

Regional Transmission Planning

A review of practices following FERC Order Nos. 890 and 1000

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Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000

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Acronyms

CAISO	California Independent System Operator
ERO	Electricity Reliability Organization
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council, Inc.
IRP	Integrated Resource Plan
ISO	Independent System Operator
ISO-NE	ISO New England
kV	kilovolt
LBNL	Lawrence Berkeley National Laboratory
MISO	Midcontinent Independent System Operator
MW	Megawatt
NERC	North American Electric Reliability Corporation
NTTG	Northern Tier Transmission Group
NYDPS	New York Department of Public Service
NYISO	New York Independent System Operator
PJM	PJM Interconnection
RRO	Regional Reliability Organization
RTO	Regional Transmission Organization
SPP	Southwest Power Pool
SCRTP	South Carolina Regional Transmission Planning
SERTP	Southeastern Regional Transmission Planning

Executive Summary

Federal Energy Regulatory Commission (FERC) Order Nos. 890 and 1000¹ established requirements that transmission planning regions must follow in regional transmission planning and allocating the costs of new transmission facilities. Order No. 890, issued in 2007, outlined general requirements for local as well as regional transmission planning practices and procedures. Order No. 1000, issued in 2011, laid out specific requirements for: (1) regional transmission planning; (2) consideration of transmission needs driven by public policy requirements; (3) non-incumbent transmission development; (4) interregional transmission coordination; and (5) cost allocation for transmission facilities that have been selected in a regional transmission plan for purposes of cost allocation. This report reviews how these FERC orders are being implemented by the 12 transmission planning regions recognized by FERC.²

We focus on the practices for selecting transmission projects in a regional transmission plan for purposes of cost allocation that are at the center of Order No. 1000, which imposes three requirements, among others: First, regional transmission planning processes must consider and evaluate, on a non-discriminatory basis, possible transmission solutions (and non-transmission alternatives) to address regional transmission needs and must result in a regional transmission plan. Second, to select a transmission project for regional cost allocation, a region must first select the project in its regional transmission plan as a more efficient or cost-effective transmission solution, compared to alternatives, to address regional transmission needs. Third, the region must have in place a method for allocating the costs of a new transmission facility that has been selected in the regional transmission plan for purposes of cost allocation, which complies with the principle of allocating the costs in a manner that is at least roughly commensurate with the project's benefits.

FERC Order No. 1000 requires regional transmission planning with the goal of selecting the more efficient or cost-effective transmission solutions to meet regional transmission needs, but it does not require that transmission projects be selected for regional cost allocation. Regions must consider and evaluate alternative transmission solutions that might meet the region's transmission needs more efficiently or cost-effectively than solutions identified by individual transmission providers in their local transmission planning processes. However, they may also conclude that they have a regional need for transmission *and* that this need can be met by means that do not involve or require the selection of a transmission project in the regional transmission plan for purposes of cost allocation. Therefore, this report addresses the role of regional cost allocation in the context of the related transmission planning processes within a region.

This review is timely because FERC's regional transmission planning requirements are relatively recent, and their implementation is evolving as experience with them grows. Our review of the current state of

¹ See Order No. 1000: <http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf> and Order No. 890: <http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>

² The 12 transmission planning regions recognized by FERC are, with one exception, functionally and geographically different than the 8 regions identified as Regional Reliability Entities under the delegated functions of the Electricity Reliability Organization, the North American Electric Reliability Corporation. The exception is FRCC.

the practices for selecting transmission projects in a regional transmission plan for purposes of cost allocation helps establish a baseline against which future regional transmission planning developments can be assessed. In addition, because FERC's orders provide for regional diversity, our documentation of regional differences offers a basis for examining regional practices in relation to one another.

Eto 2016³ is a direct predecessor to this report. That report described the governance structures and decision-making procedures of the 12 transmission planning regions, summarized their overall regional transmission planning processes and studies, and reviewed recent transmission planning outcomes, focusing on transmission projects selected for regional (or interregional) cost allocation. This report draws from and adds to the information presented in the earlier report as follows: This report enlarges the earlier report's discussion of the sponsorship and competitive bidding selection by linking a region's general reliance on one of the two approaches to fundamental differences among the regions, which stem from the scope of the transmission planning activities they conduct. This report extends the basic descriptions of how the transmission planning regions assess regional transmission needs that are driven by reliability, public policy requirements, and economic considerations by explaining how these assessments are sequenced within each region's transmission planning processes. Finally, this report expands on the recommendations presented in the earlier report regarding aspects of the regional transmission planning processes and outcomes that should be monitored over time. A specific focus of this report's discussion is identifying areas where current publicly available sources of information should be bolstered to support monitoring of regional transmission planning.

While no two regions have identical selection approaches, the approaches they follow to select transmission projects in the regional transmission plan for purposes of cost allocation can be grouped under one of two general headings: the project *sponsorship* approach and the project *competitive bidding* (previously referred to as *competitive solicitation*) approach.^{4,5} The type of approach used is related to more fundamental differences in the scope of the transmission planning activities that the different regions conduct. For the purposes of this discussion, it is useful to distinguish between two broad groups within the 12 transmission planning regions recognized by FERC: the first group of transmission planning regions consists of vertically integrated utilities that operate outside the footprints of independent system operators or regional transmission organizations (ISO/RTO), which we refer to as "non-ISO/RTO regions." The second group consists of the ISO/RTOs, which we will refer to as "ISO/RTO regions."⁶ Despite these groupings, what is inherent to the transmission planning activities of

³ Eto 2016. *Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans*. LBNL September 2016.

⁴ Note that FERC uses the term "competitive bidding," instead of "competitive solicitation." See, for example, Further Supplemental Notice of Technical Conference, Competitive Transmission Development Technical Conference, Docket No. AD16-18-000, at 14 (June 20, 2016). Consistent with this practice, this report will use the term competitive bidding.

⁵ Under the sponsorship approach, the competition generally involves both the selection of a proposed transmission solution as well as the developer for it. Under the competitive bidding approach, the competition generally involves only the selection of a developer for a pre-identified transmission solution. See Further Supplemental Notice of Technical Conference, Competitive Transmission Development Technical Conference, Docket No. AD16-18-000, at 14 (June 20, 2016).

⁶ MISO and SPP can also be described as regions that are "made up of vertically integrated utilities." Similarly, it also bears noting that the regions sometimes include a significant number of cooperative or public power utilities that are not vertically integrated but that also participate in the regional transmission planning process.

all regions is that regional transmission needs are driven either by requirements to maintain the reliability of the grid, by public policy requirements, or by economic considerations.

In most non-ISO/RTO regions, the participating utilities' individual transmission plans are combined to form a baseline regional transmission plan.⁷ The baseline regional transmission plan is then used to evaluate proposals from stakeholders and prospective transmission developers for both regional transmission needs and regional transmission solutions (including non-transmission alternatives⁸) that will meet these needs on what is essentially a need-by-need and project-by-project basis. The non-ISO/RTO regions generally use a *sponsorship* approach that both selects a regional transmission solution and a transmission developer for that transmission solution, which is then also eligible for regional cost allocation.⁹

In the ISO/RTO regions, the ISO/RTOs have responsibilities for a much broader scope of transmission planning (e.g., for all of the highest-voltage transmission lines within their respective regions) than do the non-ISO/RTO regions. The local transmission plans, if any, of the transmission owners within the ISO/RTO footprint provide input to ISO/RTO planning, but the ISO/RTO also conducts additional planning activities independently. In other words, while many of the non-ISO/RTO regions use their baseline regional transmission plans as a basis for regional transmission planning, the ISO/RTOs generally rely less on any local transmission plans to do so. As a result, there is no role for a separate, initial baseline regional transmission plan. In ISO/RTO regions that rely on a sponsorship approach, the selection of a regional transmission solution is closely tied to the selection of a qualified transmission developer. In ISO/RTO regions that rely on a competitive bidding approach, the identification of regional transmission solutions is a largely distinct process from the selection of a qualified transmission developer.

Both ISO/RTO and non-ISO/RTO regions may find that their regional transmission needs may be met more efficiently or cost-effectively by means that do not involve or require selection of transmission projects whose cost may be allocated regionally. Consequently, in assessing how regions meet their regional transmission needs, it is important to consider how *all* transmission projects are planned within a region, not just transmission projects that have been selected in the regional transmission plan for purposes of cost allocation. That is, while a region may not identify any more efficient or cost-effective regional transmission solutions and, therefore, not select any projects in the regional transmission plan for purposes of cost allocation, it has an obligation to assess whether there may be more efficient or cost-effective regional solutions—even if the transmission needs would otherwise be met through local transmission facilities.

With this framing as an introduction, we next describe how specific regional needs for transmission—*reliability*, *public policy requirement*, and *economic*—are assessed by the transmission planning regions,

⁷ ColumbiaGrid is an exception; ColumbiaGrid does not develop an initial baseline plan for the region.

⁸ FERC concluded that the issue of cost recovery for non-transmission alternatives was beyond the scope of transmission cost allocation reforms that it would adopt in Order No. 1000.

⁹ WestConnect is an exception; WestConnect uses a competitive bidding approach.

how these assessments are sequenced, and how the standard of “more efficient or cost-effective” is applied.

Transmission needs driven by reliability requirements have the longest history of being formally evaluated by regions, and are generally considered at the start of (and even prior to or outside of) a regional transmission planning cycle. Where and how reliability-driven transmission needs are addressed in relation to a regional transmission planning process depends on whether and to what extent the transmission planning region itself is responsible for complying with mandatory national, regional, and local reliability rules. Regions that are not responsible for this compliance must first take into account the findings of the North American Electric Reliability Corporation (NERC)-registered entities that are responsible for compliance with applicable reliability planning standards. Regions that assume responsibility for this compliance must make findings that their planned transmission facilities will comply with these rules, independent of findings they make regarding regional cost allocation for specific projects. The “more efficient or cost-effective” standard generally focuses on whether the cost of a regional solution is lower than the cost of an alternative or the reliability benefits of a regional solution are greater than those of alternatives (often in the form of reduced transmission losses). The alternative could be either another proposed regional solution or a set of local solutions (e.g., those that together would involve more than one transmission owner’s footprint within the region).

Transmission needs driven by public-policy are those that address public policies established by local, state, or federal laws or regulations. This category of transmission needs was the one most recently added to the list of needs that public utility transmission providers are required to assess. These assessments, which must be conducted periodically, tend to follow after an assessment of reliability-driven needs and potential regional transmission solutions, though they are also sometimes conducted in parallel or jointly with other needs assessments. The assessment processes follow common steps in all regions. First, the regions determine whether and what public policy requirements create needs for a regional transmission solution(s). Stakeholders, including states, within all regions have an important role in the identification of public policy requirements which might create these needs. In some ISO/RTO regions, there are formal arrangements with either a single state PUC (for single-state ISO/RTOs, such as CAISO and NYISO) or standing committee of PUCs to identify these needs. Then, separately or jointly with the identification of transmission needs, they consider proposals for regional solutions that might meet them. The basic test remains whether a regional transmission solution will meet these needs more efficiently or cost-effectively than alternatives. The alternatives, again, may be either other regional solutions or local solutions that the regional transmission solution might displace/replace.

Transmission needs driven by economics are needs associated with reducing congestion costs or integrating efficient new resources and new or growing loads. These needs assessments are sometimes conducted after other regional needs assessments have been completed, but are sometimes conducted in parallel or jointly with the other needs assessments. There are two basic approaches for evaluating the economic benefits of projects; each is generally aligned with the type of region. In most non-ISO/RTO regions, the economic benefit of a regional transmission solution is determined by considering,

among other benefits such as changes in transmission losses, the costs of the local transmission projects that would be replaced (or “avoided”) by a regional solution. In all ISO/RTO and some non-ISO regions, the economic benefit of a regional transmission solution is determined by also considering regional changes in production costs (sometimes along with other generation-related impacts) that would result from the construction and operation of a proposed solution. These approaches translate in spirit but to varying degrees to means by which the “more efficient or cost-effective” standard is subsequently (and separately) applied by these regions to evaluate regional solutions that might meet these needs.

Our analysis concludes by describing regional (and local) transmission planning outcomes and practices that should be reviewed and evaluated over time. The goal of these reviews should be to assess whether and how regional transmission needs are being met. We emphasize the importance of a holistic and, to some degree, region-specific approach to these assessments. This includes considering transmission projects selected in a regional transmission plan for purposes of cost allocation as well as other means that regions, as a whole (not just regional transmission planning entities), pursue to ensure regional transmission needs are met efficiently or cost-effectively. We describe a broad range of planning outcomes and activities that should be reviewed to support these assessments, including information on the characteristics of the transmission that is planned and built as well as information on the actual, realized impacts of built transmission in terms of reliability, economics, and public policy requirements. Review activities should also gather information on how regional transmission planning processes are conducted, and the extent to which these planning processes are (or are not) providing meaningful benefits to stakeholders and consumers. Finally, we identify limitations in the public information currently available to support the recommended assessments. Remedying these limitations would provide a stronger basis for evaluating the effectiveness of regional transmission planning activities.

1. Introduction

Federal Energy Regulatory Commission (FERC) Order Nos. 890 and 1000¹⁰ established requirements that transmission planning regions must follow in regional transmission planning and allocating the costs of new transmission facilities. Order No. 890, issued in 2007, outlined general requirements for local as well as regional transmission planning practices and procedures. Order No. 1000, issued in 2011, laid out specific requirements for: (1) regional transmission planning; (2) consideration of transmission needs driven by public policy requirements; (3) non-incumbent transmission development; (4) interregional transmission coordination; and (5) cost allocation for transmission facilities selected in a regional transmission plan for purposes of regional cost allocation.

This report reviews how these orders are being implemented by the 12 transmission planning regions recognized by FERC: California ISO (CAISO), ColumbiaGrid, Florida Reliability Coordinating Council (FRCC), ISO New England (ISO-NE), Midcontinent ISO (MISO), New York ISO (NYISO), Northern Tier Transmission Group (NTTG), PJM Interconnection (PJM), South Carolina Regional Transmission Planning (SCRTP), Southeastern Regional Transmission Planning (SERTP), Southwest Power Pool (SPP), and WestConnect (see Figure 1).

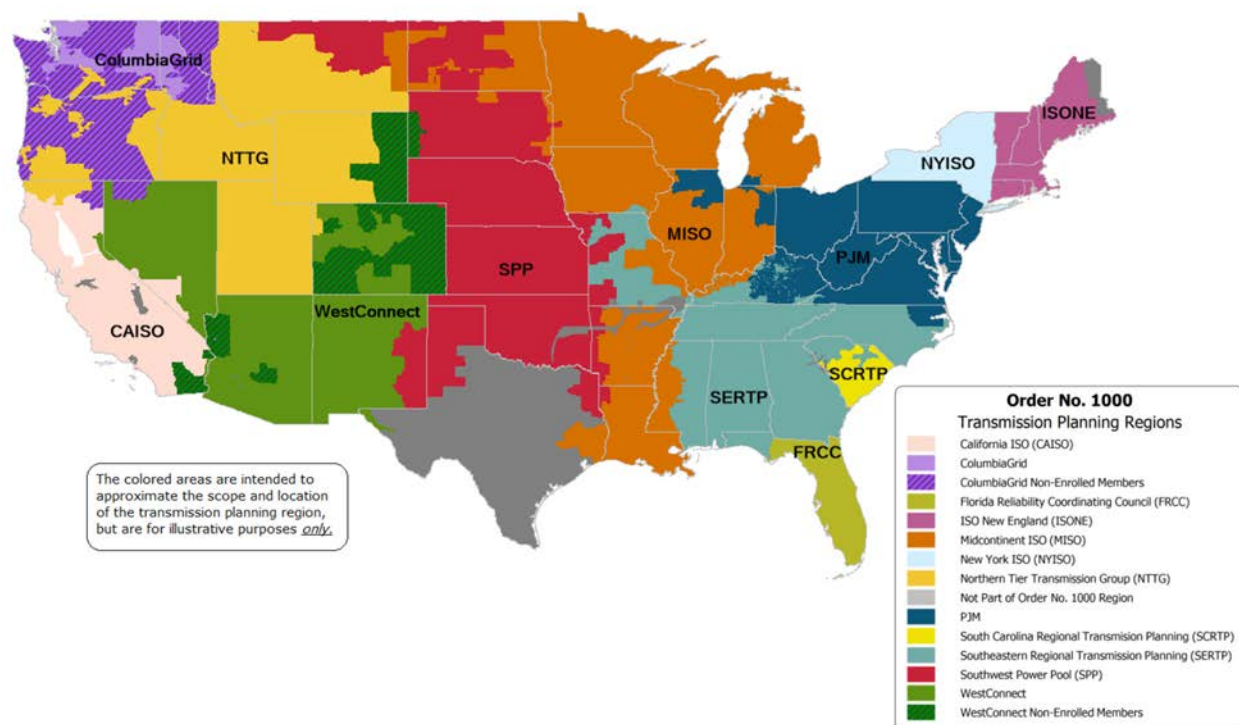


Figure 1. FERC-Designated Transmission Planning Regions

Source: <https://www.ferc.gov/industries/electric/indus-act/trans-plan.asp>

¹⁰ See Order 1000: <http://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf> and Order 890: <http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf>

We focus on the regional transmission planning processes for selecting transmission projects for regional cost allocation that are at the center of Order No. 1000, which imposes three requirements, among others: First, regional transmission planning processes must consider and evaluate, on a non-discriminatory basis, possible transmission (and non-transmission alternatives) to address regional transmission needs and must result in a regional transmission plan. Second, to select a transmission project for regional cost allocation, a region must first select the project in its regional transmission plan as a more efficient or cost-effective transmission solution, compared to alternatives, to address regional needs. Third, the region must have in place a method for allocating the costs of a new transmission facility that has been selected in its regional transmission plan for purposes of cost allocation, which complies with the principle of allocating the costs in a manner that is at least roughly commensurate with the project's benefits.

FERC Order No. 1000 requires regional transmission planning to consider and evaluate possible transmission alternatives that may be selected for regional cost allocation as more efficient or cost-effective transmission solutions to meet regional transmission needs, but it does not require that transmission projects be selected for regional cost allocation. Regions must consider and evaluate alternative transmission solutions that might meet the region's transmission needs more efficiently or cost-effectively than solutions identified by individual transmission providers in their local transmission planning processes. However, they may also conclude that they have a need for a transmission project *and* that this need can be met by means that do not involve or require the selection of a transmission project for regional cost allocation. Therefore, this report addresses the role of regional cost allocation in the context of the local and regional transmission planning processes within a region.

This review is timely because FERC's regional transmission planning requirements are relatively recent, and their implementation is evolving as experience with them grows.¹¹ Our review of the current state of the practices for selecting transmission projects in a regional transmission plan for purposes of cost allocation helps establish a baseline against which future regional transmission planning developments can be assessed. In addition, because FERC's orders provide for regional diversity, our documentation of regional differences offers a basis for examining regional practices in relation to one another.

This report builds on three recent studies that examine related aspects of regional transmission planning. We briefly describe these studies below to give background and explain the motivation for the selection of topics addressed in this report.

Fink et al. 2011¹² reviewed cost allocation practices and transmission planning by the seven U.S. independent system operators and regional transmission organizations (ISO/RTOs). This report updates

¹¹ FERC examined many Order No. 1000 issues at a June 2016 Competitive Transmission Development Conference in Docket No. AD16-18-000. FERC requested post-conference comments on some issues in an August 3, 2016 Notice Inviting Post-Technical Conference Comments. At the time this report was prepared (Summer 2017), no further action has been taken in the this docket.

¹² Fink, Fink, S., K. Porter, C. Mudd, and J. Rogers. *A Survey of Transmission Cost Allocation Methodologies for Regional Transmission Organizations*. NREL. February, 2011

Fink et al.'s review by describing the significant changes that these cost allocation and transmission planning processes have undergone at the six ISO/RTO-led regional transmission planning entities that are subject to Order No. 1000.¹³

ICF 2016¹⁴ reviewed the transmission planning practices of the seven U.S. ISO/RTOs with a focus on the studies they conduct to identify reliability-driven transmission needs. This report expands on that review by updating this review and also describing how transmission needs driven by public policy requirements and economic considerations are assessed, and how these assessments are related to (or integrated with) one another. This report also describes how transmission (and non-transmission) solutions are considered to meet identified needs, and, ultimately, how transmission projects may be selected in a regional transmission plan for purposes of cost allocation.

This report also expands on both of the above earlier studies by describing transmission regional cost allocation practices and transmission planning processes utilized by the six ISO/RTO transmission planning regions and in the six transmission planning regions that are not ISO/RTOs.

Eto 2016 is a direct predecessor to this report. That study described the governance structures and decision-making procedures of the 12 transmission planning regions recognized by FERC on compliance with Order No. 1000. It summarized their transmission planning processes and studies as well as emerging features of their interregional transmission coordination activities. It also reviewed recent transmission planning outcomes, focusing on projects selected for regional (or interregional) cost allocation. Finally, it developed a list of regional transmission planning features and outcomes that could be tracked to follow their evolution over time.

This report draws from and adds to the information presented in Eto 2016 as follows:

Section 2 of this report describes how the regions frame or structure their transmission planning processes within which transmission projects may be selected in the regional transmission plan for purposes of cost allocation. This discussion enlarges the discussion of the sponsorship and competitive bidding approaches first presented in Eto 2016. It does this by linking a region's general reliance on one of the two approaches to more fundamental differences among the regions, which stem from the scope of the planning activities they conduct. This perspective also highlights the importance of considering how all transmission projects planned within a region might meet regional needs, not just projects that might be proposed for regional cost allocation.

Section 3 describes how the transmission planning entities assess regional transmission needs that are driven by reliability, public policy requirements, and economic considerations. We extend Eto 2016's basic descriptions of these types of assessments by discussing them in the context of the larger set of planning processes that take place within regions (as outlined in Section 2). Putting the assessments in

¹³ This report does not review the transmission planning activities of the Electric Reliability Council of Texas (ERCOT); ERCOT is not subject to FERC Order Nos. 890 and 1000.

¹⁴ ICF International 2016. *Comparison of Transmission Reliability Planning Studies of ISO/RTOs in the U.S.* February 2016.

this context helps to explain the sequencing of assessments. We also review, in more detail than was covered in Eto 2016, how the standard for determining whether a regional solution is more efficient or cost-effective than alternatives is applied to solutions that are proposed to address regional transmission needs.

Section 4 expands on the recommendations presented in Eto 2016 regarding aspects of the regional transmission planning processes and outcomes that should be reviewed and evaluated over time. A specific focus of this discussion is identifying areas where current publicly available sources of information should be bolstered to support assessments of regional transmission planning.

The main sections of this report are augmented by stand-alone descriptions, in Appendices A–L, of the current transmission planning practices of each of the 12 transmission planning regions. The appendices provide additional background on the origins of each region, as well as the history of regional transmission planning and an overview of current transmission planning practices within it. If a planning study involving an economic assessment has been conducted recently by a region, a summary of this study is also included in the appendix.

2. Framing the Process of Selecting Projects for Regional Cost Allocation

In this section, we describe how the regions frame or structure the overall transmission planning processes within which transmission projects may be selected in a regional transmission plan for purposes of cost allocation. This discussion enlarges Eto 2016's discussion of the sponsorship and competitive bidding approaches by linking each region's general reliance on one of these approaches to more fundamental differences among the regions and the scope of transmission planning activities they conduct. This discussion highlights the importance of considering how all transmission projects are planned within a region—not just those that might be selected in the regional transmission plan for purposes of cost allocation. This view of the projects moving through or alongside of regional processes provides a vantage point from which to understand how the regions assess transmission needs and solutions for reliability, public policy requirements, and economic considerations, which are discussed in Section 3.

2.1 Approaches for Selecting Transmission Projects for Regional Cost Allocation and the Differing Scopes of Regional Planning Entities

Eto 2016 described the processes relied on by transmission planning regions to select transmission projects in a regional transmission plan for purposes of cost allocation as broadly following one of two approaches: *sponsorship* and *competitive bidding* (previously referred to as *competitive solicitation*).¹⁵

Under the *sponsorship* approach, incumbent and non-incumbent transmission developers are invited to propose specific transmission projects to solve or address a regional transmission need. The transmission planning region then evaluates these proposals and determines whether one is more efficient or cost effective than the alternatives to it. If a region finds that a transmission project is more efficient or cost effective than alternative options, including, potentially, local transmission solutions, or designing its own solution, the project is selected for regional cost allocation, and the proposer becomes eligible to use the regional cost allocation method for the project. Under the sponsorship approach, the competition involves both the selection of a proposed transmission solution as well as the developer for it.¹⁶

Under the *competitive bidding* approach, regional transmission needs are first evaluated to determine whether they require a transmission solution, and, if so, the region selects the more efficient or cost-effective solution to meet those needs. The competitive bidding process, which is open to both qualified incumbent and non-incumbent transmission developers, is then used to select the developer for the pre-identified transmission solution. That is, the process for identifying transmission as a

¹⁵ Note that FERC uses the term “competitive bidding,” instead of “competitive solicitation.” See, for example, Further Supplemental Notice of Technical Conference, Competitive Transmission Development Technical Conference, Docket No. AD16-18-000, at 14 (June 20, 2016). Consistent with this practice, this report will use the term competitive bidding.

¹⁶ The sponsorship approach is sometimes referred to as a “needs-based” approach.

solution takes place prior to—and is separate from—the competitive process used to select a developer for the identified solution.¹⁷

For the purposes of this discussion, it is useful to distinguish between two broad groups within the 12 transmission planning regions recognized by FERC: The first group of transmission planning regions consists of vertically integrated utilities that operate outside the footprints of independent system operators or regional transmission organizations (ISO/RTO), which we will refer to as “non-ISO/RTO regions.” The second group consists of the ISO/RTOs, which we will refer to as “ISO/RTO regions.”¹⁸

A majority of the transmission planning regions rely on the sponsorship approach (see Figure 2.) The ISO/RTO regions that use a sponsorship approach are ISO-NE, NYISO, and PJM. The non-ISO/RTO regions that use a sponsorship approach are ColumbiaGrid, FRCC, NTTG, SCRTP, and SERTP. CAISO, MISO, SPP, and WestConnect use a competitive bidding approach.

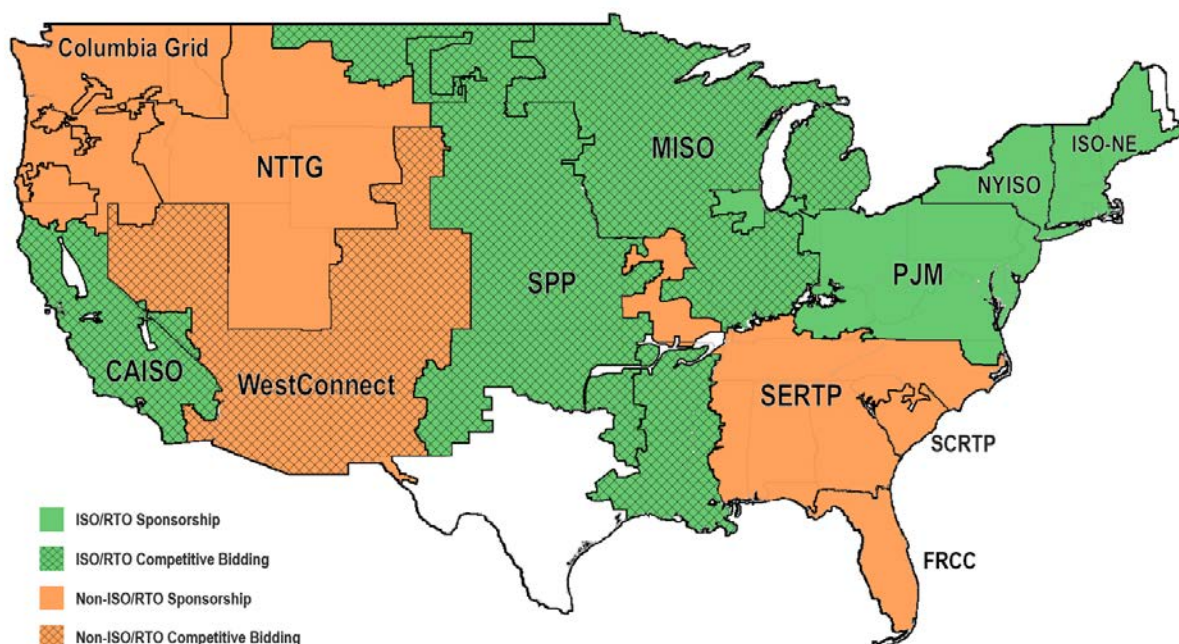


Figure 2. Selection Process for Regional Cost Allocation

Differences in the scope of the transmission planning activities conducted by the transmission planning regions that are recognized by FERC are important for understanding how the selection approaches described in the previous subsection are implemented. In Section 2.2, we describe how the sponsorship approach is implemented in the majority of non-ISO/RTO regions (ColumbiaGrid, FRCC, NTTG, SCRTP, and SERTP). The processes used to select transmission projects in the regional transmission plan for purposes of cost allocation bear important similarities among these regions and, taken together,

¹⁷ The competitive bidding approach is sometimes referred to as a “bid-based” approach.

¹⁸ MISO and SPP can also be described as regions that are “made up of vertically integrated utilities.” Similarly, it also bears noting that the regions sometimes include significant cooperative or public power utilities that are not vertically integrated but that also participate in the regional transmission planning process.

highlight the focused role that these regions play in implementing the requirements of FERC Order No. 1000. In Section 2.3, we describe how certain ISO/RTOs' broader scope of transmission planning responsibilities and approaches to planning lead to use of the sponsorship approach (ISO-NE, NYISO, PJM). The competitive bidding approach (CAISO, MISO, SPP, WestConnect) is described and contrasted to the sponsorship approach in Section 2.4.

2.2 The Sponsorship Approach Used in Non-ISO/RTO Regions

In the non-ISO/RTO regions, local transmission planning is conducted initially, solely, and independently by each utility with oversight provided by its state utility regulatory commission or local governing board.¹⁹ Transmission projects, which are regional in the sense that they involve more than one utility's footprint, are developed, and costs/responsibilities allocated/agreed upon, on a bi- or multi-lateral basis among participating utilities, within these state and/or local oversight processes. Access to off-system resources (or off-system sales) through new (or existing) transmission may be considered and evaluated against other supply- and demand-side resource options through an inclusive regulatory framework known as integrated resource planning (IRP). In these regions, the decision to build transmission reflects an agreement between the utility and its overseers of the appropriateness of this option both for the utility's ratepayers and for its shareholders or owners/governing boards. Importantly, these settings provide for local consideration of regional or other non-local interests from the standpoint of how local interests would be impacted (i.e., how the local area would benefit from, and how much it would pay for, a project that is regional in nature).

This background makes it straightforward to understand how these regions use a sponsorship approach to select transmission projects for regional cost allocation. The region aggregates the individual plans of each participating transmission provider into an initial (or baseline) regional transmission plan.²⁰ Therefore, although some harmonization may be required among the local transmission plans to ensure that the regional transmission plan adequately addresses reliability considerations and that affirmative regional transmission planning is performed, resource-based and public-policy-related decisions regarding the appropriateness of transmission solutions have already been made (from a local perspective) and are fully reflected in the combined baseline regional transmission plan. It is important to recognize that the baseline regional transmission plan does not contain transmission projects whose costs are allocated to the entire region through the region's Order No. 1000 regional cost allocation method.

The baseline regional transmission plan, then, establishes the basis against which potential regional transmission needs and solutions to address regional transmission needs are considered.²¹ In the case of those proposing a regional transmission solution to meet a regional transmission need, the region

¹⁹ State or local oversight also includes recognition of applicable FERC requirements, such as those of Order No. 890 (related to transmission planning), as well those of Order No. 693 (related to NERC reliability rules), in addition to other regional or local reliability rules.

²⁰ ColumbiaGrid is an exception. ColumbiaGrid does not prepare a baseline plan. Instead, ColumbiaGrid solicits recommendations for regional needs and evaluates transmission solutions proposed to meet these needs.

²¹ As noted previously, ColumbiaGrid is an exception because it does not prepare such a baseline plan.

evaluates the efficiency or cost-effectiveness of the proposed solution against local transmission projects in the baseline regional transmission plan that would be displaced by the proposed regional transmission solution because they also address the regional transmission need. An affirmative finding by the region that a proposed regional transmission solution is more efficient or cost-effective in addressing the regional transmission need than any local transmission projects in the baseline regional transmission plan would lead the region to select the proposed regional transmission solution in its regional transmission plan for purposes of cost allocation, making the transmission developer for this regional transmission project eligible to use the regional cost allocation method.²²

It is important to re-emphasize the assumption underlying the formulation of the baseline regional transmission plan. From the standpoint of the utilities within the region, it is already a regionally complete plan in that it jointly addresses the local transmission needs and solutions of each participating transmission provider in the region, as identified by the participating transmission provider. From the standpoint of a prospective transmission developer of a transmission project seeking to obtain regional cost allocation for their project, it is “the plan to beat.” That is, the transmission planning region’s role is to conduct a regional analysis to identify whether there are more efficient or cost-effective transmission solutions to regional transmission needs, whether sponsored by a prospective transmission developer or developed by the region (i.e., unsponsored), than transmission projects already contained in the baseline regional transmission plan. Seen in this light, the regional transmission planning process can be thought of as having been established primarily to provide an open, transparent means by which stakeholders are allowed to participate in regional transmission planning in an open, coordinated and transparent manner and non-incumbent transmission developers (and other stakeholders) can have their proposed solutions vetted against those of the incumbents whose projects are already contained in the baseline regional transmission plan. For example, while an incumbent transmission owner within a region can sponsor a regional transmission solution located outside of its footprint/service area, that owner would have to do so as a non-incumbent transmission developer.

In the non-ISO/RTO regions that use the sponsorship approach, the way the process is framed and sequenced means that sponsored regional transmission projects that have been proposed for regional cost allocation (as well as unsponsored regional transmission projects) can be thought of as alternatives to projects in the baseline plan in the region’s analysis of determining the more efficient or cost-effective transmission solutions to regional transmission needs. Put another way, regional transmission needs may be met through means that do not involve or require selection of transmission projects for regional cost allocation. From the standpoint of assessing how regional (and local) transmission needs are being met, these practices emphasize the importance of considering all transmission that is planned within a region, not just transmission projects that are selected in a regional transmission plan for purposes of cost allocation.

²² There are, however, limitations on eligibility. Consistent with applicable laws, which vary, state and local authorities must also provide the transmission project and its developer siting, permitting, and construction authorizations. More to the point, transmission projects that have not achieved a significant level of completion may be subject to suspension, revision, or even cancellation if doing so is determined appropriate in subsequent transmission planning cycles.

2.3 The Sponsorship Approach Used by ISO/RTO Regions

Some ISO/RTOs rely on a sponsorship approach for selecting transmission projects in their regional transmission plan for purposes of cost allocation. In this sub-section, we describe regional transmission needs and solutions in a generic fashion to focus on the phase within the transmission planning process at which the selection process is initiated. Section 3 of this report will provide more detail on the assessments of specific regional transmission needs (such as those driven by reliability needs, public policy requirements, or economic considerations) and how a transmission project might be found to meet them.

ISO/RTOs have primary responsibility for overseeing transmission planning for the higher-voltage transmission lines in their regions. The local transmission plans, if any, of the transmission owners within the ISO/RTO footprint provide input to ISO/RTO planning, but the ISO/RTO also conducts additional planning activities independently. In other words, while many of the non-ISO/RTO regions use their baseline regional transmission plans as a basis for regional transmission planning, the ISO/RTOs generally rely less on any local transmission plans to do so. Thus, ISO/RTOs have a much greater scope to conduct regional transmission planning than do the non-ISO/RTO regions.

Prior to FERC Order No. 1000, ISO/RTOs relied primarily on incumbent transmission owners to build the transmission projects identified in regional transmission plans. Some, but by no means all, of these transmission projects had their costs allocated regionally. That is, the ISO/RTO processes provide opportunities for meeting regional transmission needs with transmission solutions (including non-transmission alternatives) that do not receive regional cost allocation.

Several ISO/RTOs, perhaps best exemplified by NYISO, are explicit in providing opportunities for the “market” to first offer solutions (including transmission, generation, or demand response proposals) to meet regional transmission needs that will not require nor seek regional cost allocation. If such solutions are forthcoming, there is then no longer a need to conduct an open competitive process to select transmission projects in the regional transmission plan for purposes of cost allocation because the regional transmission needs have already been met by solutions whose revenue requirements are recovered via other means, such as through wholesale market mechanisms or bi-lateral contracting arrangements. In this setting, the formal process for selecting transmission projects to meet regional transmission needs (and become eligible for regional cost allocation) can be thought of as a “last resort,” after other means have been considered that might meet these needs. In other words, in these regions, reliance on a sponsorship approach to select transmission projects in the regional transmission plan for purposes of cost allocation is an outcome of having first considered other avenues for ensuring that regional transmission needs are met. The sponsorship approach in these regions rewards developers (either non-incumbent or incumbent) for their creativity in proposing transmission projects that will meet remaining, unmet regional transmission needs.

2.4 Similarities and Differences between Competitive Bidding and Sponsorship Approaches

Based on the background laid out in the preceding sections, the competitive bidding approach can be seen as a variation within the overall two-stage transmission planning process (that is, confirmation of regional needs for transmission, followed by evaluation of transmission solutions that might meet these needs more efficiently or cost-effectively than alternatives) that can but does not always lead to selection of transmission projects in the regional transmission plan for purposes of cost allocation. In this regard, it is not fundamentally different from the sponsorship approach pursued in other ISO/RTO regions. That is, both types of regions provide opportunities for stakeholders, including prospective transmission developers, to propose transmission solutions to meet regional transmission needs. All regions provide means for vetting and evaluating these solutions. As discussed, some of these solutions will be implemented in ways that do not require or lead to selection of a transmission project in the regional transmission plan for purposes of cost allocation.²³ As a result, some, if not all, regional transmission needs may be satisfied by these means. Furthermore, as a practical matter, only qualified developers can develop transmission projects that have been selected in a regional transmission plan for purposes of cost allocation.²⁴

Where the competitive bidding approach differs from the sponsorship approach is in the formal separation between the process for confirming that a regional transmission solution is more efficient or cost-effective than alternatives in meeting a regional transmission need and the process for selecting a developer for this solution. In a sponsorship approach, selection of a regional transmission solution and a developer for it takes place in a single step. In a competitive bidding approach, selection of a regional transmission solution is a separate and distinct process that precedes the process for selecting a developer for the solution. Bear in mind that, even in the sponsorship approach, the regional transmission solution that is selected may and often does reflect substantial input from stakeholders and the planning staffs of the regions.

Some regional transmission planning processes that rely on the competitive bidding approach provide a “credit” to developers that participate in the process of identifying transmission solutions. The credit increases the score that the developer’s proposal receives during the subsequent open competitive selection process. This credit can be viewed as rewarding the developer for contributing its transmission project ideas to the initial process of identifying and evaluating transmission solutions. In this sense, when a specific transmission solution emerges—which in turn leads to a competition to select a developer—the developer’s contribution to the formulation of that solution is rewarded in a manner that is similar in spirit to the selection of a developer’s project—albeit potentially modified from the developer’s initial proposal through the region’s vetting processes—under the sponsorship approach.

²³ FERC concluded that the issue of cost recovery for non-transmission alternatives was beyond the scope of transmission cost allocation reforms that it would adopt in Order No. 1000. Consequently, non-transmission alternatives are not permitted to be selected in a regional transmission plan for purposes of cost allocation nor allocated through the Order No. 1000 cost allocation methods.

²⁴ In principle, the iterative nature of regional transmission planning processes provides a means by which meritorious suggestions from stakeholders in one transmission planning cycle can be picked up and “sponsored” by a prospective developer in a subsequent transmission planning cycle.

2.5 Summary

This section has described how the regions frame or structure the overall transmission planning processes within which transmission projects may be selected in a regional transmission plan for purposes of cost allocation. It has described the differences in overall transmission planning approaches conducted by ISO/RTO regions and non-ISO/RTO regions. It has used this framing to describe differences between what have come to be called the sponsorship and competitive bidding approaches for selecting developers for regional transmission solutions.

In most non-ISO/RTO regions, the participating utilities' individual transmission plans are combined to form a baseline regional transmission plan.²⁵ The baseline regional transmission plan is then used to evaluate proposals from stakeholders and prospective transmission developers for both regional transmission needs and regional transmission solutions (including non-transmission alternatives²⁶) that will meet these needs on what is essentially a need-by-need and project-by-project basis. The non-ISO/RTO regions generally use a *sponsorship* approach that both selects a regional transmission project and a developer for that project, which is then also eligible for regional cost allocation.²⁷

In the ISO/RTO regions, the ISO/RTOs have responsibilities for a much broader scope of transmission planning (e.g., for all of the highest-voltage transmission lines within their respective regions) than the non-ISO/RTO regions. As a result, there is less of a role for a separate, initial baseline regional transmission plan. In ISO/RTO regions that rely on a sponsorship approach, the selection of a regional transmission solution is closely tied to the selection of a qualified developer. In ISO/RTO regions that rely on a competitive bidding approach, the selection of regional transmission solutions is a largely distinct process from the selection of a qualified developer.

Both ISO/RTO and non-ISO/RTO regions can and do find that their regional transmission needs may be met by means that do not involve or require selection of transmission projects whose cost may be allocated regionally pursuant to an Order No. 1000 regional cost allocation method. Consequently, in assessing how regions meet their regional transmission needs, it is important to consider how *all* transmission projects are planned within a region, not just transmission projects that have been selected in a regional transmission plan for purposes of cost allocation. That is, while a region may not identify any more efficient or cost-effective regional transmission solutions and, therefore, not select any transmission projects for regional cost allocation, it has an obligation to assess whether there are more efficient or cost-effective regional transmission solutions—even if the needs would otherwise be met through local transmission facilities.

²⁵ ColumbiaGrid is an exception; ColumbiaGrid does not develop an initial baseline regional transmission plan.

²⁶ FERC concluded that the issue of cost recovery for non-transmission alternatives was beyond the scope of transmission cost allocation reforms that it would adopt in Order No. 1000.

²⁷ WestConnect is an exception; WestConnect uses a competitive bidding approach.

3. Assessing Regional Transmission Needs

This section describes how specific regional transmission needs—those driven by reliability requirements, public policy requirements, and economic considerations—are assessed by the transmission planning regions, including how these assessments are sequenced with respect to one another, and how the standard for regional cost allocation—finding that a regional transmission solution is more efficient or cost-effective than alternatives—is applied. We extend basic descriptions provided in Eto 2016 by locating these assessments within the larger set of transmission planning processes that take place within regions, as outlined in Section 2 of this report. This section begins by reviewing the oldest of the transmission needs formally assessed by regions, reliability requirements, which is generally addressed at the front end of a regional transmission planning cycle and often includes elements that take place prior to or outside the planning cycle. We next discuss the newest of the assessments, of transmission needs driven by public policy requirements, which must follow formal procedural requirements directed by FERC Order No. 1000. We then turn to economic planning studies, including assessments of transmission needs driven by economic considerations, which involves determining the need for potential investments that could reduce congestion costs or integrate new resources and loads on an aggregated or regional basis. Finally, we review how regions assess and determine whether a regional transmission solution is more efficient or cost-effective than alternatives for meeting one or more of these regional transmission needs.

3.1 Transmission Needs Driven by Reliability Requirements

The need to ensure power system reliability has always been a formal driver of transmission planning. Knowing how each region manages compliance with mandatory reliability rules helps us understand the structure or framing of the regional transmission planning approaches described in Section 2. It also helps to explain why assessments of reliability-driven transmission needs tend to take place at the front end of—or even prior to and, in this sense, “outside” of—a regional transmission planning cycle, which, in turn, is important for understanding how subsequent assessments are conducted. Finally, this subsection describes how the need to ensure reliability helps justify selecting certain transmission projects in a regional transmission plan for purposes of cost allocation that will be developed by the incumbent transmission operator(s) instead of by developers selected through an open, competitive process.

Formal responsibilities for transmission planning to ensure reliability are spelled out in North American Reliability Corporation (NERC), regional, and local reliability rules and standards. Transmission Planners, which is a formal title that requires registration with NERC, are responsible for assessing the longer-term reliability of Transmission Planning areas. Transmission Planners are supported by Planning Coordinators, which is another formal title that requires registration with NERC. Among these entities’ responsibilities is a requirement to conduct, annually, both very short-term (one to two years ahead) and near-term (five years ahead) transmission reliability planning studies. These responsibilities and the planning activities they require underpin and are incorporated in various ways into the regional transmission planning activities directed by FERC Order Nos. 890 and 1000.

In non-ISO/RTO regions, reliability transmission planning is managed independently by the utilities that have been designated Transmission Planners. This includes some utilities that have also been designated Planning Coordinators for one or more Transmission Planners. These transmission planning activities, which include regional and interregional activities, are wholly independent of and, in effect, take place “outside of” and “prior to” the planning activities led, per FERC Order Nos. 890 and 1000, by the transmission planning region.

The fact that utilities have these responsibilities is the reason that, as described in Section 2, the combined local transmission plans of the participating utilities within a region can be understood to represent a complete transmission plan for addressing the reliability needs of each individual utility in the region. It also helps explain why prospective regional alternatives (i.e., transmission projects that seek regional cost allocation) are evaluated against the transmission projects in the combined transmission plan, as potential replacements for the projects that are already contained in the combined plan. Accordingly, the initial vetting of these regional transmission project alternatives involves finding that they would meet applicable reliability rules and standards in a way that is equivalent to the compliance with reliability rules of the local transmission projects that the regional transmission project alternatives might displace.

Some non-ISO/RTO regions conduct independent reliability planning studies that start with the combined local transmission plans of participating utilities. NTTG, SC RTP, and SERTP, for example, evaluate regional alternatives that might replace one or more local transmission projects within the combined local transmission plans. NTTG makes an assessment that sometimes re-evaluates non-committed transmission projects (which have been selected in the prior regional transmission plan) against the proposed regional alternatives.²⁸ ColumbiaGrid and WestConnect independently assess whether there are reliability issues that might affect more than one participating utility.

Bear in mind that, in all of these regions, the transmission planning region is generally not a NERC-designated entity with formal responsibility for reliability transmission planning.²⁹ These responsibilities continue to be held by the Transmission Planners and Planning Coordinators within the region, not by the transmission planning region. See Figure 3.

The above situation contrasts with that in the regions where ISO/RTOs formally lead regional reliability transmission planning. The ISO/RTOs are generally Planning Coordinators if not also Transmission Planners for transmission facilities within their footprints. In some instances, they share Transmission Planner responsibilities with transmission-owning utilities within their footprints. For example, the ISO/RTO may be the Transmission Planner for most or all of the highest-voltage lines in the region while

²⁸ Preparation of NTTG’s regional transmission plan involves first identifying a base plan that includes existing and future (committed and non-committed) transmission projects from the local transmission plans and NTTG’s prior regional transmission plan. Non-committed projects are ones for which rights-of-way or permits have yet to be secured and are subject to re-evaluation.

²⁹ FRCC is an exception. FRCC is a NERC Regional Entity as well as a registered Planning Coordinator with a coordinated functional registration with the Transmission Planners within its footprint. FRCC’s activities as a NERC Regional Entity are conducted as a separate function from its FERC transmission planning region activities and other reliability planning functions.

the transmission-owning utilities are Transmission Planners for the lower-voltage lines. In other instances, the ISO/RTO is the sole or primary Transmission Planner for most or all of the transmission facilities within its footprint. In both instances, the ISO/RTO, as the Planning Coordinator, has substantive responsibility for transmission planning to ensure reliability, which differs fundamentally from the responsibility of the transmission planning regions that are not designated by NERC as reliability transmission planning entities.

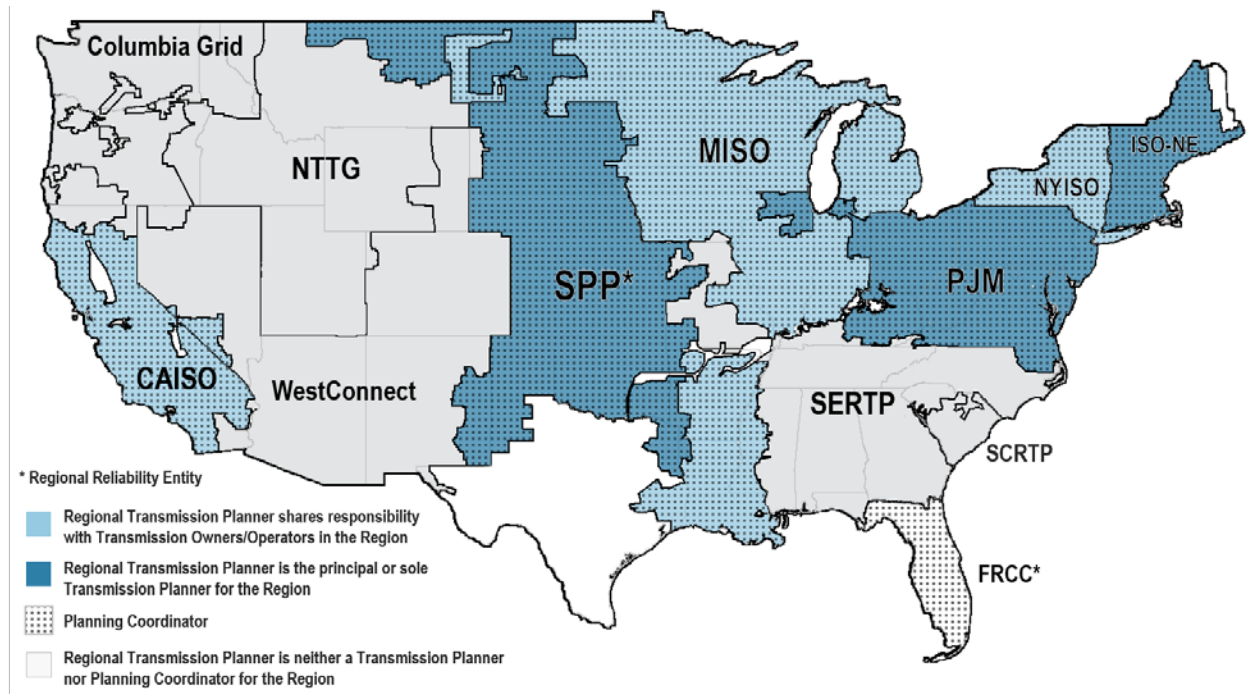


Figure 3. NERC Registration for Reliability Planning Functions

The formal, NERC-registered transmission reliability planning responsibilities of ISO/RTOs helps to explain why reliability assessments also tend to take place early in the cycle of ISO/RTOs' regional transmission planning. Although these regional entities may, at the end of a regional transmission planning cycle, find that transmission solutions are appropriate for meeting public-policy requirement or economics-driven transmission needs, these entities must, as a mandatory requirement, find that the transmission system they operate has been planned in compliance with mandatory NERC, regional, and local reliability rules. To make these findings, ISO/RTOs must first take into account the individual local transmission plans of the transmission owners within the region when they also have formal reliability planning responsibilities as NERC-registered planning entities. Thus, consideration of public-policy requirement or economics-driven needs for transmission by these regions will tend to follow and, indeed, often is based on transmission plans that are initially intended specifically to meet reliability-driven transmission needs.

Table 1. Characteristics of New Transmission Facilities that may be Eligible for Regional Cost Allocation

	Minimum physical requirements	Reliability-driven circumstances that may not require open competitive selection process
California ISO (CAISO)	$\geq 200\text{kV}^*$ $< 200\text{kV}$ if located in more than one retail distribution service territory or footprint	None – all new projects that seek regional cost allocation must be selected through an open, competitive process
ColumbiaGrid	None	None – as above
Florida Reliability Coordinating Council (FRCC)	$\geq 230\text{kV}$ ≥ 15 miles Materially different from projects already in regional transmission plan	None – as above
ISO New England (ISO-NE)	$\geq 115\text{kV}$	Projects required to meet reliability needs within next 3 years (except when a market efficiency transmission upgrade is likely a solution)
Midcontinent ISO (MISO)	Market Efficiency $\geq \$5\text{M}$ cost $\geq 345\text{kV}$ $>100\text{kV}$ if less than 50% of the project and needed for $\geq 345\text{kV}$ transmission facilities	None – as above
New York ISO (NYISO)	Multi Value $\geq \$20\text{M}$ cost $\geq 100\text{kV}$ Generally $> 200\text{kV}$ Economic Projects: $\geq \$25\text{M}$ cost	None – as above
Northern Tier Transmission Group (NTTG)	$\geq \$20\text{M}$	None – as above
PJM Interconnection (PJM)	Reliability and Economic Regional Facilities $\geq \$5\text{M}$ cost $\geq 345\text{ kV}$ double circuit $\geq 500\text{ kV}$ single circuit	Projects required to meet reliability needs within next 3 years
South Carolina Regional Transmission Planning (SCRTP)	$\geq 230\text{kV}$ Materially different from projects already in the regional plan	None – as above
Southeastern Regional Transmission Planning (SERTP)	$>300\text{kV}$ ≥ 50 miles	None – as above
Southwest Power Pool (SPP)	Highway $\geq \$100\text{k}$ cost $\geq 300\text{kV}$ Byway $\geq \$100\text{k}$ cost 100 - 300kV	Projects required to meet reliability needs within next 3 years
WestConnect	None	None – as above

*kV – kilovolt

To help ensure reliability, some ISO/RTO regions (ISO-NE, PJM, and SPP) have FERC-approved provisions that address transmission projects that are required imminently to meet reliability needs (e.g., the reliability issue must be addressed within the next three years). If certain conditions are met, the provisions exempt the region from conducting a competitive transmission development process for such an “immediate-need reliability project,” assigning the projects to the incumbent transmission owner, and permitting the incumbent transmission owner to seek regional cost allocation. See Table 1.

3.2 Transmission Needs Driven by Public Policy Requirements

The need to address public policy requirements is a comparatively new driver for transmission planning. FERC Order No. 1000 directs regions to formally consider transmission needs driven by public policy requirements and to establish open, competitive regional transmission planning processes through which transmission projects may be selected to meet these needs (and thereby become eligible to have their cost allocated regionally). This subsection describes how consideration of these transmission needs and selection of transmission projects take place within and are related to other assessments that are conducted during regional transmission planning cycles. We also describe how some of these activities interact with or are informed by state-level public policy requirements.

We focus first on the practices of the non-ISO/RTO regions, which reveal many of the basic structural features and sequencing of all regional processes for addressing transmission needs driven by public policy requirements. As noted in Section 2, the combined local transmission plans of the participating utilities in these regions are deemed, from the onset, to be complete in addressing the region’s local public policy requirement-driven needs.³⁰ That is, it is recognized, in state or local integrated resource-planning activities, that these needs have been given due consideration and are reflected in the plans that emerge from those activities.

Thus, in these regions, a principal focus of regional transmission planning is to provide a regional forum for additional consideration of transmission needs driven by public policy requirements. Typically, the regional transmission planning cycle will feature an open-window period during which stakeholders, including developers, have an opportunity to suggest regional needs for transmission to address public policy requirements. The region must then make findings regarding whether to plan for a proposed transmission need driven by those requirements. Generally speaking, the basis upon which such findings have been made in practice have pointed back to the state and local decision-making processes that led to the approvals for the original local transmission plans.

If the region confirms that there is a need for transmission driven by public policy requirements that should be evaluated for potential solutions in the regional transmission planning process, it would then begin the evaluation process to determine how those transmission needs might be met, including whether a regional transmission solution (either proposed by qualified transmission developers,

³⁰ As noted previously, ColumbiaGrid does not formally “combine” local transmission plans, nor deem these plans, taken together, as regionally complete from the standpoint of addressing local transmission needs that might be driven by public policy requirements.

stakeholders, or identified by the region) is more efficient or cost-effective than alternatives in meeting the need. The means and pathways by which these assessments are made vary; they are spelled out in specific tariff language of each of the participating planning utilities in their tariff filings with FERC.

In the ISO/RTO regions, the basic outlines of the transmission planning processes are very similar. That is, first, transmission needs driven by public policy requirements must be identified. And, second, if needs are identified, the regions will evaluate transmission needs for which transmission solutions will be evaluated. However, the identification of transmission needs, the ways in which they are assessed, and, in particular, how these assessments interact with other transmission projects that are being considered in the regional transmission planning process differ, sometimes considerably, from how these steps are taken in the non-ISO/RTO regions.

Similar to the processes followed in non-ISO/RTO regions, the open-window processes through which the ISO/RTO regions consider transmission needs driven by public policy requirements focus initially on identifying the requirements that will be considered. Then, at a later stage, the RTO/ISO regions consider the question of whether a regional transmission solution is required to meet these requirements (i.e., whether a “transmission need” exists). And, similarly, both types of regions make explicit reference to existing national, state, and local laws and regulations in conducting their needs assessments.

However, several ISO/RTO processes include explicit interaction with state-level bodies in determining which (for example, state-level) transmission needs driven by public policy requirements are appropriate for consideration in the regional transmission planning process. NYISO, for example, relies on a formal determination made by the New York Department of Public Service (NYDPS) regarding which public policy requirements will be considered in the regional transmission planning process. NYDPS may direct NYISO to consider public policy requirements that it has identified independent of and in addition to suggestions by stakeholders. Other ISO/RTO regions feature similar, explicit roles or means for addressing information and opinions submitted by regional organizations of state regulatory bodies. This includes New England States Committee on Electricity (NESCOE) for ISO-NE, the Organization of MISO States for MISO, and the Organization of PJM States and the PJM Independent State Agencies Committee both for PJM.

In addition, because ISO/RTO regions have direct responsibilities to plan for all higher voltage lines across their region (in contrast, to non-ISO/RTO regions, in which the participating public utility transmission providers have independent responsibilities to plan for these lines within their footprints), the evaluation of transmission solutions to meet transmission needs driven by public policy requirements may be, to an extent, viewed as more interactive with evaluations of transmission solutions that meet other regional transmission needs. For example, if transmission needs to address reliability requirements have led to identification of transmission solutions (whether or not they are found to be regional solutions) to meet them, these solutions would be taken into account when assessing whether additional transmission solutions are needed to meet identified needs driven by

public policy requirements. If so, the evaluation of additional transmission solutions would focus on only whether another alternative could meet these needs more efficiently or cost effectively.

For example, transmission developers that propose transmission solutions that meet regional transmission needs but which elect not to seek regional cost allocation may also emerge through the regional transmission planning process. The regional transmission planning process may also find that these projects also address transmission needs driven by public policy requirements. As a result, the region may also determine that no additional transmission solutions are required to meet regional transmission needs driven by public policy requirements.

3.3 Economic Planning Studies and Transmission Needs Driven by Economic Considerations

Regional economic transmission planning involves considering whether potential investments could reduce congestion or integrate new resources on a regional basis. FERC Order No. 890 requires that all public utility transmission providers conduct economic planning studies, and Order No. 1000 extended this requirement to regional transmission planning processes. These studies are therefore a core, routine element of the transmission planning activities in both each public utility transmission provider's local transmission planning process and, with the implementation of Order No. 1000, each region's processes for evaluating whether to select a proposed transmission solution in its regional transmission plan for purposes of cost allocation to address a regional economic need, which is discussed in the next sub-section.

In reviewing the economic planning activities conducted by the regions, it is useful to distinguish between the regions that conduct economic planning studies mainly to inform market participants about potential regional transmission investments once regional transmission needs driven by economic considerations have already been determined by the region, and those that conduct studies that lead to formal findings regarding regional transmission needs driven by economic considerations.

SCRTP and SERTP perform economic planning studies that are intended mainly to inform market participants who might propose and/or sponsor alternatives. The rationale and conduct of these studies is consistent with the overall approach to transmission planning taken in these regions. This involves assembling an initial baseline regional transmission plan from the local transmission plans of participating incumbent transmission owners and then evaluating alternatives proposed by stakeholders and non-incumbent developers. The studies conducted annually by SERTP and SCRTP analyze costs of the transmission enhancements that would be required to accommodate hypothetical increased transfers suggested by stakeholders. In addition, through a distinct yet closely related annual study process, SERTP also analyzes the cost of hypothetical (including stakeholder-suggested) regional transmission projects compared to the cost of projects contained in the baseline regional transmission plan that the hypothetical projects might displace. (See Figure 4.)

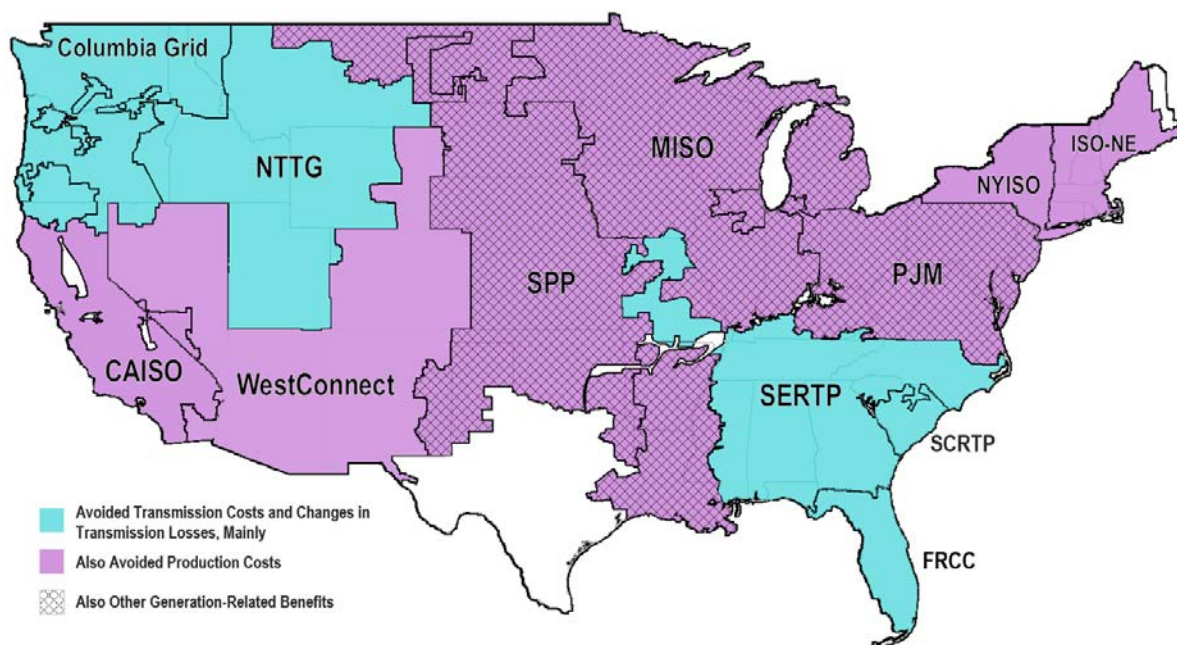


Figure 4. Factors Considered in Evaluating the Economic Impacts of Transmission Solutions in Planning Studies

All of the ISO/RTO regions, as well as ColumbiaGrid, NTTG, and WestConnect, conduct studies that lead to a formal finding regarding regional transmission needs driven by economic considerations. These regions use various approaches to assess economic congestion on their systems. MISO, NYISO, PJM, and SPP, for example, identify areas to be studied by formally tabulating areas experiencing significant congestion. Other regions rely on a stakeholder-driven process to identify areas for study. Some regions limit the number of areas that are studied in a given transmission planning cycle, as a practical consideration. A principal purpose served by these economic planning studies is, as in the studies conducted by SC RTP and SERTP, to inform stakeholders and developers.

Generally speaking, these studies compare the cost of hypothetical transmission solutions (including non-transmission alternatives) to relieve areas experiencing congestion to the economic value of the relief that might be provided. Typically, they involve the use of simulation-based modeling tools that estimate total generation production costs within a region, given a fixed transmission topology. Approaches based on production cost simulations compare the economic impacts of changes in generation dispatch enabled by the transmission project to the cost of the project itself.³¹ Two simulations are conducted: one with and the other without the transmission solution(s) under consideration. The difference in the total cost of production under the two simulations is credited as the economic benefit of the transmission solution.

This formulation of the economic benefits of transmission solutions is in contrast to that considered in the studies conducted by SC RTP and SERTP, which focus primarily on the comparative (i.e., “avoided”)

³¹ Sometimes the capital costs are annualized and compared to annualized production cost savings; sometimes total capital costs are compared to life cycle production cost savings.

transmission-related costs of alternatives. Note, however, that changes in transmission losses are generally also considered. When transmission losses are reduced, the value of these reductions is an economic benefit provided by the alternative.

Some regions also evaluate other generation-related benefits. PJM evaluates energy-market benefits for high-voltage regional transmission projects. These benefits comprise 50% of the total production cost savings plus 50% of the change in load energy payments.³² SPP considers a number of economic impacts in addition to changes in production costs, including: (1) reduction of emissions rates; (2) savings from reduced ancillary service needs; (3) avoided or delayed reliability projects; (4) capacity cost savings from changes in on-peak transmission losses; (5) assumed benefits of mandated reliability projects; (6) public-policy benefits; (7) increased “wheeling through and out” revenues; (8) marginal energy loss benefits; and (9) mitigation of transmission outage costs.

As with the assessment of reliability and public policy driven needs, the transmission solutions may be suggested by stakeholders or prospective developers; in some instances, they may be developed by staff independently with input from stakeholders. Similarly, a finding of economic transmission need for a transmission project (e.g., to relieve congestion) may, in turn, lead to the selection of one or more transmission projects in the regional transmission plan for purposes of cost allocation.

Some of the regions develop and evaluate alternative scenarios and/or conduct sensitivity analyses in preparing their economic planning studies. These approaches are undertaken to assess the robustness of their studies’ findings.

3.4 Determination of a Transmission Solutions’ Efficiency or Cost-Effectiveness Compared to Alternatives

FERC Order No. 1000 requires that, to select a transmission project in a regional transmission plan for purposes of cost allocation, a region must make an affirmative finding that the project is more efficient or cost-effective than alternatives. To establish sufficient net benefits to select a transmission project for regional cost allocation, FERC Order No. 1000 provided the transmission planning regions the latitude to require that the benefits exceed the estimated costs by at least 25%, which some but not all regions have adopted.

All regions have developed formal approaches to evaluate whether to select a proposed transmission project to implement these requirements. Some non-RTO/ISO regions consider aspects of transmission-related cost savings that would be avoided or displaced by a regional transmission solution compared to alternatives for evaluating potential reliability and economic regional transmission projects. These costs generally include capital-related costs. In addition to these “avoided costs,” they also consider the value of changes in transmission losses.³³

³² Similarly, in PJM, capacity market benefits for high-voltage regional transmission projects comprise 50% of the change in total system capacity costs plus 50% of the change in load-capacity payments.

³³ NTTG also considers the value of changes in reserve requirements.

Approaches based on so-called avoided costs, such as these, arise naturally from and are reflective of the formulation or structure of the regional transmission planning process in many of the non-ISO/RTO regions. These approaches compare the costs associated with a potential regional transmission project to the costs associated with the project(s) in the baseline regional transmission plan that would be displaced.

The logic behind this approach can also be seen when, for example, a region evaluates competing regional solutions to meet a given regional reliability-driven transmission need. That is, each regional solution must, in order to be considered, be found to ensure that the region will meet the same reliability requirements. As an extreme example to emphasize this concept, if the reliability “benefit” is identical for all solutions under consideration to meet a given need, then the only differentiator among alternatives from the standpoint of efficiency or cost-effectiveness is their comparative costs with respect to one another. The least expensive alternative, therefore, is the more efficient or cost-effective one compared to these alternatives. In fact, it is more common for alternative solutions to also vary in terms of the benefits they provide (such as greater or lower transmission losses).

As noted in discussing transmission needs driven by regional economic considerations, some regions (both ISO/RTO and some non-ISO/RTO) consider generation-related impacts of transmission solutions and these considerations are included to varying degrees when these regions evaluate the efficiency or cost-effectiveness of potential regional solutions. The most common approach to estimating these impacts, as noted, involves the use of iterative production cost simulations of the region with and without inclusion of the regional solution under consideration.

MISO’s process for evaluating Multi-Value Projects for selection in the regional transmission plan for purposes of cost allocation is unique among the regions in several ways.³⁴ First, Multi-Value Projects are evaluated as part of a portfolio of projects, as designated in the MISO transmission expansion planning process; the benefits of these projects are spread broadly across the MISO footprint. Evaluation criteria are applied to both individual transmission projects and all transmission projects taken together. All other regions typically evaluate efficiency or cost-effectiveness only on a project-by-project basis. Second, MISO’s process articulates multiple scenarios that are used to evaluate the portfolio of transmission projects. The evaluation involves a formal numerical weighting of individual scenario outcomes to develop an overall finding of efficiency or cost-effectiveness based on the composite weighted score of the entire portfolio. MISO applies its evaluation criteria (benefits exceed costs by 25% or more) to the portfolio, not to individual transmission projects. Consideration of transmission projects together in a portfolio is the principal means by which MISO incorporates and evaluates transmission needs that are driven by public policy requirements.

Several regions also conduct scenario analyses, but they do not formally integrate or combine the results from all scenarios in evaluating whether to select a proposed transmission solution in the regional transmission plan for purposes of cost allocation. Instead, they rely on a single, base scenario

³⁴ In fact, SPP’s Balanced Portfolio approach share similarities with MISO Multi-Value Projects approach.

as the source of their numerical findings. The results from the additional scenarios or sensitivities that are considered are presented as supporting information because these scenarios are considered prior to evaluating whether to select a proposed transmission solution in the regional transmission plan for purposes of cost allocation.

PJM’s Multi-Driver Process allows transmission solutions emerging from different planning analysis streams, such as reliability, to be enhanced or modified to address additional drivers, such as public policy requirements. In doing so, the process also provides a means for explicitly allocating the costs of the solutions in close alignment with their drivers.

3.5 Summary

This section has described how specific regional needs for transmission—*reliability*, *public policy requirements*, and *economic*—are assessed by the transmission planning entities, how these assessments are sequenced, and how the standard of “more efficient or cost-effective” is applied.

Transmission needs driven by reliability requirements have the longest history of being formally evaluated by regions, and are generally considered at the start of (and even prior to or outside of) a regional transmission planning cycle. Where and how reliability-driven transmission needs are addressed in relation to a regional transmission planning process depends on whether and to what extent the transmission planning region itself is responsible for complying with mandatory national, regional, and local reliability rules. Regions that assume responsibility for this compliance must first take into account the findings of the NERC-registered entities that are responsible for compliance with applicable reliability planning standards. Regions that are responsible for this compliance must make findings that their planned transmission facilities will comply with these rules, independent of findings they make regarding regional cost allocation for specific projects. The “more efficient or cost-effective” standard generally focuses on whether the cost of a regional solution is lower than the cost of an alternative or the reliability benefits of a regional solution are greater than those of alternatives (often in the form of reduced transmission losses). The alternative could be either another proposed regional solution or a set of local solutions (e.g., those that together would involve more than one transmission owner’s footprint within the region).

Transmission needs driven by public-policy are those that address public policies established by local, state, or federal laws or regulations. This category of transmission needs was the one most recently added to the list of needs that public utility transmission providers are required to assess. These assessments, which must be conducted periodically, tend to follow after an assessment of reliability-driven needs and potential regional transmission solutions, though they are also sometimes conducted in parallel or jointly with other needs assessments. The assessment processes follow common steps in all regions. First, the regions determine whether and what public policy requirements create needs for a regional transmission solution(s). Stakeholders, including states, within all regions have an important role in the identification of public policy requirements which might create these needs. In some ISO/RTO regions, there are formal arrangements with either a single state PUC (for single-state

ISO/RTOs, such as CAISO and NYISO) or standing committee of PUCs to identify these needs. Then, separately or jointly with the identification of transmission needs, they consider proposals for regional solutions that might meet them. The basic test remains whether a regional transmission solution will meet these needs more efficiently or cost-effectively than alternatives. The alternatives, again, may be either other regional solutions or local solutions that the regional transmission solution might displace/replace.

Transmission needs driven by economics are needs associated with reducing congestion costs or integrating efficient new resources and new or growing loads. These needs assessments are sometimes conducted after other regional needs assessments have been completed, but are sometimes conducted in parallel or jointly with the other needs assessments. There are two basic approaches for evaluating the economic benefits of projects; each is generally aligned with the type of region. In most non-ISO/RTO regions, the economic benefit of a regional transmission solution is determined by considering, among other benefits such as changes in transmission losses, the costs of the local transmission projects that would be replaced (or “avoided”) by a regional solution. In all ISO/RTO and some non-ISO regions, the economic benefit of a regional transmission solution is determined by also considering regional changes in production costs (sometimes along with other generation-related impacts) that would result from the construction and operation of a proposed solution. These approaches translate in spirit but to varying degrees to the means by which the “more efficient or cost-effective” standard is subsequently (and separately) applied by these regions to evaluate regional solutions that might meet these needs.

4. Reviewing Regional Transmission Planning Outcomes and Processes

This section draws upon the information presented in Sections 2 and 3 to discuss aspects of the regional transmission planning outcomes and processes that should be reviewed and evaluated over time, with a focus on current publicly available sources of information to support these assessments.

4.1 Transmission Projects

Eto 2016 emphasized the importance of tracking transmission projects selected in a regional transmission plan for purposes of cost allocation while recognizing that some regions will find either that there are no regional transmission needs or, if there are such needs, that there are no regional transmission solutions, which are more efficient or cost-effective than alternatives. This report has expanded upon this recognition to emphasize that one of the reasons why regions reach the latter conclusion is that they have determined that their regional transmission needs will be met by means other than a regional transmission solution. These might include merchant transmission projects, participant-funded projects, non-transmission alternatives, or local transmission facilities. So, while transmission projects selected for regional cost allocation remain a critical outcome of regional transmission processes and, therefore, should be tracked, they are not the only—and may not be the most important—outcomes that should be tracked.

Assessing how regions are meeting their regional transmission needs requires an inclusive approach. This means considering all transmission (and non-transmission) solutions emerging from within (or as a part of) the regional transmission planning processes described in this report, a likely majority of which neither would qualify for or, if qualified, might not seek regional cost allocation (e.g., non-transmission solutions are not eligible for regional cost allocation). It also means, in many regions, considering transmission projects that are being developed external to or independent of regional transmission planning processes and, therefore which would not be considered as a potential regional transmission solution (such as merchant transmission projects). In this regard, it also means understanding how non-transmission solutions (such as energy efficiency and generation) may be addressing regional transmission needs and, thereby, affecting the efficiency or cost-effectiveness of transmission projects that are being considered for selection in a regional transmission plan for purposes of cost allocation.

The information required to inform these assessments is, by and large, already publicly available, either from the transmission planning regions, themselves, other public forums associated with planning that takes place independent of the regions (e.g., state PUC proceedings), or still other sources (e.g., national data sources, such as the Energy Information Administration). The challenge that arises in assessing transmission outcomes on such an inclusive basis, however, is that publicly available sources, such as these, generally did not envision and hence have not been designed or organized in ways that readily support these assessments.

For example, current national data-collection activities were not designed to support tracking transmission projects with a view toward understanding, in detail, how regions—as identified by FERC through Order No. 1000—are planning and meeting their transmission needs. FERC Form 1³⁵ and EIA Form 411³⁶ collect information annually from all utilities on transmission spending and construction. In this sense, these forms are completed, meaning that they include information on all transmission activities (albeit that the focus of both forms is only on the most recent year of activity). The information collected, especially as relates to the finances of transmission, however, is aggregated for each utility as a whole. The forms do not document financial information on individual transmission projects. The only information collected on individual transmission projects is on the physical characteristics of the facilities.

As a measure of the current state of the transmission system, the value of information collected via these existing means is not in question. However, neither form collects information on planned transmission; therefore, these forms are of limited value in assessing regional transmission planning activities. This is not a criticism of the forms or a suggestion that they should be modified but rather a reminder that these forms, which comprise the only federal data gathering related to transmission, were not designed to track the outcomes from regional transmission planning activities. However, if other means for gathering this information are not forthcoming, it could be appropriate to consider revisions to these forms provided that the benefits of doing so exceed the additional administrative and cost burdens that would be involved. In addition, protections may be required in order to ensure appropriate treatment of proprietary and financially or competitively sensitive information.

NERC, through the regional reliability entities, collects and publishes information annually on transmission, including planned projects. This information is national in scope. Notably, NERC collects information on transmission over several time frames. This includes transmission currently under construction, planned transmission five years in the future, and planned transmission 10 years in the future.³⁷ The future projections of planned transmission distinguish between two types of transmission: “expected” and “conceptual.” The information is aggregated and reported according to regional boundaries (some of which have changed over time).

However, there are limits to the usefulness of this information for assessing the regional (and sub-regional) transmission planning activities described in this report. First, the definition of what is counted as expected planned transmission and what is counted as conceptual planned transmission may or may not correspond to the definitions used in regional transmission planning processes. Second, the boundaries of the regional reliability entities do not all correspond to the boundaries of the 12 transmission planning regions, so planned transmission, as aggregated through NERC, cannot be linked to the transmission planning regions (and planning regimes) from which they emerge. Third, as will be discussed further in the next sub-section, NERC and the regional reliability entities do not collect cost

³⁵ See <https://www.ferc.gov/docs-filing/forms/form-1/viewer-instruct.asp>

³⁶ See <https://www.eia.gov/electricity/data/eia411/>

³⁷ See the NERC Electricity Supply & Demand Database (ES&D) at <http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx>.

information related to transmission currently under construction or planned. As above, these observations are not criticisms. They are, however, a reminder that the information collected by NERC is, understandably, oriented toward and organized from the perspective of reporting on how reliability needs are being addressed. This information is not oriented toward supporting assessments of the regional transmission planning activities reviewed in this report.

As an aside, related to the focus of NERC's reliability-data-collection activities, adopting an inclusive or holistic approach also means that care must be taken to not label transmission projects too finely. Many regional transmission planning processes provide explicit pathways by which transmission projects proposed initially to meet reliability transmission needs may be found (either as is or with modification) to also meet economic-driven needs or needs driven by public policy requirements. PJM's Multi-Driver process, for example, provides an explicit means for allocating project costs to distinct drivers. MISO's Multi-Value process assesses efficiency and cost-effectiveness of multiple transmission projects taken together in a single portfolio. The individual projects within the portfolio may address more than one transmission need. In these instances, categorizing transmission projects as, for example, strictly meeting reliability needs rather than transmission needs driven by public-policy requirements will not be particularly meaningful.

Although there is the possibility that existing sources of regional information can be relied on to support the monitoring described in this sub-section, there are limitations to current regional sources as well. For example, all transmission planning regions can be expected to report information on transmission projects selected in the regional transmission plan for purposes of cost allocation. Thus, they could, in principle, collect and organize information in ways that would support a comprehensive view of transmission planning activities within their regions. However, all currently report on a narrower scope of activities.

For example, ISO/RTO regions, consistent with their additional planning responsibilities, report information on transmission projects emerging through their related transmission planning processes, only some of which involve or might lead to selection of transmission projects in the regional transmission plan for purposes of cost allocation. Among these regions, however, the comprehensiveness of reporting varies with respect to sub-regional transmission planning undertaken by individual transmission owners.

In contrast, the non-ISO/RTO regions report only on transmission projects that are within the scope of their regional coordination activities. These generally do not include all transmission projects planned within the region. Moreover, some regions include critical energy infrastructure information in their studies and therefore do not make their reports publicly available.³⁸

In addition to regional data and reporting, states and utilities provide varying amounts of publicly available information on planned transmission and transmission planning activities. However, reporting

³⁸ Parties can request this information through non-disclosure agreements.

is idiosyncratic and reflective of local practices. Developing consistent information on a regional, much less national, basis may be difficult.

4.2 Transmission Project Costs and Impacts

Information on transmission project costs is even less consistently and less uniformly reported by the regions than other types of information. Project-specific cost information is important for assessing transmission outcomes because it enables comparison of projected and actual as-built costs, which in turn enables improvement in the accuracy of future projections.³⁹

Cost comparisons are important for regions that rely in part on avoided costs for determining benefits because, as described in Section 3, the projected cost of projects that might be avoided will be used to evaluate the efficiency or cost-effectiveness of alternative, sponsored transmission projects that might be selected in the regional transmission plan for purposes of cost allocation. If these alternatives are not selected because they are determined to not be more efficient or cost-effective, it will be important to confirm that the actual costs of the projects they sought to displace were accurate.

It is also important to measure and assess the impacts of transmission projects once they have been built. That is, whether driven by reliability requirements, public policy requirements, or economic considerations (or a combination), the effectiveness of transmission projects in addressing these needs is a principal measure of their performance. The goal should be to assess the performance of transmission projects, especially as it relates to the justifications for approving the project, such as its efficiency or cost-effectiveness compared to alternatives. As with projected costs, truing up past projections is important for informing future projections, especially for transmission projects selected in a regional transmission plan for purposes of cost allocation. We should recognize, too, that retrospective evaluation may prompt review and discussion of the original allocation of project costs. This is inevitable. Hence, it should be anticipated and discussed before evaluations are conducted.

A supporting reason for assessing outcomes, as observed in Eto 2016, is that some have suggested that current methods do not take into account important transmission impacts when assessing cost-effectiveness.⁴⁰ These observers suggest that, as a result, current methods under-value transmission. There is no substitute for reviewing transmission projects once they have been built to determine the projects' material impacts. SPP (2016d) offers a notable example of such an evaluation (see also Budhraj, et al. 2003.)

Comparisons of actual to projected performance are always complicated. Assumptions used to justify transmission projects will change, sometimes dramatically, between the time that projects are planned and the time that they are built. This, too, is inevitable, so it should be expected and addressed

³⁹ Of course, appropriate protections are required for treating proprietary and business-sensitive information related to costs, for example, when a competitive bidding process to select a developer is in progress.

⁴⁰ See, for example, Budhraj, V., et al. (2009), Pfeifenberger, J. and D. Hou. (2012), and Chang, J., J Pfeifenberger, and J Hagerty. (2013).

thoughtfully. Care must be exercised in taking these factors into account and judgment will be required. Moreover, the level of effort appropriate to expend in conducting retrospective evaluations must be balanced by the value of the information provided by the evaluation in informing future planning decisions. Not every project will warrant retrospective review. Yet, it is likely that some will. To conclude that retrospective review is never warranted is tantamount to concluding that there is no value in seeking to learn from past experiences.

4.3 Transmission Planning Processes

This discussion has, so far, focused on assessing aspects of the transmission projects that result from transmission planning processes. In the remainder of this section, we discuss evaluation activities that focus on the conduct and performance of the regional transmission planning practices/processes, which is equally important but far more difficult.

Assessing the manner and means by which regional transmission planning is conducted is important because the regional transmission plans that emerge from regional transmission processes can be understood to reflect regional agreement on what transmission should be built and how its costs should be allocated (whether or not they are allocated regionally). The due process requirements in FERC's orders regarding openness, transparency, open competition, alignment of costs with benefits, etc., are all intended to ensure that these regional decisions will be fair.

Underlying these requirements is the perspective that the question of whether enough transmission is being built is not answered by measuring transmission construction but by confirming the integrity of regional transmission planning processes, including supporting state or local planning activities. That is, the question is answered by understanding whether these processes, taken together, fairly balance the collective interests of a region's stakeholders, starting with those of the consumers who will in the end pay for the consequences of the decisions made through these processes. If the transmission planning processes' meet this standard, then the transmission outcomes of these processes are, by definition, adequate and appropriate. From this point of view, the strength or robustness of the processes confirms their validity as expressions of regional agreement.

The challenge is that, although many aspects of these transmission planning processes can be and are recorded, consensus on what they represent and whether they are meaningful vary. For example, assessing participation in open competitive bidding processes to select transmission projects in the regional transmission plan for purposes of cost allocation will be informative about how incumbent and non-incumbent developers perceive the opportunities to compete. However, as discussed in this report, it will not be informative about other means by which regional transmission needs may be addressed, including by projects not considered for selection in a regional transmission plan for purposes of cost allocation or by non-transmission alternatives. We must pay attention to all means by which regional transmission needs may be met in evaluating the effectiveness of regional planning processes.

As noted in Eto 2016, a means of assessing the fairness or legitimacy of regional transmission planning processes is through stakeholder complaints filed with those managing regional transmission planning processes or with FERC, or reflected in litigation over planning outcomes. For state or local planning processes, there will be similar opportunities for relief that can be tracked. In this sense, the most egregious practices, at least as perceived by those filing complaints or motions, will be adjudicated. Still, inquiry into the fairness of regional (or local) transmission planning processes using these measures will not be comprehensive because the extent to which complaints are filed will depend to a degree on the resources and sophistication of the parties who have concerns about the process outcomes. And, of course, there will always be differences of opinion as to whether the pecuniary interests of parties pursuing these forms of relief appropriately or adequately represent larger interests of the region.

4.4 Emerging Federal Transmission Reporting Activities

We close by highlighting two emerging data-collection and reporting activities, both being led by FERC that bear directly on the discussion in this section. These two activities depend on the data sources reviewed in this section and are therefore also constrained by data limitations, which have already been discussed. Still, these efforts are laudable because they are national in scope and are focused in different ways on the question of whether sufficient transmission is being built.

In March 2016, FERC published a study of transmission metrics.⁴¹ FERC staff developed six metrics that address different aspects of regional transmission planning. The first metric, percentage of non-incumbent transmission project bids or proposals, reviews participation in the open competitive processes created by FERC Order No. 1000 for selecting transmission projects in a regional transmission plan for purposes of cost allocation. The second and third metrics, load-weighted curtailment frequency and RTO/ISO price differential, examine potential drivers for new transmission emerging from economic considerations. The final three metrics, load-weighted transmission investment, load-weighted circuit-miles, and circuit-miles per million dollars of investment, focus on methods for measuring and comparing aspects of new transmission construction.

In August 2016 (revised in October 2016), FERC published a separate report on common metrics.⁴² The report extended older reporting on metrics by ISO/RTOs and expanded this reporting to include a small number of non-ISO/RTOs. With respect to transmission planning, the number of projects approved for reliability purposes from 2010 through 2014 was reported as well as the percentage of approved transmission projects completed from 2010 through 2014.

Both reports are important starts that should be regularly reviewed, revised, and expanded, as appropriate, to establish a consistent national record documenting the progress of transmission planning by the regions.

⁴¹ See <https://www.ferc.gov/legal/staff-reports/2016/03-17-16-report.pdf>

⁴² See <https://www.ferc.gov/legal/staff-reports/2016/08-09-common-metrics.pdf>

4.5 Summary

This section has described regional (and local) transmission planning outcomes and practices that should be reviewed and evaluated over time. The goal of these reviews should be to assess whether and how regional transmission needs are being met. We emphasize the importance of a holistic and, to some degree, region-specific approach to these assessments. This includes considering transmission projects selected for regional cost allocation as well as other means that regions, as a whole (not just regional transmission planning entities) pursue to ensure regional transmission needs are met more efficiently or cost-effectively. We describe a broad range of planning outcomes and activities that should be reviewed to support these assessments, including information on the characteristics of the transmission that is planned and built as well as information on the actual, realized impacts of built transmission in terms of reliability, economics, and public policy requirements. Review activities should also gather information on how regional transmission planning processes are conducted, and the extent to which these planning processes are (or are not) providing meaningful benefits to stakeholders and consumers. Finally, we identify limitations in the public information currently available to support the recommended assessments. Remedying these limitations would provide a stronger basis for evaluating the effectiveness of regional transmission planning activities.

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