparability.* The transmission system plan should meet the specific service requests of transmission customers and otherwise treat similarly situated customers comparably.
6. *Dispute Resolution.* Transmission providers must develop a dispute resolution process.
7. *Regional Participation.* The transmission provider is required to coordinate with interconnected systems to share system plans, ensure that these plans are simultaneously feasible, and identify system enhancements that could relieve significant and recurring transmission congestion.
8. *Economic Planning Studies.* The transmission provider is required to annually prepare studies identifying "significant and recurring" congestion and to post such studies on the open-access same-time information system.
9. *Cost Allocation for New Projects.* Planning processes must address cost allocation for new projects.

FERC Order No. 1000 (issued in 2011) established new requirements for transmission planning:

1. Public utility transmission providers must participate in a regional transmission planning process that satisfies Order No. 890 principles and produces a regional transmission plan.
2. Local and regional transmission planning processes must consider transmission needs driven by public-policy requirements established by local, state, or federal laws or regulations.
3. Public-utility transmission providers in each pair of neighboring transmission planning regions within each interconnection must coordinate to determine whether more efficient or cost-effective transmission solutions are available within each pair of neighboring regions.
4. Each transmission planning region must produce a regional transmission plan reflecting solutions that meet the region's needs more efficiently or cost effectively.
5. Stakeholders and any interested party must have a meaningful opportunity to participate in identifying and evaluating potential solutions to regional transmission needs.

Order No. 1000 also requires each public-utility transmission provider to have a method, or set of methods, for allocating the costs of transmission facilities that are selected in the regional transmission plan for purposes of cost allocation. These cost-allocation methods must be consistent with six regional or interregional cost allocation principles, including that the costs of transmission facilities must be allocated to those within the transmission planning region, as well as between regions, that benefit from those facilities, in a manner that is at least roughly commensurate with estimated benefits. Order No. 1000 also removes any federal right of first refusal for new transmission facilities selected in a regional transmission plan for purposes of cost allocation, subject to some limitations.

We acknowledge that projects that are not selected for regional cost allocation through regional transmission planning processes (i.e., that are not eligible for regional cost allocation) can face similar (as well as different) barriers and incentives as are faced by projects that are selected for regional cost allocation. Merchant transmission projects are notable examples. A merchant transmission project does not seek rate recovery through a regional transmission planning process but instead recovers its costs through agreements negotiated directly with those seeking to use the transmission capacity that the project provides. Thus, the involvement of merchant transmission projects in regional transmission planning processes differs from the involvement of transmission developers who seek rate recovery through these regional processes. Several merchant transmission projects are reviewed in Eto (2016).

Other types of transmission projects are also not the focus of this report. These are generally transmission projects that do not seek regional cost allocation. Section 3 mentions them briefly because they are sometimes included in regional transmission planning processes and plans. Some of these projects are a focus of state-led transmission planning (and cost-recovery) activities.

FERC has recognized twelve planning regions of public-utility transmission providers that together are responsible for regional transmission planning in the continental United States, not including Alaska and the portion of Texas served by the Electric Reliability Council of Texas (ERCOT) (see Figure 1). This review focuses on the plans that these twelve regions issued in 2015 up through approximately mid-2016.

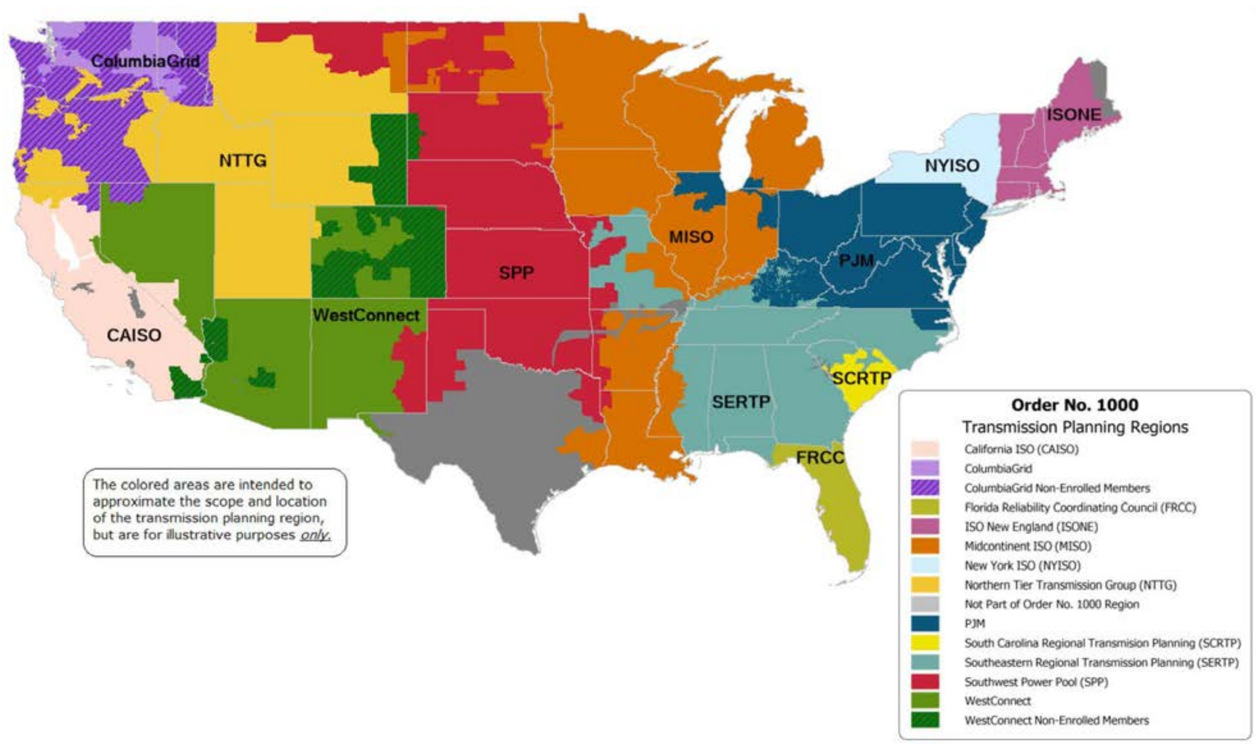

Figure 1. FERC Order 1000 Transmission Planning Regions

Source: FERC. 2016. "Order No. 1000 – Transmission Planning and Cost Allocation." updated March 17, 2016. *http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp*

A major challenge for a review of current regional transmission plans is that regional planning processes are evolving in response to final compliance orders by FERC (see Table 1). For example, the most recent available documents on regional planning procedures describe processes and analysis activities from which the results may not be seen until plans based on them are completed later in 2016 and beyond. At the same time, the regional transmission plans now available for review are based on processes and procedures that in some cases have since been or may soon be modified.

Table 1. Effective Dates and Regional Transmission Planning Cycles

	FERC Regional Order No. 1000 effective date	Regional Transmission Planning Cycle	FERC Interregional Order No. 1000 effective date
California ISO (CAISO)	October 1, 2013	15-month cycle New cycle begins every January (cycles overlap for 3 months)	October 1, 2015 (CAISO, ColumbiaGrid,NTTG, WestConnect)
ColumbiaGrid	January 1, 2015	Two-year cycle New cycle begins January of odd-numbered calendar years	January 1, 2015 (CAISO, ColumbiaGrid, NTTG, WestConnect)
Florida Reliability Coordinating Council (FRCC)	January 1, 2015	Two-year cycle New cycle begins January 2017	January 1, 2015 (FRCC, SERTP)
ISO New England (ISO-NE)	May 18, 2015	No set planning cycle –evaluates transmission needs and transmission projects on an ongoing basis	January 1, 2014 (ISO-NE, NYISO, PJM)
Midcontinent ISO (MISO)	June 1, 2013	18-month cycle New cycle begins each June (cycles overlap for 6 months)	January 1, 2014 (MISO, PJM); March 30, 2014 (MISO, SPP); January 1, 2015 (MISO, SERTP)
New York ISO (NYISO)	January 1, 2014[20]	Two-year cycle Latest cycle began January 2016	January 1, 2014 (NYISO, ISO-NE, PJM)
Northern Tier Transmission Group (NTTG)	October 1, 2013	Two-year cycle Latest cycle began January 2016	October 1, 2015 (CAISO, ColumbiaGrid, NTTG, WestConnect)
PJM (PJM)	January 1, 2014	Two-year cycle Latest cycle began January 2016	January 1, 2014 (PJM, ISO-NE, NYISO); (PJM, MISO); January 1, 2015 (PJM, SERTP)
South Carolina Regional Transmission Planning (SCRTP)	April 19, 2013	Two-year cycle New cycle begins Fall 2016	January 1, 2015 (SCRTP, SERTP)
Southeastern Regional Transmission Planning (SERTP)	June 1, 2014	One-year cycle New cycle begins each January	January 1, 2015 (SERTP, MISO); (SERTP, PJM); (SERTP, FRCC); (SERTP, SCRTP); (SERTP, SPP)
Southwest Power Pool (SPP)	March 30, 2014	Three-year cycle New cycle begins January 2017	March 30, 2014 (SPP, MISO); January 1, 2015 (SPP, SERTP)
WestConnect	January 1, 2015	Two-year cycle Latest cycle began January 2016	October 1, 2015 (CAISO, ColumbiaGrid, NTTG, WestConnect)

Note: As of April 2016, FERC had accepted effective dates for interregional coordination for all region pairs, but a final and substantive compliance order for one interregional pair (MISO, PJM) remained outstanding.

Source: FERC. 2016. "Order No. 1000 – Transmission Planning and Cost Allocation." updated March 17, 2016. http://www.ferc.gov/industries/electric/indus-act/trans-plan.asp

[20] Final Regional Compliance Order is pending at FERC.

This report is based entirely on publicly available information gathered from the twelve regions shown in Figure 1.[21] Each region was given an opportunity to review and comment on the report's factual accuracy.

1.2. Organization of this Report

This report is organized in four sections following this introduction. The first three sections discuss different aspects of regional transmission plans and planning processes.

Section 2 describes the regional transmission planning entities and decision-making processes that lead to the preparation of regional plans. The discussion is organized around origins and missions of the regional planning entities because these elements relate to the entities' regional planning activities, including governance and decision-making processes, significance of selection versus inclusion of projects in a plan, and staffing.

Section 3 describes, in more detail, the processes and procedures by which regional transmission plans are developed. The discussion introduces the different types of transmission projects that may be included in a regional transmission plan. Next, we provide an overview of the planning processes that lead to selection of transmission projects for regional cost allocation following FERC Order Nos. 890 and 1000 (i.e., transmission solutions selected in a regional transmission plan for purposes of cost allocation pursuant to an Order No. 1000-compliant transmission planning process). Finally, we describe aspects of these evaluations and processes in greater detail. These aspects include consideration of economic benefits, transmission needs driven by public policies, and interregional coordination.

Section 4 reviews aspects of recent regional transmission planning outcomes.[22] The discussion is organized around transmission projects that are selected for regional cost allocation, as discussed in Section 3. For several regions, no such outcomes are available to report as yet.[23]

In Section 5, we discuss project-implementation barriers and incentives that can be associated with or linked directly to regional transmission plans and planning processes.[24] In view of the rapidly evolving state of regional practices, we maintain that it is premature to draw definitive conclusions at this time. Consequently, we focus on identifying aspects of regional transmission plans and planning processes that should be tracked and assessed over time to enable future analysis.

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[21] In particular, no effort has been made to include reviews of or references to documents that have been designated as Critical Energy Infrastructure Information (CEII).

[22] The review is based on regional transmission plans published in 2015 up through approximately mid-2016.

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

[24] Eto (2016) reviews selected recent transmission projects, complementing this assessment with a review of barriers and incentives emerging from outside regional transmission plans and planning process (e.g., those related to permitting and siting).

2. The Entities that Prepare Regional Transmission Plans

The twelve regions that prepare regional transmission plans vary considerably in their history and scope of responsibilities. Understanding the differences among the regions is a prerequisite to understanding the types of transmission planning activities that take place in each, the manner in which these activities are conducted, and the outcomes that are documented in each regional transmission plan. This section of the report describes the differences among regions, organized by topic area. The topics we consider are each entity's origins and mission, as well as its governance and decision-making processes; we also consider what "inclusion" and "selection" of projects means in a regional transmission plan, and staffing for development of regional transmission plans.

2.1. Origins and Missions of Entities Responsible for Regional Transmission Planning

FERC Order Nos. 890 and 1000 placed new requirements on public-utility transmission providers that conduct transmission planning in each transmission planning region of the United States. Fulfilling these requirements involves participating in a regional transmission planning process that complies with Order No. 1000 and with the transmission planning principles of Order No. 890, resulting in the development of a regional transmission plan.

In the portions of the country served by ISOs or RTOs, including the California ISO (CAISO), ISO New England (ISO-NE), Midcontinent ISO (MISO), New York ISO (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP), public utility transmission owners had already vested elements of the FERC requirements in these entities. However, FERC Order Nos. 890 and 1000 expanded the transmission planning and cost allocation requirements that these ISOs and RTOs must follow.

In the portions of the country served by vertically integrated utilities, few, if any, such regional planning responsibilities had been vested with a regional entity although vertically integrated utilities in these regions had, in the past, developed joint transmission projects with neighboring utilities. Regions that were formed with these responsibilities as a direct result of Order No. 890 include Northern Tier Transmission Group (NTTG), WestConnect, and South Carolina Regional Transmission Planning (SCRTP). ColumbiaGrid and Southeastern Regional Transmission Planning (SERTP) were formed prior to issuance of Order 890 to conduct coordinated regional planning for their participants.[25] The Florida Reliability Coordinating Council (FRCC) is a NERC regional reliability entity that was utilized for compliance with the orders under its Member Services Division. Order No. 1000 expanded the transmission planning and cost-allocation requirements that public utility transmission providers, which are a part of (or which form) these regional entities, must follow. A number of these regions did not create new legal entities; instead, the responsibilities remain with the individual public-utility transmission providers that participate in a regional planning process.

[25] The number of sponsors in SERTP has varied over time. Currently there are 10 sponsors.

FERC's jurisdiction for regional transmission planning covers all public-utility transmission providers. Some transmission planning regions also include non-public-utility transmission providers (e.g., ColumbiaGrid, NYISO, SERTP, and WestConnect).[26]

The missions of the entities that have regional transmission planning responsibilities vary in scope. Some are independent organizations with multiple missions. For example, the ISO/RTOs also operate organized wholesale markets for electricity. As noted, FRCC serves as the regional reliability entity under the North American Electric Reliability Corporation (NERC). The remaining planning regions have a primary mission of conducting regional transmission planning and preparing regional transmission plans following Order Nos. 890 and 1000. These include ColumbiaGrid, NTTG, SCRTP, SERTP, and WestConnect.

2.2. Governance and Decision-Making Processes by Transmission Planning Regions, including Stakeholder Involvement

The transmission plan developed by each region is approved through a decision-making process, such as a vote by a board of directors. The composition and processes of the decision-making bodies vary, and not all regions have formal decision-making bodies; some regions' decision-making processes are outlined in the project selection procedures in FERC-approved tariffs. The development of a transmission plan is sometimes also subject to review by one or more successively lower-level decision-making bodies that make recommendations about adoption of the plan.

Starting at the highest level of final approval for a regional transmission plan, there are three basic types of decision-making bodies or processes:

- *Boards composed of individuals not affiliated with market participants and who are selected independently by the board.* This is true of most ISO/RTOs. Exceptions are CAISO, whose board is appointed by the state governor, and ColumbiaGrid, which is not an ISO/RTO and has an independent board selected by the members of ColumbiaGrid.
- *Decision-making processes that involve only representatives from the participating public-utility (and, if applicable, non-public-utility) transmission providers in the region.* This is true in two planning regions: SCRTP and SERTP.
- *Boards composed of stakeholders in addition to public-utility (or non-public-utility) transmission providers.* Examples include FRCC, NTTG, and WestConnect. FRCC's board is composed of stakeholders from six sectors: suppliers, non-investor owned utility wholesale, load serving entity, generating load serving entity, investor owned utility, and general. NTTG's board is composed of representatives from the participating public-utility transmission providers, state officials from affected public utility commissions, and state consumer advocate offices. WestConnect's Planning Management Committee is composed of stakeholders organized into

[26] Within the continental United States, the Electric Reliability Council of Texas (ERCOT) is not subject to FERC's transmission planning jurisdiction.

five sectors: transmission owner with load serving obligations, transmission customer, independent transmission developer, state regulatory commission, and key interest group.

Regions that have decision-making bodies have formalized aspects of their voting procedures, including voting rights or weights. These range from approvals based on simple majorities to ones requiring a fixed percentage of assenting votes (e.g., two-thirds or 80% affirmative).[27] Some processes assign explicit voting weights. For example, FRCC's board is composed of six stakeholder sectors; the weight of a sector's vote can vary by as much as a factor of five (i.e., one sector's vote has a collective weight of 2.5; another's has a collective weight of 0.5).[28] Within each sector, voting is divided equally among the number of stakeholders in the sector.

It is important to view features of these decision-making processes—such as board composition, voting procedures, and voting rights—in relation to each region's full scope of responsibilities. Some regions, such as those of the ISO/RTOs, have many functions, including operating transmission grids and energy markets. Thus, their boards have broad scope within which selection of projects for regional cost allocation is only one of many responsibilities. Other regions do not perform such a wide variety of functions and instead focus primarily on transmission planning to comply with Order Nos. 890 and 1000. ColumbiaGrid, SCRTP, SERTP, and WestConnect are examples of such regions. ColumbiaGrid relies on an executive board to make decisions. SCRTP and SERTP rely on sponsors coming to joint agreement on the outcomes of evaluations, which follow project-selection procedures that are outlined in each sponsor's FERC-approved tariffs.

Formal executive decision-making bodies, such as boards, are often supported by standing planning committees (and sometimes subcommittees) that oversee development and recommend adoption of regional transmission plans. This is particularly true of entities, such as many of the ISOs/RTOs, whose scope encompasses other major activities in addition to conducting regional and interregional transmission planning.[29]

Standing committees are composed of stakeholders and supported by the region's planning staff. These committees' approval of the regional transmission plan (which includes selection of projects for regional cost allocation) is often a prerequisite to the executive decision-making body's consideration of the plan for approval. Weighted-sector voting, similar in structure to the weighted voting described above for the FRCC board, is a feature of the decision-making processes of some of these committees.

Instead of relying on standing committees to recommend plan approval to an executive board, some region's plan development and vetting are carried out by the region's staff, and/or the public-utility transmission providers' staff, in a planning process that involves stakeholder participation. This process is similar to vetting performed by standing committee with a planning region's staff; however, at the

[27] There are also variations in quorum requirements, which must be met for voting to take place.
[28] Sector weights are such that no two sectors can carry the motion and no single sector can block a motion. (Personal communication from FRCC, dated September 7, 2016.)
[29] These activities, too, are often supported by separate standing committees of stakeholders.

end of the executive-body process, there is no required formal voting by stakeholders—as there would be through a standing committee—to recommend a regional transmission plan for approval by the executive decision-making body. ColumbiaGrid, SCRTP, and SERTP use this type of process. Some entities, such as PJM, have non-voting advisory committees that review and provide input on stakeholder positions.

Open meetings and, when standing committees are relied on, direct participation in those committees are two principal means by which stakeholders participate in the development of regional transmission plans. Section 3 discusses stakeholder participation in suggesting transmission solutions qualifying for regional cost allocation.

2.3. What does a Project's Selection in a Regional Transmission Plan Mean?

All twelve of the transmission planning regions are required to have a regional cost-allocation method for regional transmission facilities that the transmission plan selects to receive this cost allocation. The regional transmission plan's *selection* of a transmission solution for regional cost allocation means that the transmission-planning process has identified that particular solution as a more efficient or cost-effective solution for regional transmission needs than other alternatives.

Table 2. Summary of MISO Cost Allocation Mechanisms

Allocation Category	Driver(s)	Allocation to Beneficiaries
Participant Funded ("Other")	Transmission owner–identified project that does not qualify for other cost allocation mechanisms; can be driven by reliability, economics, public policy, or some combination of the three	Paid by requestor (local zone[s])
Transmission Delivery Service Project	Transmission service request	Generally paid for by transmission customer; transmission owner can elect to roll-in to local zone rates
Generation Interconnection Project	Interconnection request	Primarily paid for by requestor; 345 kilovolt (kV) and above, 10-percent postage stamp to load
Baseline Reliability Project	NERC reliability criteria	100 percent allocated to local pricing zone
Market Efficiency Project	Reduce market congestion when benefits exceed costs by 1.25 times	Distributed to local resource zones commensurate with expected benefit; 345-kV and above, 20 percent postage stamp to load
Multi-Value Project	Addresses energy policy laws and/or provides widespread benefits across footprint	100 percent postage stamp to load and exports

Note: Only Market Efficiency *and* Multi-Value Projects *qualify for regional cost allocation per FERC Order No. 1000.*

Source: MISO MTEP 2015: *https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP15/MTEP15%20Full%20Report.pdf*

Some regions also have authorities that allocate all or a portion of costs to the region or sub-region depending on project type and beneficiaries. Table 2 is an example of how costs can be allocated for different project types, drawn from MISO's Transmission Expansion Plan 2015 (MTEP15). Note that in

Table 2 only the projects labeled “Market Efficiency” and “Multi-Value” (shown in italics) qualify for regional cost allocation under FERC Order No. 1000. Section 3 will briefly discuss these and other types of transmission projects that may be “included” but have not been “selected” in a regional plan.

As noted, processes used by some regions are designed specifically to implement Order Nos. 890 and 1000 requirements (e.g., FRCC, SCRTP, SERTP, and WestConnect). That is, they have been developed solely or primarily for the purpose of selecting projects for regional cost allocation. Note that, while all regions must have a plan, no region is required to have selected projects for regional cost allocation.

Inclusion of a project in a regional transmission plan may confer determinations in addition to how costs are allocated. For example, in many plans, inclusion of a project (including projects that are selected for regional cost allocation) establishes formal timelines by which milestones toward construction must be met. Failure to meet milestones may be a basis for the transmission planning region to re-evaluate, which could result in removal of a project from a regional plan (including loss of eligibility for regional cost allocation).

No regional transmission planning process has siting or permitting authority. These types of authority fall under the pre-existing jurisdiction of federal, state, and local entities.

2.4. Staffing for Development of Regional Transmission Plans

There are three major approaches to staffing for development of regional transmission plans:

1. A region may rely on a standing body of in-house planning staff (often supplemented by consulting support) to conduct the required modeling and simulation analysis. This is the case in the processes managed by the ISO/RTOs and by ColumbiaGrid.
2. A region may rely on existing in-house staff of the public-utility transmission providers to conduct analyses. This is the case in the processes managed by NTTG, SCRTP, and SERTP.
3. A region may contract out evaluation of a project proposal (e.g., a cost-benefit analysis of a proposed project) to a third party. This approach is used by FRCC and WestConnect.

The last two approaches reflect, in part, bottom-up approaches to transmission planning used by those regions as well as the regions’ comparatively narrower scope of regional planning activities. These regions engage solely in evaluating transmission projects (including reviewing project alternatives) that are being considered for regional cost allocation.

2.5. Summary

The public-utility transmission providers developing regional transmission plans following FERC Order Nos. 890 and 1000 can be grouped into two basic types: First, ISO/RTOs that had conducted forms of coordinated region-wide planning prior to these FERC orders, and, second, transmission providers in regions of the country served by vertically integrated utilities that had previously engaged in regional transmission planning on a bi- or multi-lateral basis. Both rely on or follow one of three basic types of decision-making bodies or processes: (1) Boards composed of individuals not affiliated with market participants and who are selected by the board; (2) Decision-making processes or decisions undertaken solely by representatives from the participating public-utility and non-public-utility transmission providers in the region; and (3) Boards composed of stakeholders other than public-utility (or non-public-utility) transmission providers. For the ISO/RTOs, transmission planning is one of several activities. For regions served by vertically integrated utilities, regional transmission planning consists solely or primarily of evaluations for possible selection of projects for regional cost allocation. No regional transmission planning process has siting or permitting authority; this authority rests with federal, state, and local entities.

Table 3. Regional Transmission Planning Entities

	Origin	Governance for Approval of Regional Plan	Decision making Process	Supporting Committee/ Voting	Significance of Inclusion, Apart From Selection for Eligibility for Regional Cost Allocation	Staffing for Preparation of Plan
California ISO (CAISO)	ISO/RTO	Board of Governors (5), approved by CA Governor	Voting by simple majority	N/A	Determination of need	In house
ColumbiaGrid	Pre-Order 890 (10 parties, including non-jurisdictional utilities)	Independent Board of Directors (3)	Voting by simple majority	N/A	None	In house
Florida Reliability Coordinating Council (FRCC)	Regional reliability entity and Planning Coordinator	Board of Directors (16), organized into 6 sectors (composed of services members)	Voting weighted by sector	Planning Committee; voting weighted by sector	None	In house (supplemented by independent consultants, as needed)
ISO New England (ISO-NE)	ISO/RTO	Independent Board of Directors (10)	Voting by simple majority	Planning Advisory Committee; advisory only	1. Sets baseline costs for comparison to what comes out of siting or changes in scope 2. Creates an obligation for Transmission Owners to construct the project	In house
Midcontinent ISO (MISO)	ISO/RTO	Independent Board of Directors (10)	Voting by simple majority	Planning Advisory Committee; advisory only	Obligation to construct	In house
New York ISO (NYISO)	ISO/RTO	Independent Board of Directors (10)	Voting by simple majority	Management Committee; voting weighted by sector; supermajority required; advisory only	*Unknown - not evident in documents reviewed*	In house
Northern Tier Transmission Group (NTTG)	Order 890 (6 parties)	Steering Committee composed of the 6 utilities, state public utilities commissions (ID, MT, OR, UT, WA, WY), and state consumer advocates (UT and MT)	Voting by 2/3 majority	Planning Committee action requires simple majority from 2 of the 3 member classes; Cost Allocation Committee requires simple majority from each of the 2 member classes	Committed Projects (e.g., those with permits and rights-of-way required for construction) must meet development schedule milestones or may be subject to re-evaluation	Technical Working Group (TWG) consisting of individuals appointed by Planning Committee

	Origin	Governance for Approval of Regional Plan	Decision making Process	Supporting Committee/ Voting	Significance of Inclusion, Apart From Selection for Eligibility for Regional Cost Allocation	Staffing for Preparation of Plan
PJM	ISO/RTO	Independent Board of Managers (10)	Voting by simple majority	Transmission Expansion Advisory Committee (non-voting) provides review and input to PJM on stakeholder positions	Obligation to construct	In house
South Carolina Regional Transmission Planning (SCRTP)	Order 890 (2 parties)	Transmission providers (South Carolina Electric and Gas, and Santee Cooper)	Consensus sought on findings as potential regional projects pass through successive evaluation stages, as outlined in tariff	SCRTP Stakeholder Group provides review and input on stakeholder positions	Contractual agreement between Transmission Provider and Developer	Transmission providers
Southeastern Regional Transmission Planning (SERTP)	Pre-Order 890 (10 parties post Order 1000, including non-jurisdictional utilities)	Transmission providers (10 sponsors, including jurisdictional transmission providers and non-jurisdictional utilities)	Consensus sought on findings as potential regional projects pass through successive evaluation stages, as outlined in tariff	SERTP sponsors coordinate development of the annual regional plan. Stakeholders may provide input throughout the planning process	The regional transmission plans are subject to ongoing evaluation; a project selected for regional cost allocation must also meet specified milestones	SERTP sponsors (jurisdictional Transmission providers and non-jurisdictional utilities)
Southwest Power Pool (SPP)	ISO/RTO	Independent Board of Directors (10)	Voting by simple majority	Markets and Operating Committee (average voting for the two membership sectors must be 2/3)	Inclusion triggers issuance of notifications to construct	In house
WestConnect	Order 890 (18 parties, including non-jurisdictional utilities)	Planning Management Committee (representatives from each participating transmission provider and other members)	Approval by the PMC requires an overall 75% affirmative vote of those members voting, including at least 75% of the TOLSO member sector	Planning Management Committee	Determination of need	Third party

3. Regional Transmission Planning Processes

This section reviews the regions' processes for developing regional transmission plans. We begin by introducing the different types of projects that may be *included* in a regional transmission plan. Next, we focus on planning processes that support the *selection* of regional transmission projects, if any, that qualify for regional cost allocation following FERC Order No. 1000. These include processes that involve selection of project developers; assessment of reliability, economic impacts, and public policies; and, finally, interregional coordination.

3.1. Types of Transmission Projects Included and Not Included in Regional Transmission Plans

Regional transmission plans vary in the types of projects they include. Some plans are limited to transmission projects *selected* for regional cost allocation.[30] Others *include* a broader range of project types that are not eligible for regional cost allocation under FERC Order No. 1000. This subsection of the report introduces nine basic types of transmission projects: the first seven are sometimes included in regional transmission plans, and the final two are generally not included in regional transmission plans. The terminology below can vary among regions. More importantly, the first seven project types do not necessarily all appear in all regional transmission plans. In some regions, these concepts overlap or only exist in a particular regional context.

1. *Generator interconnection projects* enable delivery of a generator's electricity production to the transmission system. These projects are requested by generators. FERC calls these facilities "direct assignment and network upgrade facilities." They are part of a broader category of interconnection facilities. Although these projects are included in all regions' planning studies, whether these projects are included in regional transmission plans varies among regions.
2. *Transmission delivery service projects* satisfy a wholesale transmission customer's request for transmission service. These projects are requested by the customer. FERC also calls these "network upgrades." They are often included in regional transmission plans.
3. *Participant-funded projects*' costs are allocated only to those entities that agree to bear the costs. These projects are sometimes included in regional transmission plans.
4. *Reliability projects* ensure that the transmission system will be operated in compliance with reliability standards. Traditionally, these projects have been proposed by public- (and non-public-) utility transmission providers as additions to the transmission systems that they own. Under FERC Orders 890 and 1000, ISO/RTOs are responsible for planning to meet reliability needs within their regions. Projects are proposed when expectations for future demand growth and/or requests for firm transmission service indicate that reliability standards will be violated

[30] Under FERC Order No. 1000, the term "selected in a regional transmission plan for purposes of cost allocation" excludes a transmission facility if the costs of that facility are participant-funded or borne entirely by the public-utility transmission provider in whose retail distribution service territory or footprint the transmission facility is to be located. See Subsection 3.2.

at some time in the future if prior action is not taken to reinforce the transmission system.[31] Subsection 3.3 of this report describes both how reliability analysis is conducted for projects and how that analysis is supplemented for transmission solutions that may be selected for regional cost allocation.

5. *Economic projects* relieve economic congestion and/or improve the overall economic efficiency of generation dispatch. Planning for projects or project needs that address these economic considerations was initially required under Order No. 890 and is subject to new requirements under Order No. 1000. Subsection 3.4 discusses the procedures that direct how these projects are identified and assessed.

6. *Public-policy projects* address transmission needs driven by federal, state, or local public-policy requirements. This can be a new category of project type or an aspect of other project types that must now be considered as a result of FERC Order No. 1000.[32] Subsection 3.5 discusses the determination of which public policies are considered and how they may affect or drive the need for a transmission solution.

7. *Interregional projects* address the needs of more than one planning region within an interconnection. FERC Order No. 1000 formalized requirements for considering and allocating costs of this category of projects. Subsection 3.6 discusses the identification of these projects and the means by which each region considers them, including how affected regions coordinate their assessments with one another.

In addition, two final types of transmission projects are generally not included in, or are not the focus of, regional transmission plans:

8. *Merchant transmission project* developers are not required to participate in regional planning processes except to provide information on their projects required for interconnection evaluation, or information that may affect assessment of other projects that are included in a regional planning process.[33] Treatment of merchant transmission projects is therefore similar to that for generator interconnection or participant-funded projects.

9. *Transmission projects developed by non-public-utility transmission providers* and that have not voluntarily enrolled in a FERC Order No. 1000 transmission planning region are, by definition, generally not included in regional transmission plans. However, such projects are taken into account in the assessments supporting a regional transmission plan insofar as these projects are (a) known to the participants and staff supporting the regional transmission planning process, and (b) expected to influence the outcomes of these assessments.

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31 For non-RTO planning regions consisting largely of vertically integrated utilities (e.g., SERTP), the majority of transmission projects may consist of reliability projects. This is because, in these regions, the role of the transmission planners is largely to reliably plan the transmission system to integrate the supply-side, demand-side, and load-forecast decisions made by load-serving entities (LSEs) in their often state-regulated integrated resource planning (IRP) processes, as well as to integrate the long-term firm transmission commitments made by third parties.

32 FERC Order No. 1000 requires public-utility transmission providers to consider transmission needs driven by public-policy requirements in the local and regional transmission planning processes, but neither requires nor prohibits the creation of a separate class of public-policy projects.

33 As noted in the introduction, non-plan related aspects of some merchant transmission projects are reviewed in Eto (2016).

3.2. New Planning Requirements Introduced by FERC Order No. 1000

FERC Order No. 1000 introduced new requirements for regional transmission planning processes that alter the traditional roles of transmission plans developed by existing transmission owners. It is important to review these requirements to understand how they have affected the regional transmission planning processes discussed in this section.

Historically, transmission projects were proposed and developed by existing transmission owners mainly within the footprints of their respective retail distribution service territories. Early forms of regional coordination for transmission planning relied on these plans as the starting point for joint or parallel evaluations. Prior to the formation of ISO/RTOs, the existing transmission owners were, in effect, the sole or primary entities responsible for developing projects within their footprints and for coordinating with one another on a bi- or multi-lateral basis to develop projects that involved more than one entity's system.

Following the formation of ISO/RTOs, FERC policies and procedures for regional transmission planning and regional cost allocation began to emerge (e.g., FERC Order No. 890). A focus of these policies was on projects that were deemed to provide regional benefits and whose costs were allocated on a region-wide basis. By and large, however, these projects were proposed only by existing (or incumbent) transmission owners.

FERC Order No. 1000 directed the creation of open processes to allow all qualified project developers to propose transmission solutions that would be eligible for regional cost allocation. In support of this direction, Order No. 1000 defined a new category, "non-incumbent transmission developers," to describe developers that either do not have a retail distribution service territory or footprint or that seek to develop transmission projects outside their existing retail distribution service territory or footprint.[34]

Hence, for projects whose costs would be allocated through a regional cost-allocation method, regional transmission planning must include open and not unduly discriminatory processes that provide both non-incumbent and incumbent transmission developers the opportunity to have their transmission solutions considered and potentially eligible for regional cost allocation. There are, however, exceptions for transmission projects located entirely within the retail distribution service territory or footprint of an incumbent transmission developer.

FERC has begun to characterize the processes relied on by regional transmission planning entities to implement this requirement as broadly following one of two approaches. Under a "sponsorship" approach, incumbent and non-incumbent transmission developers are invited to propose specific transmission projects to solve or address a regional need. The regional transmission planning entity

[34] FERC defines merchant developer and non-incumbent developer as mutually exclusive categories. A merchant developer takes on the financial risk of the project (uses negotiated rates not cost-based rates). A non-incumbent developer does not take on this risk since is entitled to the regional cost allocation for its project if it is selected. The non-incumbent reforms of Order 1000 do not apply to merchant developers.

determines whether any of these proposals is more efficient or cost-effective than alternative proposals. If the finding is affirmative, the project is selected for regional cost allocation and developed by the proposer. A majority of the regional transmission planning regions have been characterized by FERC as relying on this approach. Among the ISO/RTOs, they include ISO-NE, NYISO, and PJM. Importantly, it also includes many of the regions served by vertically integrated utilities (ColumbiaGrid, FRCC, NTTG, SCRTP, and SERTP). For these regions, the aggregation of the individual transmission plans of the individual public (and non-public) utilities forms the basis against which a proposed regional alternative is evaluated.

Under the "competitive solicitation" approach, the transmission planning region identifies regional transmission needs and determines the particular transmission solutions required to meet them. A competitive solicitation process is used to select a developer for each such pre-identified solution. According to FERC, CAISO, MISO, SPP, and WestConnect generally rely on this approach.

3.3. Regional Reliability-Driven Transmission Solutions

Planning evaluations ensure that transmission projects will meet reliability requirements. National, regional, and local reliability standards apply. The primary objectives of these standards are to ensure that load can always be met during periods of normal system operation (resource adequacy) and that the system is capable of returning to secure operation following the occurrence of unplanned, yet credible contingencies—such as the sudden loss of a major generator or transmission element (operational security).[35]

Operational security evaluations rely on a variety of electrical-engineering-software-based simulation tools that assess the expected reliability performance of the transmission system or of a transmission system element under a structured set of hypothetical conditions. Power flow, transient stability, voltage stability, and short-circuit capability are assessed. The assessments focus on expected grid operating conditions during specific times of a study year, such as a summer and winter peak and shoulder conditions, five or ten years in the future. Region-wide load forecasts are the starting point for these assessments.[36, 37]

Although there are some regional differences in how these evaluations are performed,[38] the principal standards upon which they are based are national in scope. Therefore, although the technical details and specific operational assumptions necessarily vary for each regional transmission system, the

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[35] In addition, an objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. Reliability standards allow, in limited circumstances, that Non-Consequential Load Loss may be applied throughout the planning horizon to ensure that Bulk Electric System performance requirements are met. However, when Non-Consequential Load Loss is utilized, in no case can the planned Non-Consequential Load Loss exceed 75 MW for US-registered entities. NERC TPL-001-4.

[36] See NERC Reliability Standard MOD-031-1.

[37] Note, also, that the region-wide load forecast may be either one that is developed independently by the region or one that represents no more than an aggregation of the load forecasts of the entities comprising the region.

[38] See, for example, NESCOE. 2016. *Comparison of Transmission Reliability Planning Studies of the ISO/RTOs in the U.S.*: http://nescoe.com/resources/t-planning-comparison-feb2016/.

structure of the analysis and the criteria for judging acceptable outcomes do not vary greatly by region. The main sources of regional differences in reliability evaluations are in the identification and assessment of regional reliability transmission solutions. As noted earlier, for a project to be selected as a regional reliability transmission solution (and therefore eligible for regional cost allocation), the solution must be determined to be more efficient or cost-effective than competing solutions.

In regions where vertically integrated utilities control operation of all transmission facilities, reliability needs assessments and transmission solutions to address reliability needs are first identified individually by each vertically integrated utility. These solutions, when taken together, form a complete initial set of reliability-related transmission solutions for the region. Potential regional reliability solutions are evaluated, in an open process, in comparison to this initial set of local solutions.

In regions where ISO/RTOs control or direct the operation of transmission facilities, the ISO/RTO generally leads regional reliability needs assessments. The purpose of these assessments is to identify reliability needs that might be met more efficiently or cost effectively through a regional transmission solution rather than through a solution that addresses a local reliability concern.

In some instances, aspects of a regional reliability needs assessment may be shared between the ISO/RTO and the transmission providers. For example, in CAISO's process, transmission providers independently evaluate transmission needs for the facilities over which each transmission provider retains operational control (these are facilities operated at voltages lower than those operated by CAISO). CAISO, in turn, assesses the transmission providers' findings and then incorporates them into a broader, region-wide evaluation. CAISO's planning studies have shown that plans identified by the ISO meet all reliability needs and policy needs, including those related to the use of renewable resources and other preferred resources.

3.4. Economic Analysis of Transmission Solutions

Beginning with FERC Order 890, evaluations of regional transmission solutions must include economic analysis in addition to reliability analysis. In some regions, the goal is to assess the economic impacts of solutions that are identified initially to address reliability needs. In other regions, the goal is to assess the economic impact of solutions proposed with economic benefits as a principal driver. In these regions, the analysis seeks to determine whether the predicted economic benefits warrant moving forward with the transmission solution.[39] Some regions rely on numerical benefit-to-cost ratios in making these assessments.

In ISO/RTO planning regions, production-cost simulation tools are a standard component of the economic analysis of regional transmission solutions. These tools estimate production-cost savings that would result from the increase in transactions that would be enabled by a transmission solution. These analyses rely on forecasts of future demand (both energy and peak) and on expectations regarding the

[39] In many regions, economic issues such as these are also considered outside the regional transmission planning process (e.g., in state-led integrated resource planning (IRP) processes).

composition (and location) of the future generation fleet. All ISO/RTOs lead extensive planning processes with significant stakeholder involvement to develop these inputs, in part because these forecasts are sometimes also the basis or starting point for sub-regional analysis conducted by the incumbent transmission providers within the ISO/RTO footprint.

Assessments of historic, and projections of future, locational marginal prices, which are a feature unique to ISO/RTO markets, are sometimes used in ISO/RTO planning regions to identify areas of economic market congestion and to estimate the economic value of congestion relief that might result from a transmission solution. Some ISO/RTOs (e.g., CAISO and NYISO) prepare studies of these locations and assess the economic value of hypothetical solutions, to guide/elicit market-based solutions to address the congestion in these areas.

Some ISO/RTOs use scenario-based approaches to evaluate economic benefits or include economic considerations beyond those that are normally estimated using production-cost models. For example, MISO's Value-Based Planning approach uses multiple scenarios to assess economic outcomes under more than one set of assumptions regarding future operating conditions. SPP also relies on more than one scenario when analyzing production costs in its Integrated Transmission Planning process. CAISO's Transmission Expansion Assessment Methodology considers transmission's impacts on market prices and allows for use of a lower social discount rate to evaluate the present worth of future benefits.[40]

In vertically integrated regions of the country, production-cost studies to evaluate the economic impacts of potential transmission solutions for inclusion in a regional transmission plan are an emerging practice in three regions: ColumbiaGrid, NTTG, and WestConnect. The remaining regions (FRCC, SCRTP, and SERTP) do not perform production-cost analysis at the regional level. In some cases, they rely instead on similar or related types of economic analyses performed by their load-serving entities (LSEs), which, for example, may conduct these analyses through state PUC-driven integrated resource planning (IRP) processes.

For example, prior to FERC Order No. 1000, economic analysis conducted through the Southeast Interregional Participation Process (SIRPP), whose participants included current sponsors in SCRTP and SERTP, involved identifying the expected cost of transmission solutions to relieve constraints (for each sponsor's region) associated with a series of hypothetical, economically driven power transfers across the region.[41] However, the economic value of these transfers was not assessed. Instead, the purpose of the analysis was to inform stakeholders of the potential regional costs involved in supporting these power transfers, so stakeholders could perform their own analysis of economic value. This process continues annually within SERTP and SCRTP for up to five stakeholder-requested hypothetical, economically driven power transfers across the region.

[40] MISO's Multi-Value Project planning process and PJM's Multi-Driver Planning processes, which are related to enhanced forms of economic analysis, are discussed in Subsection 3.5.

[41] The jurisdictional SERTP sponsors, in concurrence with the other sponsors of SIRPP, proposed to dissolve and otherwise terminate the SIRPP as part of their FERC Order No. 1000 Compliance Filings since the footprint of the SIRPP is now largely subsumed within that of the expanded SERTP.

3.5. Assessments of Transmission Needs that Address Public Policies

FERC Order No. 1000 noted a class of transmission solutions that are often referred to as "public-policy transmission projects." These solutions address transmission needs that are driven by public-policy requirements.

FERC's requirement that planning processes allow for formal consideration of transmission needs driven by public-policy requirements is new.[42] As a result, many current regional transmission plans discuss aspects of selected public policies and describe only supporting analyses that are under way to better inform how transmission solutions might be affected by these public policies in the future. For example, review activities are under way at some ISO/RTOs (e.g., MISO, PJM, and SPP) on the potential impacts of the U.S. Environmental Protection Agency (EPA) Clean Power Plan (CPP) on generation retirements because these retirements would be expected to affect the need for future transmission.

Some regional transmission processes (e.g., FRCC, SCRTP, SERTP) confirm that federal, state, and local laws and regulations are appropriate for consideration and provide means for stakeholders to provide input or propose transmission needs driven by public policy requirements in the region's transmission planning process.[43] Other regional transmission plans explicitly identify particular public-policy requirements that will be taken into account. These are either state renewable portfolio standards (mainly for regional entities in the Western Interconnection) or, as noted above, compliance with the EPA's CPP (mainly for regional entities in the Eastern Interconnection).

FERC Order No. 1000 directs a two-step approach for addressing transmission needs driven by public-policy requirements. First, stakeholders are invited to identify transmission needs that are required to address public-policy requirements. Second, once these needs have been identified, stakeholders are invited to propose solutions to address these needs.

There are regional variations in how the approach is implemented. For example, balancing public-policy considerations or evaluating them in conjunction with other considerations, such as economic ones, is a feature of MISO's Value-Based Planning and PJM's Multi-Driver approaches.

Sometimes, the approach is complemented by a review of transmission solutions that have already been identified either through local or regional reliability analysis (or economic analysis). In these instances the review consists of determining whether current solutions are compatible or consistent with public policy. For example, CAISO conducted a deliverability analysis of currently planned transmission to assess whether additional transmission is required to meet California renewable energy targets given the expected location of future renewable generation facilities.

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[42] Some regional transmission planning processes considered transmission needs driven by public-policy requirements prior to FERC Order No. 1000.

[43] This is because the often state-regulated IRP processes that drive those regions' transmission planning processes already address public-policy requirements.

3.6. Assessments of and Coordination for Interregional Transmission Solutions

A final area of focus in FERC Order No. 1000 is interregional coordination among at least pairs of neighboring regions within each interconnection. Interregional coordination includes ongoing information-sharing activities, and, at times, joint coordinated evaluation of transmission solutions. Similar to treatment of transmission needs that address public policies, this is also a new FERC requirement for regional planning processes.[44] For example, the most recent plans or planning documents from the four western regional planning entities (dating from early through mid-2015) do no more than describe joint meetings at which they have begun to discuss interregional coordination. Each plan points to the joint compliance filing, which was only finalized in June 2015.

Procedurally, interregional transmission solutions must also be proposed as regional solutions by the regions involved. While joint review of these solutions by the regions can proceed in parallel with each regional planning process, as a practical matter, selection of an interregional solution would tend to come after its selection in each individual regional plan. Interregional transmission solutions selected through this process are then eligible for cost allocation in accordance with the interregional cost-allocation principles prescribed by FERC Order 1000.

In short, the majority of regional transmission plans (those available through approximately mid-2016), if they address interregional topics at all, focus only on listing coordination activities related to information sharing, not on evaluation of interregional transmission solutions.

The principal form of explicit interregional coordination that is consistently documented in most current regional transmission plans is interconnection-wide planning activities. In the Western Interconnection, all the regional planning entities rely on the "common case" developed by the Western Electricity Coordinating Council (WECC) Transmission Expansion Planning and Policy Committee (TEPPC) as a starting point for developing 10-year production cost studies. They also rely, to varying degrees, on WECC-developed interconnection-wide power-flow base cases to conduct reliability studies.

In the Eastern Interconnection, many regional planning entities reference the Eastern Reliability Assessment Group's Multiregional Modeling Working Group (MMWG) planning model as a starting point for information on external system conditions for use in conducting reliability studies. Some describe participation in the Eastern Interconnection Planning Collaborative (EIPC).

There are a handful of published interregional coordination activities. The 2013 Northeastern Coordinated System Plan prepared by ISO-NE, NYISO, and PJM is referenced by all three of the participating entities in their most recent plans. But, as noted, this activity predates their compliance filings on interregional coordination, which FERC accepted in November 2015. Currently, these three entities are continuing to exchange modeling information with one another, and they issued the 2015 Northeastern Coordinated System Plan in April 2016. That plan was prepared in accordance with the

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[44] Some regions were engaged in forms of interregional coordination prior to FERC Order No. 1000 (e.g., ISO-NE, NYISO, and PJM; MISO and SPP; and MISO and PJM).

interregional planning principles required by FERC Order 1000. The interregional planning activities performed using the 2014–2015 protocol did not identify any need for new interregional transmission facilities that would be more efficient or cost-effective in meeting the needs of multiple regions than proposed regional system improvements.

Some interregional coordination activities reported in regional plans do not involve interregional transmission solutions. The MISO MTEP15 describes joint analysis of congested paths, which was carried out with PJM. The 2015 SPP Transmission Expansion Plan describes a joint planning activity with Associated Electric Cooperative, Inc. (AECI), which is a non-jurisdictional transmission provider and an enrollee of SERTP.

There are two examples of interregional planning activities that discuss transmission solutions, but, as above, these activities predate FERC approval of final compliance filings.

PJM's 2014 Regional Transmission Expansion Plan (RTEP) describes a production-cost-based analysis, conducted jointly with MISO, involving three scenarios for 75 stakeholder-proposed interregional transmission solutions. PJM and MISO found four solutions that exceeded a 1.25 benefit-cost threshold in at least one scenario that was used to screen solutions for further consideration. PJM subsequently considered only the two solutions emerging from the scenario that were deemed the closest matches to PJM's internal planning assumptions. PJM then found that neither solution met the capital cost size threshold ($20M) on which PJM relies in cross-border planning with MISO. MISO considered all three scenarios and identified two solutions (one in each of the two scenarios not considered by PJM). Neither solution met MISO's regional planning voltage criteria, so these solutions were not considered further.

In 2015, through coordination of MISO's and PJM's regional plans, the two RTOs collaboratively developed the Duff–Rockport–Coleman project to accommodate a reliability need around the Rockport area in PJM. While this project is not an interregional project (and therefore was not selected for interregional cost allocation), it addresses a transmission need that was first identified as interregional.

Late in 2015, MISO and SPP released the Coordinated System Plan Study Report in which they jointly evaluated potential interregional reliability and production-cost economic benefits. The study identified three potential interregional projects. MISO and SPP then separately conducted regional studies to evaluate regional benefits, per their Joint Operating Agreement. None of the three projects was found by both MISO and SPP to be more efficient or cost-effective than regional projects that also addressed these needs.[45]

3.7. Summary

From the standpoint of FERC Order No. 1000, a principal outcome of regional transmission planning is to determine whether there are transmission solutions that should be selected for regional cost allocation. For a transmission project to be selected for regional cost allocation, a region must find that the project is more efficient or cost-effective than alternatives and that the costs of the projects will be allocated roughly commensurate with estimated benefits. FERC Order No. 1000 also introduced a major change in the manner by which a developer for certain types of regional transmission solutions is selected—namely, through a process open to both incumbent and non-incumbent transmission developers. In the regions served by vertically integrated firms, the combined local plans of individual transmission providers within the region generally form a baseline against which alternative proposed regional transmission solutions are evaluated. In areas served by ISO/RTOs, the local plans of individual transmission providers may also serve as a starting point, but regional transmission needs (and sometimes also regional transmission solutions) are then identified based on a combination of stakeholder input and analysis by the staff of the ISO/RTOs. ISO/RTO regional transmission planning routinely evaluates economic impacts resulting from either or both reduced economic congestion and lower production costs. Procedures for assessing transmission needs driven by public policies and interregional coordination are just being implemented.

[45] The MISO regional review found only the Alto-Series Reactor exceeded MISO's benefit-to-cost threshold; however, with evaluation of additional alternatives, it was concluded that a more comprehensive solution was required in that area. The SPP regional review found that both the Southwest Shreveport-Wallace Lake and Elm Creek-NSUB projects provided benefits to SPP greater than their respective costs. However, based on SPP's analysis of the benefits of the Elm Creek-NSUB project, it was determined that since the production cost-related benefits would primarily result from increased coal dispatch, and since the benefits are staged in later years, the project should be evaluated in later studies before being considered for approval. The SPP Board of Directors approved Southwest Shreveport - Wallace Lake as an Interregional Project at the October 2015 Board meeting. However, per the Joint Operating Agreement, because none of the projects was approved by both boards, the projects were deemed rejected as interregional projects.

Table 4. Regional Transmission Planning Processes

	Project Types Included in the Regional Transmission Plan*	Major Elements in the Regional Planning Process Focusing on Project Types that May Be Selected for Regional Cost Allocation	Relationship between Planning by Incumbent Transmission Developers (ITD) within the Regional Footprint and the Regional Planning Process	Selection of Projects for Regional Cost Allocation
California ISO (CAISO)	*Reliability;* *Economic;* *Public policy;* and *Interregional*	In Phase 1, unified planning assumptions, a study plan and a Conceptual Statewide Transmission Plan (which may include projects addressing state, federal policies) are developed. In Phase 2, technical assessments are conducted, and transmission solutions are identified in the Transmission Plan. In Phase 3, developers for identified regional solutions are selected through a competitive process.	ITDs are responsible for planning for facilities that remain under their operational control. These plans can be incorporated by CAISO into the reliability planning phase during which CAISO also considers additional reliability solutions.	Competitive Solicitation - Solicitation process takes place after needs have been established for solutions that would qualify for regional cost allocation.
ColumbiaGrid	Reliability; and *"Order 1000 projects"*	A System Assessment is prepared annually to evaluate whether or not the planned transmission grid can meet established reliability standards. The Biennial Transmission Expansion Plan identifies transmission needs over a 10-year planning horizon. The Biennial Transmission Plan may be updated in even-numbered calendar years.	ITDs' individual plans are included in a joint planning process for a single, integrated system and are evaluated and compared to regional solutions to determine an efficient and cost-effective regional plan.	Sponsorship - Developers propose solutions for identified Order 1000 needs; Study teams evaluate for efficiency and cost-effectiveness relative to existing or other proposed solutions.
Florida Reliability Coordinating Council (FRCC)	Reliability; and *"more cost-effective or efficient regional transmission solutions (CEERTS)"*	The Annual Transmission Planning Process coordinates FRCC members' local plans into a Regional Plan focused on ensuring compliance with reliability standards. The Biennial Transmission Planning Process supplements the annual process, providing a separate process through which more efficient or cost-effective regional transmission solutions may be identified.	ITDs' plans are combined and taken together to establish the basis against which alternatives (CEERTS) are evaluated.	Sponsorship - Regional solutions are nominated by qualified project sponsors and/or project developers and approved by the FRCC Board.
ISO New England (ISO-NE)	Generator interconnection; Elective transmission upgrades; Merchant transmission; *Reliability;*	The process begins with development of a study scope and identification of key inputs to a Needs Assessment, which determines the adequacy of the system to maintain reliability and promote operation of an	ITDs' local plans are evaluated by the ISO as part of reliability needs assessment. The ISO leads the development of reliability solutions with	Sponsorship - Qualified transmission-project sponsors may submit proposals for regional solutions to address identified need for economic,

	Project Types Included in the Regional Transmission Plan*	Major Elements in the Regional Planning Process Focusing on Project Types that May Be Selected for Regional Cost Allocation	Relationship between Planning by Incumbent Transmission Developers (ITD) within the Regional Footprint and the Regional Planning Process	Selection of Projects for Regional Cost Allocation
	Market efficiency; and *Public policy*	efficient wholesale market. A subsequent evaluation of the reliability and cost-effectiveness of potential transmission solutions, including identification of a preferred solution, which, during the cost-allocation process, forms the basis for comparison to the project that is ultimately constructed. The two studies update the ISO's annual Regional System Plan. The biannual Regional System Plan and RSP Project updates summarize the status of projects in all stages of development. Different types of transmission projects and temporal needs are subject to differences in their planning process.	transmission owners for needs that must be addressed less than three years into the future.	public policy, and reliability projects that are needed further than three years in the future. Participating transmission owners build transmission projects identified by the ISO that are needed less than three years in the future for reliability.
Midcontinent ISO (MISO)	Generator Interconnection; Transmission delivery service; Market participant funded; Baseline reliability; Other; *Market efficiency;* and *Multi-value*	An annual process of reliability assessments is conducted in parallel with economic and policy assessments for potential Market Efficiency and Multi-Value projects. All accepted projects are listed in Appendix A of the annual MISO Transmission Expansion Plan (MTEP). MTEP is relied on by subsequent competitive solicitations to select developers for Market Efficiency and Multi-Value projects.	MISO conducts an independent reliability analysis to identify issues. MISO links issues with projects submitted by ITDs from local area planning. MISO identifies gaps and develops solutions as part of its reliability assessment.	Competitive Solicitation - MISO solicits bids for the projects that were approved in MTEP (and identified as competitive).
New York ISO (NYISO)	*Reliability;* *Economic;* *Public policy;* and *Interregional*	A Reliability Needs Assessment triggers solicitations for market-based and regulated solutions. The Comprehensive Reliability Plan reports the evaluation of the proposed solutions, which may include the selection of a transmission solution for cost recovery under NYISO's tariff. This process is complemented by a Congestion Assessment and Resource Integration Study (CARIS). Phase 1 of CARIS adds information on historic and future congestion to identify three study	ITDs' plans for local facilities are included as input to the Reliability Needs Assessment. ITDs' plans for regional facilities (if any) are analyzed as part of the Reliability Needs Assessment.	Sponsorship - For regional solutions, NYISO solicits and then evaluates market-based and regulated responses (from all resources) under a competitive process to meet identified needs (first for reliability, in the CRP, and then for economic assessment, in CARIS Phase 2, and for Public Policy).

	Project Types Included in the Regional Transmission Plan*	Major Elements in the Regional Planning Process Focusing on Project Types that May Be Selected for Regional Cost Allocation	Relationship between Planning by Incumbent Transmission Developers (ITD) within the Regional Footprint and the Regional Planning Process	Selection of Projects for Regional Cost Allocation
		areas for which generic solutions are identified and subjected to cost-benefit analysis and scenario analysis. CARIS Phase 2 evaluates proposed and accelerated Regulated Backstop Projects for eligibility for cost allocation. Final cost allocation is determined through voting by project beneficiaries. The Public Policy Transmission Planning Process begins with a solicitation of needs that is then referred to the NYS Public Service Commission to determine whether a competitive solicitation should be conducted by the NYISO. The NYISO solicits, evaluates, and may select the more efficient or cost effective proposed transmission solution for cost allocation and cost recovery under its tariff.		
Northern Tier Transmission Group (NTTG)	Transmission projects, *"more efficient or cost effective than other options."*	Information collected from stakeholders and members is evaluated for completeness by the Technical Working Group and a Biennial Study Plan is developed for approval by Steering Committee. The Technical Working Group evaluates an Initial Regional Plan including Alternative Projects relative to transmission needs. Following completion of need and reliability analysis to determine the more efficient or cost-effective plan, the Technical Working Group evaluates projects seeking cost allocation and prepares a Draft Final Regional Transmission Plan. The Final Regional Transmission Plan is approved by the Steering Committee.	ITDs project plans, taken together, form the basis for assessments of alternative projects to determine the more efficient or cost-effective regional transmission plan.	Sponsorship –Pre-qualified project sponsors may submit transmission projects and request cost allocation in Q1 of the planning process; Projects selected into the plan from pre-qualified sponsors will be evaluated for regional cost allocation.
PJM	Network projects (identified through System Impact Studies for new generator and merchant transmission	A baseline analysis focused on reliability criteria is conducted on an integrated basis over the entire footprint. This analysis informs Proposal Windows through which	PJM conducts an independent analysis that includes all needs including those to address local area planning needs.	Sponsorship - RTEP opens proposal windows to solicit regional solutions for individual identified needs; Multi-driver

	Project Types Included in the Regional Transmission Plan*	Major Elements in the Regional Planning Process Focusing on Project Types that May Be Selected for Regional Cost Allocation	Relationship between Planning by Incumbent Transmission Developers (ITD) within the Regional Footprint and the Regional Planning Process	Selection of Projects for Regional Cost Allocation
	interconnection, long-term firm transmission service, and upgrade requests); and *Baseline projects* (address operational performance, market efficiency, and reliability criteria) Supplemental projects (transmission owners' identified upgrades to their systems, not driven by PJM reliability or Market Efficiency criteria)	entities offer solutions. A Market Efficiency analysis is also conducted to assess economic benefits if reliability upgrades should be accelerated, or if modifications are warranted to past reliability enhancements to improve market efficiency. In addition, market efficiency analysis is done to develop new transmission to address market efficiency issues. The RTEP encompasses all approved transmission upgrades.	Incumbent Transmission Developers and non-Incumbent Transmission Developers submit proposals to address those needs.	approach provides for identification of more cost-effective solutions to multiple needs.
South Carolina Regional Transmission Planning (SCRTP)	The regional plan includes only *regional transmission projects* selected for regional cost allocation	Each of the two transmission providers conducts an independent local planning process focusing on reliability, economics, and applicable public-policy needs. The transmission providers identify solutions to these needs, which are included in the individual local plans. A regional transmission planning process is conducted in which qualified developers may submit proposals for regional projects (including ones that address reliability, economics, and/or public policy requirements). The transmission providers determine which of these projects are selected for regional cost allocation.	The plans of the two ITDs, taken together, form the basis against which proposed regional alternatives are evaluated.	Sponsorship - Qualified Developers may propose regional solutions in addition to or as alternatives to solutions identified by ITDs in their Local Plans.
Southeastern Regional Transmission Planning (SERTP)	Projects are not "typed"; they meet the relevant need. *To be eligible for regional cost allocation. Certain prerequisites set forth in tariffs must be met.*	The 10 sponsors (i.e., the ITDs) conduct a regional transmission planning process through which the sponsors analyze potential regional alternative transmission projects and qualified developers and stakeholders may submit proposals for alternative projects addressing reliability, economic, and/or public policy requirements.	The plans of each sponsor, taken together, form the basis against which proposed regional alternatives are evaluated.	Sponsorship hybrid - Incumbent and non-incumbent developers may propose regional solutions as alternatives to solutions identified in existing plans.

	Project Types Included in the Regional Transmission Plan*	Major Elements in the Regional Planning Process Focusing on Project Types that May Be Selected for Regional Cost Allocation	Relationship between Planning by Incumbent Transmission Developers (ITD) within the Regional Footprint and the Regional Planning Process	Selection of Projects for Regional Cost Allocation
Southwest Power Pool (SPP)	Transmission service; Generator interconnection; *10-year* and *near-term assessments*; Balanced Portfolio (last approved in 2009); *High priority studies* (last completed in 2014); and Sponsored Upgrade	The SPP Transmission Expansion Plan is a comprehensive listing of all projects over a 20-year planning Horizon. The Integrated Transmission Planning process conducts a 20-year, a 10-year (both performed every three years), and a near-term assessment (performed annually). The 10-year assessment considers two future scenarios. Following completion of the Integrated Transmission Planning Process needs assessment, developers may submit Detailed Project Proposals.	ITDs are principal sources of solutions offered in response to SPP's near-term assessment.	Competitive Solicitation - Competitive Upgrade projects (regional solutions) are solicited through an open process.
WestConnect	*Project selected as the more efficient or cost-effective alternative to an identified regional need.*	WestConnect conducts assessments to determine regional reliability (e.g., violations of reliability criteria in more than one ITD footprint), economic, and public-policy-driven transmission needs.	The local plans of each ITD, taken together, form the basis against which proposed regional alternatives are evaluated.	Competitive Solicitation - Regional solutions are solicited to meet identified regional needs.

**Note: Project types that may be selected for regional cost allocation under FERC Order No. 1000 are in italics.*

Source: See references.

Table 5. Regional Transmission Planning Elements

	Sources for Reliability Planning Criteria	Economic Benefits Evaluation Methods	Sources for/Recent Planning Activities involving Public Polices	Interregional Coordination Activities
California ISO (CAISO)	NERC, WECC	Staff leads an evaluation of up to five high-priority congested study areas to determine whether economic solutions in addition to reliability (and public-policy) projects are warranted; Production Cost and Capacity (Resource Adequacy) savings; 5- and 10-year study cases w/extrapolation to out-years.	Projects evaluated from perspective of compatibility with meeting state renewable portfolio standard requirements	WECC base cases augment local transmission models for reliability assessments. ISO economic planning starts with, but then modifies, the Transmission Expansion Planning Policy Committee (TEPPC) common case.
ColumbiaGrid	NERC, WECC	Economic study process is incorporated into regional planning. Initial production-cost modeling activities are described.	EPA CPP mentioned by stakeholders, but no assessment of EPA CPP is planned until court challenges of EPA CPP have been decided.	WECC base cases form basis, and are augmented, for local transmission models for reliability assessments. Economic planning utilized TEPPC common case information, which is then modified or augmented.
Florida Reliability Coordinating Council (FRCC)	NERC, FRCC	Third-party-led cost-benefit analysis of alternatives proposed by non-incumbent developers. Elements of planned economic analysis are not discussed in detail in documents available for review.	State, federal, local law or regulation mentioned.	MMWG base case augments local transmission models for reliability assessments.
ISO New England (ISO-NE)	NERC, NPCC, Regional and Local reliability criteria	Market efficiency transmission upgrades primarily designed to reduce total net production costs; 10-year present worth period. Stakeholders provide input on transmission costs for projects that are subject to regional costs, especially for projects required within three years.	Regional System Plan 15 discusses relevant recent initiatives.	MMWG base case augments local transmission models for reliability assessments. Joint production-cost databases have been coordinated. Some production-cost studies have been conducted jointly with PJM and NYISO (2013). Reliability studies are coordinated continuously with NYISO and PJM, including studies of generator interconnections, elective transmission upgrades, and regional transmission upgrades. Past studies examined interregional improvements, including tie facilities.

	Sources for Reliability Planning Criteria	Economic Benefits Evaluation Methods	Sources for/Recent Planning Activities involving Public Polices	Interregional Coordination Activities
Midcontinent ISO (MISO)	NERC, Midwest Reliability Organization, Reliability First (RF),SERC, SPP	Multiple future scenarios; 20-year planning horizon.	MTEP15 reviews expected impacts of EPA CPP.	MMWG base case augments local transmission models for reliability assessments. Joint evaluation of congested areas with PJM. Production-cost-based economic analysis of RTO and stakeholder-recommended projects with SPP.
New York ISO (NYISO)	NERC, NPCC, New York State Reliability Council	Production-cost savings over a 10-year study horizon. Additional scenarios and metrics are evaluated for information only.	Established by the New York Public Service Commission.	Joint interregional planning is conducted with PJM and ISO-NE under the Northeast Coordination of Planning Protocol. MMWG base case augments local transmission models for reliability assessments. Joint production-cost studies have been conducted with ISO-NE and PJM (NCSP2013).
Northern Tier Transmission Group (NTTG)	NERC, WECC	Production-cost modeling is conducted over a 10-year study horizon. Change cases including individual alternative projects are evaluated based on changes in capital-related costs, energy losses, and reserves to identify whether a change case is a more efficient or cost-effective solution for the NTTG Footprint than the Initial Regional Plan.	NTTG receives transmission needs driven by Public Policy Requirements, Public Policy Considerations and data from the local transmission plans and stakeholders during Quarter 1. NTTG's Regional Transmission Plan only includes consideration of transmission needs driven by public-policy requirements that are established by state, federal, local law or regulation. Public-policy considerations (those not established by local, state, or federal laws or regulation) are evaluated for consideration as scenario analysis to determine whether they create additional transmission needs.	A proponent of an Interregional Transmission Project (ITP) may seek to have its ITP jointly evaluated by the Relevant Planning Regions (RPR) by submitting the ITP into the regional planning process of each RPR, in accordance with each RPR's regional transmission planning process. For each ITP that has been properly submitted, NTTG will confer with the other RPR's and seek to resolve any differences in planning assumptions and technical data that may affect the evaluation of the ITP in its regional transmission planning process.

	Sources for Reliability Planning Criteria	Economic Benefits Evaluation Methods	Sources for/Recent Planning Activities involving Public Polices	Interregional Coordination Activities
PJM	NERC, RF, SERC	As part of Market Efficiency analysis, production-cost modeling is conducted over a 15-year study horizon to assess extent to which projects mitigate congestion.	Based on State Agreement Approach; Plans for RTEP 2015 describe a planned study (requested by Organization of PJM States, Inc.) of the effects of generation retirements due to EPA's CPP.	MMWG base case augments local transmission models for reliability assessments. Joint production-cost studies have been conducted with ISO-NE and NYISO (2013). Following request from NC Utilities Commission, PJM and NC Transmission Planning Collaborative studied impacts of expected imports from MISO (resulting from PJM auction). Joint economic assessment with MISO has been conducted of stakeholder requested projects.
South Carolina Regional Transmission Planning (SCRTP)	NERC, SERC	10-year study horizon; in 2015, an economic study was conducted of hypothetical transfers across portions of the region. The costs of potential upgrades to address identified constraints were estimated. Currently, stakeholders may request up to 5 economic transfer sensitivity studies (but can request and pay ITDs for the cost of conducting additional studies).	State, federal, local law or regulation mentioned.	MMWG base case augments local transmission models for reliability assessments.
Southeastern Regional Transmission Planning (SERTP)	NERC, SERC	Up to five economic studies may be requested by regional stakeholder groups to examine hypothetical transfers across portions of the region. The studies estimate the economic costs of potential upgrades to address identified constraints.	State, federal, local law or regulation mentioned.	MMWG base case augments local transmission models for reliability assessments. The SERTP creates regional models an interregional data exchange occurs annually with each of the SERTP's neighboring planning regions.
Southwest Power Pool (SPP)	NERC, SPP	A security-constrained economic dispatch and security -constrained unit-commitment-based economic analysis are conducted of congested facilities. Production-cost is modeled over 10- and 15-year horizons.	Incorporated into Integrated Transmission Planning Process.	State, federal, local law or regulation mentioned. Joint reliability and production-cost based analysis has been conducted with MISO. Joint reliability evaluation of selected projects with AECI.

	Sources for Reliability Planning Criteria	Economic Benefits Evaluation Methods	Sources for/Recent Planning Activities involving Public Polices	Interregional Coordination Activities
WestConnect	NERC, WECC	Production-cost study over a 10-year horizon is to be conducted.	Verification of resources needs to meet state renewable portfolio standard requirements included in WestConnect models.	WECC base cases augment local transmission models for reliability assessments. Economic planning starts with TEPPC common case.

4. Recent Regional Transmission Planning Outcomes

This section of the report reviews outcomes from recent regional transmission plans available from 2015 through mid-2016. We focus on projects qualifying for regional cost allocation, especially as required by aspects of FERC Order Nos. 890 and 1000. It should be noted that some regional planning entities had not finalized or did not publish a regional transmission plan during this period.

Among the plans that were available for review, many did not identify new projects that would qualify for regional cost allocation and require an open competitive process to select a project developer (ColumbiaGrid, NTTG,[46] NYISO, SCRTP, SERTP, WestConnect). Some plans do select projects for regional cost allocation, but these were not developed through an open competitive process to select a project developer (e.g., ISO-NE). Three ISO/RTO plans identify transmission solutions that would (or might in the future) qualify for regional cost allocation based on economic considerations (CAISO, MISO, PJM, and SPP). Only CAISO, PJM, and SPP have conducted open solicitations for transmission developers to propose projects that would qualify for regional cost allocation. MISO is currently conducting such a solicitation based on findings in its current plan (MTEP15).

Three entities have reviewed, from the perspective of public-policy needs, transmission solutions that are currently in the planning process: CAISO, NTTG, and WestConnect. None found that additional transmission was required at this time to meet these needs, which stem from state renewable portfolio standards. At the end of October 2015, NYISO solicited solutions to address the Western New York Public Policy Transmission Need identified by the New York State Department of Public Service. In February 2016 a second solicitation was released to address the Transmission Public Policy Transmission Need. NYISO has received and is currently evaluating proposed solutions in response to both solicitations.

During 2015, PJM evaluated 93 market-efficiency proposals submitted as part of the 2014/15 long-term RTEP solicitation window, which was open from October 30, 2014 through February 27, 2015. This led to PJM Board approval in October 2015 of 11 market-efficiency proposals.

As noted in Section 3.6, there are few interregional studies of transmission solutions (only MISO, PJM, and SPP). None of these have, as yet, led to subsequent agreements by both regional planning entities on an interregional transmission solution.

4.1. Summary

Current regional transmission plans are snapshots of rapidly evolving planning processes at each of the regional entities, which are working through and beginning to implement or refine implementation of the new requirements of FERC Order No. 1000. In one instance (as of mid-2016), a final compliance

[46] NTTG published a Regional Transmission Plan for its 2014-2015 regional planning cycle. Two regional projects were selected into the plan. One project is not requesting regional cost allocation, and the other did not meet the requirements for regional cost allocation.

order on interregional coordination has not been issued (MISO-PJM). In the regional transmission plans issued in 2015 and through approximately mid-2016, the principal focus has been on reliability-driven projects. To date, only a handful of plans (NYISO, MISO, PJM), identify transmission solutions based on market-efficiency considerations that have or will next initiate an open competitive process to select a developer (whose project would receive regional cost allocation).[47] Of these, one (NYISO) is focused on solutions specifically required to meet a need created by public policy. No regional transmission plans have as yet selected a transmission project for interregional cost allocation.[48]

[47] In early 2016, CAISO awarded an economically driven project from the 2013/2014 regional transmission plan, through its competitive process (Harry Allen to El Dorado 500 kV line).

[48] One region (NYSIO) is considering two sets of solutions proposed in response to two public-policy transmission needs (one in Western New York and the other to increase throughput in Central New York and the Hudson Valley).

5. Barriers and Incentives to the Implementation of Regional Transmission Plans

This section of the report discusses barriers and incentives to the implementation of transmission projects associated with regional and interregional transmission planning processes that comply with FERC Order Nos. 890 and 1000. The importance and significance of FERC's rules guiding ex ante, regional, and interregional cost allocation are first reviewed because these rules underlie the decision-making processes that form the basis for selecting projects for regional cost allocation. Next, the principal challenge for identifying barriers and incentives—namely, the newness of regional and interregional processes—is discussed with a focus on the information that should be monitored and tracked to better inform future assessments. Finally, the importance of the scope and means by which the benefits of transmission projects are evaluated is discussed in regard to what monitoring should be augmented and how future processes may be aided or enhanced through additional research and demonstration.

5.1. The Importance and Significance of FERC Order Nos. 890 and 1000

Prior to the emergence of ISO/RTOs, regional transmission planning activities generally involved coordination through the regional reliability entity and joint planning at interfaces. The development of regional transmission projects tended to be location-specific arrangements involving only the entities involved in developing the projects. A "regional" project, in this context, simply meant that there was a bi- or multi-lateral agreement among two or more parties (typically, incumbent transmission owners adjacent to one another) to share in developing a project.

The costs of developing the project and the ownership shares governing the use of the project were normally allocated among the partners as part of their contractual agreements, and the details of these agreements were typically included in filings with FERC. The partners, in turn, recovered their costs through their respective FERC- or state-approved tariffs or via FERC-approved contractual arrangements with others seeking to transmit or receive power over the lines. Public or stakeholder scrutiny—by a state public utility commission, for example—could take place through a FERC proceeding regarding ownership or usage agreements, as part of a retail rate-setting process involving a prudency review of an already signed contract, or in a state siting proceeding. In principle, state IRP processes might consider transmission to access off-system resources. However, these reviews did not uniformly consider proposals to build transmission to support off-system sales or project development involving more than one party.

Following the emergence of ISO/RTOs, transmission planning activities in ISO/RTO regions took on a more public character consistent with the formal role that stakeholder involvement plays in ISO/RTO activities. Approval of certain transmission projects for regional cost allocation also emerged as an outcome of these regional transmission planning activities. By and large, projects receiving regional cost allocation were proposed by one or more incumbent transmission owners within one or more of their footprints. Each ISO/RTO developed and evolved region-specific approaches to establish the need for (and selection of) solutions and/or projects that qualified for regional cost allocation. The standards used to judge or select these projects, consequently, varied by region. The outcomes also varied. Some regions' plans identified projects for regional cost allocation; other regions' plans did not. Interregional coordination in the form of information exchange also took place to varying degrees.

In the areas of the country served by vertically integrated utilities, "regional" transmission planning was conducted much as it had been prior to the emergence of ISO/RTOs. Generally speaking, incumbent transmission owners either built transmission to satisfy the needs of their customers or entered into private, bi- or multi-lateral, agreements to develop projects jointly. There were no opportunities for regional cost allocation because transmission projects were paid for solely by the ratepayers of those parties directly involved in developing them. Outside these individual processes, there was no independent forum through which regional needs or solutions could be identified or vetted.

The importance and significance of FERC Order Nos. 890 and 1000 should be viewed against this background of widely varying regional transmission planning practices.

The importance of FERC Orders No. 890 and 1000 is that they articulate a consistent set of nationwide principles for selecting transmission projects that seek regional or interregional cost allocation. The hallmark of these principles is open, transparent processes through which stakeholder input on regional (and interregional) transmission needs, solutions, and projects are vetted. Seen in this light, elimination of preferences for development of these projects by incumbent transmission owners is an essential feature of FERC's effort to level the playing field for selecting projects to receive regional cost allocation.

The significance of these orders is twofold. First, from the standpoint of FERC Order No. 1000, a principal outcome of regional transmission planning is to determine whether there are transmission solutions that should be selected for regional cost allocation. When a region selects a project for regional (or interregional) cost allocation, this means that the region has concluded that a project is more efficient or cost-effective than sub-regional (or regional) alternatives. Second, the resulting regional (or interregional) cost allocation, itself, is expected to ensure that the region-wide (or inter-region-wide) costs are allocated roughly commensurate with estimated benefits.

While transmission providers and/or regions have always evaluated projects that address reliability criteria, and a number of these entities have evaluated projects that address economic impacts and some public policies, FERC Order No. 1000 formally directs, for all regions, consideration of transmission needs that are driven by public policy—i.e., by state or federal laws or regulations. Finally, Order No. 1000 also directed formal coordination on transmission planning among regions.

FERC Order Nos. 890 and 1000 focus primarily on regional transmission projects, which refer specifically to those transmission projects selected in regional transmission plans for purposes of cost allocation. The allocation of these costs, in turn, will follow regional and interregional cost allocation methods that reflect Order No. 1000 cost allocation principles. Regional transmission plans may (or may not) include other types of transmission projects, some of which may address regional needs, yet which are not selected for regional cost allocation. Selection of a project for regional cost allocation requires a finding that the project is more efficient or cost-effective than alternatives.

For example, in parallel with the evolution of FERC Order Nos. 890 and 1000, many merchant transmission projects have also been proposed, and some have been built. Merchant projects often span or cross the regional boundaries of the planning entities reviewed in this report; therefore, these are projects that can also be thought of as either “regional” or “interregional” transmission projects in terms of their geographic scope or the fact that they might originate and terminate in the footprints of different incumbent transmission owners. Yet the costs of these projects are not allocated on a regional (or interregional) basis. Hence, their standing as regional (or interregional) alternatives to projects whose costs are allocated across a region (or regions) is important to bear in mind as planning outcomes from regional transmission planning entities are reviewed.

When considering barriers and incentives to the implementation of transmission projects that have been or might be selected for regional cost allocation, the underlying question that is actually being asked is whether the regions have set the “bar” too high or too low for selection of these projects. We turn now to the basis upon which we recommend these assessments should be made.

5.2. Monitoring and Tracking Regional and Interregional Transmission Planning Activities

As documented in Section 4 of this report, the current record of outcomes—either in terms of the conduct of regional planning processes or the implementation of projects selected through them—is modest. This is hardly surprising because FERC Order No. 1000 was issued in 2011, and the changes it mandated are in process. As seen in Table 1 of this report, the earliest effective date for regional plans is 2013. The earliest effective date for interregional plans is 2014 (and, as of mid-2016, a final compliance order for one regional pair has not yet been issued). FERC recently held a technical conference at which emerging issues stemming from Order No. 1000 were discussed.

Finding 1: *It will be some time before the outcomes of FERC Order Nos. 890 and 1000 can be fully assessed.*

We believe it is premature to draw conclusions regarding the implementation of FERC Order Nos. 890 and 1000 at this time; therefore, it is also premature to identify specific barriers and incentives to the implementation of projects selected for regional cost allocation in the planning processes that have been conducted pursuant to these orders. Although some regions might have been using project selection processes that to varying degrees were later deemed compliant with the orders, final compliance orders have also directed material changes to these processes. Only regional transmission planning processes executed subsequent to final compliance orders should be considered in assessing the impact of the orders.

It should not be surprising that more experience implementing the new requirements prescribed in FERC Order No. 1000 is required in order to provide a reliable basis for assessment. It is inevitable that initial efforts to implement FERC's new requirements will reveal opportunities for refinement, and it is to be expected that such opportunities result in modification of subsequent planning cycles.

Finding 2: *Assessment of FERC Order Nos. 890 and 1000 should be based on information describing the outcomes of regional transmission planning processes, as well as costs (broadly defined) incurred by the processes that achieved these outcomes.*

At this time, activities should be directed toward creating a sound record upon which to assess the regions' progress in implementing FERC's requirements for selection of more efficient or cost effective regional alternatives (see Table 6). From a public policy perspective, the focus should be on monitoring and tracking specific activities that might support future modifications to FERC's orders. FERC Order Nos. 890 and 1000 are an example of an initial order that lays groundwork and a subsequent order that extends the effects of the first order; that is, FERC issued Order No. 890 in 2007, and then, a number of years later, Order No. 1000, which built on and extended aspects of Order No. 890.

Table 6. Regional Transmission Planning Outcomes and Process Elements That Should be Monitored

<table>
<tr><th colspan="2">Planning Outcomes</th></tr>
<tr><td>Projects selected for regional cost allocation</td><td rowspan="3">For all planning outcomes:
• Physical characteristics of projects
• Project type (reliability, economic, public policy, regional, interregional)
• Developer type (incumbent/non-incumbent)
• How selection criteria were (or were not) satisfied
• Project costs – proposed (actual, if appropriate)</td></tr>
<tr><td>Projects proposed but not selected for regional cost allocation</td></tr>
<tr><td>Projects not proposed for regional cost allocation but evaluated as alternatives to project that were proposed yet not selected for regional cost allocation</td></tr>
</table>

<table>
<tr><th colspan="2">Planning Processes</th></tr>
<tr><td>Economic and related benefits</td><td>• Benefits considered/evaluation methods (e.g., use of production-cost modeling tools)
• Consistency of modeling assumptions with other planning activities, including sub-regional and interregional activities (also applies to reliability analyses)
• Treatment of uncertainty</td></tr>
<tr><td>Process-related costs</td><td>• Project selection process steps/staffing requirements/ schedule
• Number of/time commitments for stakeholder workshops/ meetings</td></tr>
</table>

Source: Lawrence Berkeley National Laboratory

Projects that are selected for regional cost allocation are an obvious measure to track as an outcome of regional planning processes, but they are not the only outcome, and they may not be the most important outcome to track. Regions can and will legitimately conclude that there are no regional (or interregional) needs for transmission projects whose costs should be allocated regionally. The reason might be either that regional solutions are not more efficient or cost-effective than alternatives.

Outcomes will, nevertheless, always be an important element to track. The outcomes tracked should include the fate of projects that are not selected for regional cost allocation but are built nonetheless and recover their costs through other means. Further, because projects proposed for regional cost allocation may be found not to be more efficient or cost-effective than alternatives for meeting regional transmission needs, it is the extent to which regional needs are (or are not) met that should be monitored. That is, monitoring should not focus solely on projects that are proposed for regional cost allocation.

Transmission investment metrics[49] recently presented by FERC staff will contribute to the record that must be created because these metrics track outcomes. Here, again, it is important to consider the drivers for investment (i.e., for what purpose transmission is needed), in addition to the investments, themselves. Further disaggregation of investment in transmission by type (e.g., whether project costs were allocated regionally or by other means, whether projects met regional transmission or other needs) may be appropriate. In addition, the Percentage of Non-incumbent Bids/Proposals metric, which focuses on an important element of FERC Order No. 1000, could consider also tracking outcomes from processes in which both incumbent and non-incumbent transmission developer compete.

A second outcome to monitor is the actual cost of projects selected for regional cost allocation. Actual project costs may exceed or be less than the costs used in planning evaluations. What the actual costs turn out to be, and how differences between projected and actual costs are recovered (or not recovered) from ratepayers, are important issues. This is true both from the standpoint of equitably balancing the risks of project development between ratepayers and developers and from the standpoint of improving estimates used in evaluations of other prospective transmission projects in the planning process.

Turning to the process- (rather than outcome-) related aspects of regional planning that should be monitored, it is useful to distinguish between two possible areas of focus that serve distinct purposes. On the one hand, FERC Order Nos. 890 and 1000 require monitoring of the openness and transparency of (as well as stakeholder participation in) regional planning processes. Actions to address allegations of shortcomings in these areas are already within the scope of FERC's compliance authorities. Administrative processes and avenues for surfacing and addressing these allegations already exist. Accordingly, there is little need to pursue independent monitoring of this aspect of these processes at this time. On the other hand, it is appropriate to also track the administrative costs (including a

[49] FERC. 2016. *Transmission Investment Metrics: Initial Results.* https://www.ferc.gov/legal/staff-reports/2016/03-17-16-report.pdf

meaningful recognition of those borne by stakeholders and developers) associated with managing and participating in regional planning and project-selection activities as well as the benefits considered in these activities. A goal of this tracking would be to identify issues that might require attention in the future. The challenge will lie in establishing appropriate baselines against which costs can be meaningfully compared.

Carrying out the planning-process requirements of FERC Order Nos. 890 and 1000 imposes real costs, (both time and resource requirements) on regional planning staffs, regional stakeholders, and project developers. Common sense suggests that these processes should not impose or create additional costs that in aggregate exceed the benefits that the processes seek to achieve. Therefore, the costs associated with managing and participating in regional planning and selection processes should also be monitored. It might be found, for example, that existing minimum size or cost thresholds should be modified to enable screening a greater number or types of projects for more streamlined evaluation and decision-making processes compared to the processes carried out for larger projects—while still following FERC's requirements for openness, transparency, and stakeholder involvement.

This is an area where we should expect that experience alone, through repeated planning cycles, will lead naturally to efficiencies. But expectations are not guarantees, and identifying new opportunities for increased process efficiencies should always be a focus. Information on the costs involved in running these processes is essential for guiding efforts to pursue these opportunities.

The subject of the benefits considered in regional planning warrants a longer and separate discussion because it encompasses a more open-ended set of considerations that includes but also extends beyond monitoring and tracking activities. We address this topic in the next subsection.

5.3. Fully Considering the Benefits of Regional Transmission Projects

A region's finding that a project is more efficient or cost-effective than alternatives hinges critically on the definition and scope of the benefits that were considered. All other things being equal, widening the range of benefits considered may result in a project being found more efficient or cost-effective and that it may have more benefits to be distributed among beneficiaries. Hence, widening the range of benefits considered might result in more projects being selected for regional cost allocation. Broadening awareness of and demonstrating the importance of considering additional benefits is essential for building stakeholder confidence and support.

Finding 3: *The range of transmission benefits considered varies widely in regional transmission planning processes, as does the means by which benefits are evaluated. Moreover, the consideration of transmission benefits is an evolving practice among regional transmission planning entities.*

There is wide variation among current practices. On the one hand, the benefits considered by each region represent the region's acceptance of the scope of and means by which benefits are currently being taken into account. On the other hand, the variations among practices in different regions suggest that there may be opportunities for evolution or growth in the scope of benefits that are considered by one region based on the experiences of other regions or through the introduction (and acceptance by stakeholders) of other forms of benefits or means for evaluating them. Transmission needs created by public policies are an example. Though meeting transmission needs that public policies create is not a benefit in a direct economic sense, it is a factor that can be used to justify selection of projects for regional cost allocation. In a very simplified sense, if all other things are equal, broadening the range of public-policy needs considered could, in principle, lead to selection of more projects for regional cost allocation.

A trend among the planning regions whose processes are reviewed in this report is the growing and evolving use of production-cost models to estimate the economic benefits of transmission projects. Some regions are just beginning to use these tools to augment or support their economic evaluations of projects. Monitoring and tracking growth in the use of these tools, and in the sophistication of their use is, therefore, an appropriate focus.

In monitoring the growth and sophistication of use of formal study tools (such as production-cost models), a particular area for emphasis is the selection and harmonization of key input assumptions—such as load growth, fuel costs, and hurdle rates—if these are used. Monitoring should focus on documenting the basis for key assumptions and understanding their consistency with related assumptions, both internal to the planning area (such as the relationship between load growth and population growth or the use of similar assumptions in related studies), and external to the planning area (such as forecasts of natural gas prices in adjacent regions). These modeling considerations apply equally to reliability analyses.

Some regions, acknowledging the uncertainty inherent in planning studies, have sought to enhance the usefulness of their applications of production-cost models and other tools by formally considering multiple scenarios. Scenario analysis provides a richer base of information upon which to assess the economic value of projects because it more fully reveals the dependency of outcomes on the selection of input assumptions.

Finding 4: *There is emerging evidence on and growing sophistication in evaluating transmission benefits that have not yet been considered formally in regional transmission planning processes.*

The literature is growing on benefits of transmission other than those that can be readily assessed with production-cost modeling tools, no matter how sophisticated those tools are. These benefits include those associated with the option value created by transmission as a hedge against future contingencies.[50] Some ISO/RTOs are beginning to consider some of these issues.[51] These efforts should be encouraged, and their merits and usefulness discussed critically by the regions and stakeholders involved in those regional transmission planning processes. Due consideration must be paid to the fact that uncertainty is an inescapable element in all assessments of future benefits.

Although advanced analysis techniques are not currently an element of regional transmission planning practices, the academic community has been active in adapting and applying these techniques to transmission-planning questions, and these approaches are emerging in real-world planning environments. Formal recognition of and consistent treatment of uncertainty is a growing focus of these activities.[52] What is important in the short run is not formal adoption of these advanced methods by regional planners, but the insights that these methods may provide to the regions and their stakeholders by complementing production-cost-model-based study methods.

5.4. Summary

FERC Order Nos. 890 and 1000 have significantly changed the manner and form of regional transmission planning by creating open and transparent transmission planning processes. These processes are a powerful tool that regions can wield to address their own transmission needs as well as needs shared with neighboring regions. Still, the planning process established by these FERC orders is only one of several means by which regional and interregional transmission needs can be met. The effectiveness of the planning processes established by these FERC orders will take time to assess. It is essential to begin establishing the record for this assessment now, to inform timely decisions on whether or how the requirements and processes might be enhanced to ensure that regional needs are met efficiently and cost effectively.

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50 See, for example, Budhraja, V., et al. 2009. "Improving Electric Resource Planning by Considering the Strategic Benefits of Transmission." The Electricity Journal 22(2), March; and Pfeifenberger, J. and D. Hou. 2012. "Transmission's True Value." Public Utilities Fortnightly. September; and Chang, J., J Pfeifenberger, and J Hagerty. 2013 "The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments. WIRES. July.
51 See Southwest Power Pool. 2016. *The Value of Transmission*. January 2016. https://www.spp.org/documents/35297/the%20value%20of%20transmission%20report.pdf
52 See, for example, Hobb, B. et al. 2016. "Adaptive Transmission Planning." IEEE Power and Energy. July/August. http://ieeexplore.ieee.org.ezproxy.puc.cl/xpl/mostRecentIssue.jsp?punumber=8014

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