FERC Order 1000: Public Utility Compliance and Impacts on States

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About the Author

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Executive Summary

The Order 1000 Rulings represent a fundamental shift in the manner in which regional electric systems will be planned, and their costs allocated, going forward. This paper *summarizes* the Order 1000 Rulings, *recaps* some of the legal concerns underlying the Order 1000 Rulings, and *surveys* nine transmission-provider tariff-compliance filings. The paper ultimately *identifies* three compliance provisions that state regulatory commissioners and staff may consider scrutinizing particularly closely due to their reliability, ratepayer cost and public policy-effectuating consequences.

The paper summarizes five distinct compliance categories required by the Order 1000 Rulings. They are: (1) participation in a regional planning process; (2) consideration of transmission needs driven by public policy requirements, (3) removal of federal right of first refusal from Commission-approved tariffs, (4) regional cost allocation and adherence to six cost-allocation principles, and 5) A requirement on non-public-utility transmission providers who seek to retain their safe harbor tariff to demonstrate compliance with the Order 1000 Rulings. The interregional planning and cost-allocation requirements are not discussed in this paper as compliance with those provisions are due to be filed in April 2013.

The paper next recaps legal arguments stakeholders raised in opposition to the Order 1000 Rulings and FERC responses to those arguments. The recap notes some of the case law that FERC relied upon in supporting its actions and highlights arguments related to Sections 206, 202(a) and 217(b)(4) of the Federal Power Act that both support and oppose FERC's actions in the Order 1000 Rulings.

Third, the paper surveys the initial compliance filings of nine transmission providers, charting the proposed tariff compliance provisions as they relate to Order 890 compliance, consideration of public policy requirements, compliance with cost-allocation principles, non-incumbent participation, and certain miscellaneous provisions. While not comprehensive within these categories, the survey attempts to focus on provisions that state regulators and staff may consider of greatest interest. The nine compliance filings include: (1) PJM Interconnection, (2) Midwest ISO, (3) Southwest Power Pool, (4) ISO New England, (5) New York ISO, (6) California ISO, (7) Northern Tier Transmission Group, (8) WestConnect (through Colorado Public Service Company's filing) and (9) Florida Power and Light. The survey is not informed by Protests or Answers filed after the initial compliance filings.

Finally, the paper identifies three compliance provisions that may require closer state regulatory commission scrutiny due to their reliability, ratepayer cost, and public policy-effectuating consequences. First, the requirement to identify and evaluate transmission needs driven by public policy requirements invites states to have a broad array of public policy requirements considered in regional transmission planning processes, but it also presents state regulators with a host of resource-choice, ratepayer-cost, and reliability-based decisions. Second, the requirement to comply with cost-allocation principle 1 (requiring definition of benefits and beneficiaries) will be further complicated by the public policy analysis and will require states to adopt, to the extent possible, consistent benefit valuation metrics in order to conduct proper regional analyses. Third, Commission determinations of whether transmission provider agreements receive *Mobile-Sierra* protection will necessitate subsequent state regulator assessments. As the Order 1000 Rulings do not affect states' authority regarding transmission construction, states may decide to codify state right-of-first-refusal requirements or, in the alternative, to prohibit state right-of-first-refusal requirements based upon a careful analysis of state-based costs and benefits.

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I. Introduction

On July 21, 2011, the Federal Energy Regulatory Commission ("FERC" or "the Commission"), acting under §206(e) of the Federal Power Act, 16 USC 824[1], issued Order 1000, which mandated that public utility transmission providers ("TPs") under FERC's jurisdiction comply with new planning and cost-allocation reforms. The new reforms were intended to ensure that services provided under FERC's jurisdiction (i.e., transmission services) were provided at just and reasonable rates and on a basis that is just and reasonable and not unduly discriminatory or preferential.[2]

Order 1000 built upon FERC's Order 890 rulings,[3] which imposed nine planning reforms upon local FERC-jurisdictional TP planning processes.[4] Since the Order 890 rulings, FERC concluded that additional reforms were necessary to ensure, "in light of changing conditions in the industry,"[5] that FERC-jurisdictional rates for transmission services remain just and reasonable and not unduly discriminatory or preferential.

Orders 1000, 1000-A and 1000-B (collectively, the "Order 1000 Rulings" or "the Orders") enacted reforms in three broad categories: regional and interregional planning, the rights of third-party transmission providers, and regional and interregional cost allocation.[6] The

[1] "Whenever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any public utility for any transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affected such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order. 16 U.S.C. 824(e) (2006)."

[2] *See* FERC Order 1000, 136 FERC ¶61,051, July 21, 2011.

[3] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, (Mar. 15, 2007), Order on Reh'g, Order No. 890-A, (Jan. 16, 2008); Order on Reh'g and Clarification, Order No. 890-B, (July 8, 2008); Order on Reh'g, Order No. 890-C, (Mar. 25, 2009); and Order on Clarification, Order No. 890-D, (Nov. 25, 2009).

[4] Order 890 Planning Reforms include: (1) Coordination; (2)Openness; (3) Transparency; (4) Information Exchange; (5) Comparability; (6) Dispute Resolution; (7) Regional Participation; (8) Economic Planning Studies; and (9) Cost Allocation for New Projects. *See* id.

[5] FERC Order 1000, ¶ 1. FERC discusses these changing conditions throughout its Orders, and while they are not the focus on this paper, they include, among others, near- and long-term projected changes to the generation fleet driven largely by federal environmental regulations, state renewable portfolio standards and existing plant retirements. The shifting generation fleet will require billions of dollars of investment in new transmission facilities to ensure that transmission services are provided reliably, cost-effectively and in a manner that meets public policy objectives. *See* FERC Order 1000, ¶¶'s 44-46.

[6] FERC developed a record upon which to base its Order 1000 reforms by holding regional technical conferences in September 2009, issuing a Notice of Requests for Comments in October 2009 (Docket No, AD09-8-000), issuing a Notice of Proposed Rulemaking in June 2010 (RM10-23-000), and compiling and responding to the stakeholder comments in each of the aforementioned proceedings.

Orders provided TPs 12 months to submit compliance filings on the regional-planning, rights-of-third-parties, and regional cost-allocation requirements and 18 months to submit compliance filings on the interregional-planning and cost-allocation requirements.[7] The first set of compliance filings was due from most utilities in October 2012 and the second set in April 2013.[8]

This paper will discuss the Order 1000 Rulings and compliance filings made by FERC-jurisdictional TPs on the issues of regional planning reforms, reforms concerning the rights of third-party transmission providers, and regional cost-allocation reforms—those topics required for inclusion in the October 2012 compliance filings—with an eye toward informing state public utility regulatory commissions of the potential impacts of compliance.[9] In particular, the paper will examine the tariff provisions particular TPs have filed in order to comply with the Order 1000 Rulings and compile the diversity of methods proposed to achieve compliance. It will attempt to identify provisions among the various compliance approaches that may most significantly impact state electric regulatory commissions (e.g., those provisions that may cause cost, policy or jurisdictional impacts).

Section II of this paper will summarize the reforms outlined in Order 1000 and clarified in Orders 1000-A and 1000-B. Section III will briefly recap challenges to FERC's authority to implement the Order 1000 Rulings and FERC's responses. A brief discussion of challenges and responses may provide helpful context to certain TP tariff revisions. Section IV will examine tariff provisions included in the compliance filings of particular TPs with respect to regional planning, third-party TP rights and regional cost allocation. Finally, Section V will identify and discuss certain rule and compliance provisions that may most impact state electric regulatory commissions.

[7] FERC Order 1000, ¶792.

[8] A number of TPs requested and received extensions of the filing deadline. They included PJM Interconnection, Midwest Independent System Operator, Southwest Power Pool, New England Independent System Operator, Southern Company and others.

[9] In recognition that compliance with FERC Orders in oftentimes a lengthy and on-going process, this research paper is limited in that it examines only a sample of initial compliance filings, and is not informed by stakeholder protests, TP responses to protests or subsequent FERC rulings. Such matters may be addressed in a later paper.

II. Requirements of the Order 1000 Rulings

The Order 1000 Rulings[10] discuss new tariff requirements on all FERC-jurisdictional TPs in the areas of planning, the rights of third-party transmission providers, and cost allocation, as well as requirements and participation options for non-public-utility TPs.

It is important to keep in mind that Order 1000 focuses on the transmission planning ***process*** and not on substantive outcomes. FERC believes that the reforms work together to remedy deficiencies in the existing requirements of Order 890 and will enable the Commission to ensure that services are provided at rates, terms, and conditions of service that are just and reasonable and not unduly discriminatory or preferential.[11] The Commission referred to the Order 1000 Rulings as a package of reforms that will help ensure that each TP works within its transmission planning region to create a regional transmission plan that *identifies* transmission facilities needed to meet reliability, economic, and public policy requirements ("PPRs"); *includes* fair consideration of lines proposed by non-incumbents; and *contains* cost-allocation mechanisms to facilitate lines moving from planning to development.[12]

There are many ways in which to divide up and discuss the requirements of the Order 1000 rulings. This section divides the requirements into seven distinct requirements and discusses the five requirements relevant to this paper:

A. A requirement to participate in a regional transmission planning process that evaluates transmission alternatives at the regional level that may resolve the transmission planning region's needs more efficiently and cost-effectively than alternatives identified by individual public utility transmission providers in their local transmission planning processes, and that results in the development of a regional transmission plan.[13]

B. A requirement to provide an opportunity to consider transmission-needs-driven PPRs.[14]

C. A requirement to remove from their Open Access Transmission Tariffs ("OATTs") or other Commission-jurisdictional tariffs and agreements any provisions that grant a federal right of first refusal ("ROFR") to transmission

[10] Order 1000-A addressed Requests for Rehearing of Order 1000 and was issued May 17, 2012, and Order 1000-B addressed Requests for Rehearing of Order 1000-A and was issued on October 18, 2012.

[11] *See* Order 1000, ¶12.

[12] *See* Order 1000, ¶47. The Commission also refers to the package of reforms as ***a minimum set of requirements*** which must be met in order to ensure FPA compliance. *See* id., ¶ 55. (Emphasis added).

[13] *See* id., ¶6.

[14] Id.

facilities that are selected in a regional transmission plan for purposes of cost allocation.[15]

D. A requirement to improve coordination across regional transmission planning processes by developing and implementing, through their respective regional transmission planning process, procedures for joint evaluation and sharing of information regarding the respective transmission needs of transmission planning regions and potential solutions to those needs.[16]

E. A requirement to have in place a method, or set of methods, for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation.[17]

The cost-allocation requirements, which apply to regional and interregional cost-allocation methods, include adherence to six regional and interregional cost-allocation principles, discussed herein.[18]

F. A requirement to have, together with the TPs in a neighboring transmission planning region, a common method, or set of methods, for allocating the costs of a new interregional transmission facility that is jointly evaluated by the two or more transmission planning regions in their interregional transmission coordination procedures.[19]

G. A requirement upon non-public-utility TPs seeking to maintain a safe harbor tariff to ensure that the provisions of that tariff substantially conform, or are superior to, the pro forma OATT as it has been revised by this Final Rule.[20]

Except for requirements D (Interregional Coordination) and F (Interregional Cost Allocation), which TP compliance tariffs will address in April 2013, this section turns to each of the other requirements in more detail. It should be noted at the outset, that FERC allowed, *to the extent that existing transmission planning processes satisfy the requirements of the Order 1000 Rulings*, that TPs need not revise their OATTs and, instead, should describe in their compliance filings how the relevant requirements are satisfied by reference to tariff sheets already on file with the Commission.[21]

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[15] Id., ¶7.

[16] Id., ¶8.

[17] Id., ¶9.

[18] *See* id.

[19] Id.

[20] Id., ¶663. However, it remains up to each non-public-utility TP whether it wants to maintain its safe harbor status by meeting the transmission planning and cost allocation requirements of this Final Rule.

[21] *See* id., fn. 71 (Emphasis added).

A. Participation in a regional planning process that identifies alternatives and produces a regional plan

1. Evaluation of alternatives

In requiring TPs to participate in a regional transmission planning process, FERC concluded that it is necessary to have *an affirmative obligation* in transmission planning regions to evaluate alternatives that may meet the needs of the region more efficiently or cost-effectively.[22] FERC believes the affirmative obligation is necessary because proactive cooperation among TPs within a transmission planning region could better identify transmission solutions to more efficiently or cost-effectively meet the reliability needs of TPs in the region.[23]

Providing examples of the types of analysis regional planning processes may entertain, FERC stated "there are many ways potential upgrades to the transmission system can be studied…ranging from the use of scenario analyses to production cost or power flow simulations."[24] This provision is indicative of the types of flexibility FERC offers each region in the Order 1000 Rulings, requiring the development of a regional plan but declining to mandate particular types of analyses.

Providing further guidance on evaluation requirements, the Commission stated that tariff language could, for example, state that solutions will be evaluated against each other based on a comparison of their relative economics and effectiveness of performance. Although the particular standard a TP uses to perform this evaluation can vary, the Commission explained that it should be clear from the tariff language how one type of investment would be considered against another and how the TP would choose one resource over another or a competing proposal.[25]

Regarding the evaluation of the merits of alternative solutions, FERC stated that TPs also must consider proposed non-transmission alternatives ("NTAs") on a comparable basis.[26] In requiring comparable consideration of transmission alternatives and NTAs, FERC stated TPs are required to identify how they will evaluate and select from competing solutions and resources such that all types of resources are considered on a comparable basis.[27]

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[22] *See* id., ¶80. FERC included in Order 1000 a requirement upon TPs to amend their OATTs to describe the circumstances and procedures under which TPs will ***reevaluate*** the regional transmission plan to determine if delays in the development of a transmission facility selected in a regional transmission plan for purposes of cost allocation require evaluation of alternative solutions to ensure the incumbent can meet its reliability needs or service obligations. *See* id., ¶¶s 7, 263 (emphasis added).

[23] *See* id., ¶81.

[24] Id. ¶149.

[25] *See* id., fn. 149.

[26] *See* Order 1000, ¶148.

[27] *See* id., ¶155.

2. Application of Order 890 planning principles

It is important to note that FERC requires each TP to apply the Order 890 Planning Principles (see fn. 4, *supra.*) to their respective regional planning processes and for TPs to reflect this in their compliance tariffs.[28] As an example, affirming the importance of stakeholder participation (Principle 7), FERC stated that ensuring access to the models and data used in the regional transmission planning process will allow stakeholders to determine if their needs are being addressed in a more efficient or cost-effective manner.[29] Providing further clarification, FERC noted that TPs should provide the basic methodology, criteria, and processes used to develop transmission plans *sufficient for stakeholders to be able to replicate its transmission plans*, and describe the methods it will use to disclose the criteria, data, and assumptions that underlie its transmission system plans.[30]

3. Data-sharing requirements for merchants

FERC also addressed the interaction of non-public-utility or merchant TPs with regional planning processes. Declining to require their participation in planning processes because merchant developers assume all financial risks for developing and constructing its projects, Order 1000 required the merchant to provide adequate information and data to allow TPs in the transmission planning region to assess the potential reliability and operational impacts of a proposed merchant line on the region.[31]

4. Planning region defined

Finally, providing clarification on the constitution of a planning region, FERC stated that a transmission planning region is one in which TPs, in consultation with stakeholders and affected states, have joined for purposes of satisfying the requirements of Order No. 1000, including among other purposes, to develop a regional transmission plan.[32]

B. Consideration of transmission needs driven by public policy requirements

Order 1000 stated that, when conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving

[28] *See* Id., ¶161. The regional participation and cost-allocation principles are subjects of specific reform in Order 1000. (*See* Order 1000-A, fn. 294).

[29] *See* id., ¶150.

[30] *See* Order 1000-A, ¶281 (emphasis added).

[31] *See* id., ¶164. FERC states that Order No. 1000's information sharing requirement balances the need for TPs and stakeholders in transmission planning regions to know about the impacts of potential merchant transmission facilities in their regions without requiring a specific degree of participation by merchant transmission developers in the regional transmission planning process when they are not establishing a cost-based rate base to be allocated to other beneficiaries of that facility. *See* Order 1000-A, ¶298.

[32] *See* Order 1000-A, ¶233.

native load, "but also consider how to plan for transmission needs driven by Public Policy Requirements."[33]

Confirming that the requirement is process-oriented rather than results-oriented, the Commission asserted that it is simply requiring the consideration of facts that are relevant to the transmission planning process, and in doing so, it is ***neither pursuing nor enforcing any specific policy goals***.[34] FERC clarified its position further in Order 1000-A affirming that it is not placing TPs in the position of being policymakers or allowing them to substitute their public policy judgments in the place of legislators and regulators; rather, transmission needs driven by PPRs, and not the PPRs themselves, are what must be considered under Order No. 1000.[35]

Order 1000 requires each public utility TP to coordinate with its stakeholders to identify PPRs that are appropriate to include in its local and regional transmission planning processes.[36] FERC believes that these reforms will remedy opportunities for undue discrimination by requiring TPs to have in place processes that provide all stakeholders the opportunity to provide input into what they believe are transmission needs driven by PPRs, rather than the TP planning only for its own needs or the needs of its native load customers.[37]

FERC clarified that PPRs established by state or federal laws or regulations includes duly enacted laws or regulations passed by a local governmental entity, such as a municipal or county government.[38] FERC also required TPs to post on their websites an explanation of which transmission needs driven by PPRs will be evaluated for potential solutions in the local or regional transmission planning process, as well as an explanation of why other suggested transmission needs will not be evaluated.[39]

Finally, regarding the adoption of flexible planning parameters or a bright-line test, FERC did not require those with existing bright line criteria to adopt flexible criteria if they do

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[33] *See* Order 1000, ¶83

[34] *See* id., ¶111. The obligation does not establish an independent requirement to satisfy the PPRs. *See* id., ¶ 213.

[35] *See* Order 1000-A, ¶318.

[36] *See* Order 1000, ¶167. FERC leaves it to the TPs, in consultation with their stakeholders, to design the appropriate procedures for identifying and evaluating the transmission needs that are driven by PPRs in their area, subject to FERC's review on compliance. Id., ¶ 209.

[37] *See* id., ¶203. FERC clarified that by considering transmission needs driven by PPRs, it meant: (1) the identification of transmission needs driven by PPRs; and (2) the evaluation of potential solutions to meet those needs. *See* id., ¶ 205.

[38] *See* Order 1000-A, ¶319.

[39] *See* Order 1000, ¶209. Further clarifying the posting requirement, FERC stated that TPs are only obligated to (a) post an explanation of those transmission needs driven by PPRs that have been identified for evaluation and (b) post an explanation of how other transmission needs driven by PPRs introduced by stakeholders were considered during the identification stage and why they were not selected for further evaluation. *See* Order 1000-A, ¶325.

not wish to do so.[40] Instead, FERC decided to evaluate both bright-line and flexible criteria on compliance for whether they permit unjust and unreasonable rates or undue discrimination, and whether they will ensure fair consideration of transmission needs driven by PPRs as well as reliability needs and economic considerations.[41]

C. Removal of federal rights of first refusal from commission-approved tariffs and agreements

FERC stated that failure to remove the ROFR from FERC tariffs would leave in place practices that have the potential to undermine the identification and evaluation of ***more efficient or cost-effective solutions to regional transmission needs***, which in turn can result in rates for Commission-jurisdictional services that are unjust and unreasonable or otherwise result in undue discrimination by TPs.[42]

1. Criteria, protocols, and frameworks

On compliance, TPs must develop qualification criteria and protocols to govern the submission and evaluation of proposals for transmission facilities to be evaluated in the transmission planning process.[43] This includes a clear enrollment process that defines how entities, including non-public-utility TPs, make the choice to become part of the transmission planning region. In addition, each TP[44] must include in its OATT a list of all the public utility and non-public-utility TPs that have enrolled as transmission providers in its transmission planning region.[45]

To enable greater competition among incumbent and merchant TPs in regional planning processes, FERC required jurisdictional TPs to include in their compliance tariffs ***a framework*** including:[46]

1. Qualification criteria to submit a transmission project for selection in the regional transmission plan for purposes of cost allocation;[47]

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[40] *See* id., ¶224.

[41] *See* id. FERC did acknowledge the merit in using a flexible approach stating it may capture certain transmission projects that might be unnecessarily excluded with a bright-line approach. *See* Order 1000-A, ¶284.

[42] *See* id., ¶ 253.

[43] *See* Order 1000, ¶225.

[44] TP can refer to a regional transmission planning entity acting for all of the public utility transmission providers in its transmission planning region, such as an RTO or ISO.

[45] *See* Order 1000-A, ¶275.

[46] This framework was first proposed in Order 1000, ¶431 but modified on rehearing in Order 1000-A, ¶293.

[47] *See* Order 1000-A, ¶441. FERC cautioned that it would be an impermissible barrier to entry to require, as part of the qualification criteria, that a transmission developer demonstrate that it either

2. Specification of the date by which such information must be submitted to be considered in a given transmission planning cycle;

3. Description of a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation as well as a reevaluation process;[48] and

4. Removal, along with corresponding changes in any other Commission-jurisdictional agreements, of provisions that establish a federal ROFR for an incumbent transmission provider[49] and provide a comparable opportunity for incumbent and non-incumbent transmission project developers to recover the cost of a selected transmission facility through a regional cost-allocation method.

2. Comparability

FERC further required that any non-incumbent developer of a transmission facility *selected in the regional transmission plan* have an opportunity comparable to that of an incumbent transmission developer to allocate the cost of such transmission facility through a regional cost-allocation method or methods.[50]

Importantly, the Commission declined to require TPs to revise their OATTs to provide a transmission developer with the right to construct and own a transmission facility and also declined to allow a transmission developer to maintain for a defined period of time its right to build and own a transmission project that it proposed but that is not selected.[51]

However, if a transmission facility is selected in the regional transmission plan for purposes of cost allocation, the Commission clarified that the transmission developer of that transmission facility must submit a development schedule that indicates the required steps, such as the granting of state approvals, necessary to develop and construct the transmission facility such that it meets the transmission needs of the region.[52] As part of the ongoing monitoring of

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has or can obtain state approvals necessary to operate in a state, including state public utility status and the right to eminent domain, to be eligible to propose a transmission facility.

[48] *See* fn. 22, *supra*.

[49] Eligibility for regional cost allocation is tied to the transmission facility's selection in the regional transmission plan for purposes of cost allocation and not to a specific sponsor. *See* Order 1000-A, ¶335.

[50] *See* Order 1000, ¶225 (emphasis added). FERC further stated incumbents and non-incumbents should share similar benefits and obligations commensurate with that participation, including the right, consistent with state or local laws or regulations, to construct and own a transmission facility that it sponsors in a regional transmission planning process and that is selected in the regional transmission plan. *See* id., ¶ 294.

[51] *See* id.

[52] *See* id., ¶442.

the progress of the transmission project once it is selected, TPs in a transmission planning region must establish a date by which state approvals to construct must be achieved that is tied to when construction must begin to timely meet the need that the project is selected to address.[53] If such critical steps have not been achieved by that date, then the TPs may remove the transmission project from the selected category and proceed with reevaluating the regional transmission plan to seek an alternative solution.[54]

3. Maintenance of the ROFR

FERC offered circumstances in which federal ROFRs may be maintained. For example, the Commission did not require ROFR removal from tariffs and agreements applicable to local transmission facilities;[55] when performing upgrades to its own transmission facilities such as tower change-outs or re-conductoring; to alter a TP's existing control of its rights-of-way;[56] or if the regional cost-allocation method results in 100% of the facility's cost being allocated to the TP in whose retail distribution service territory or footprint the facility is to be located.[57]

On rehearing and in response to concerns that removal of ROFRs may run afoul of the well-established *Mobile-Sierra* doctrine, FERC also clarified that compliance filings must include the revisions to any Commission-jurisdictional tariffs and agreements necessary to comply with Order No. 1000 as well as the TP's *Mobile-Sierra* arguments.[58] The Commission clarified that it is not requiring TPs to eliminate a federal ROFR before it makes a determination regarding whether an agreement is protected by the *Mobile-Sierra* doctrine and whether the Commission has met the applicable standard of review.[59]

Finally, FERC clarified that if a violation of a NERC reliability standard would result from a non-incumbent transmission developer's decision to abandon a transmission facility meant to address such a violation, the incumbent TP does not have the obligation to construct the

[53] Id.

[54] Id.

[55] *See* Order 1000, ¶318.

[56] *See* id., ¶319.

[57] *See* Order 100-A, ¶423. The Commission clarified that the term "selected in a regional transmission plan for purposes of cost allocation" excludes a new transmission facility if the costs of that facility are borne entirely by the TP in whose retail distribution service territory or footprint that new transmission facility is to be located. *See* Order 1000-B, ¶41.

[58] *See* id., ¶ 389. Specifically, the Commission stated that it must first determine "whether the agreement is protected by a *Mobile-Sierra* provision, and if so, whether the Commission has met the applicable standard of review such that it can require the modification of the particular provisions. If the Commission determines that the agreement is protected by a *Mobile- Sierra* provision and that it cannot meet the applicable standard of review, then the Commission will not consider whether the revisions submitted to the Commission jurisdictional tariffs and agreements comply with Order No. 1000." Id. Please see Appendix C to this paper for a discussion of the *Mobile-Sierra* Doctrine and the Public Interest Standard.

[59] *See* Order 1000-B, ¶40.

non-incumbent's project, but rather, the incumbent must identify the specific NERC reliability standard(s) that will be violated and submit a NERC mitigation plan to address the violation.[60]

D. Interregional coordination, including joint evaluation and information sharing

Order 1000's interregional coordination provision contains four requirements:

1. Development and implementation of procedures that provide for the sharing of information regarding the respective needs of neighboring transmission planning regions, as well as the identification and joint evaluation by the neighboring transmission planning regions of potential interregional transmission facilities that address those needs;

2. Development and implementation of procedures for neighboring public utility transmission providers to identify and jointly evaluate transmission facilities that are proposed to be located in both regions;

3. Exchange of planning data and information between neighboring transmission planning regions at least annually; and

4. Maintenance of a website or e-mail list for the communication of information related to interregional transmission coordination.[61]

E. Adoption of cost-allocation method(s) for new projects selected in regional transmission plans for purposes of cost allocation

Order No. 1000's cost-allocation reforms are grounded in FERC's determination that it is necessary to establish ***a closer link between regional transmission planning and cost allocation***, both of which involve the identification of beneficiaries of new transmission facilities.[62]

At the outset, it is important to note that Order 1000 distinguishes between a *transmission facility in a regional transmission plan* and a *transmission facility* ***selected*** *in a regional transmission plan* ***for purposes of cost allocation***. The latter term includes facilities that have been selected pursuant to a transmission planning region's Commission-approved regional transmission planning process for inclusion in a regional transmission plan for purposes of cost

[60] *See* Order 1000, ¶344.

[61] *See* id., ¶ 345. As interregional coordination compliance tariffs are not due until April 2013, they were not included in TP compliance filings relevant to this paper and will not be discusses here.

[62] *See* id. ¶556 (emphasis added). In Order 890, the Commission explained that knowing how the costs of transmission facilities would be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs. *See* id., ¶496.

allocation because they are more efficient or cost-effective solutions to regional transmission needs.[63]

1. Free-ridership

The rules also seek to prevent the free-ridership opportunities created by transmission service as the nature of power flows over an interconnected transmission system does not permit a TP to withhold service from those who benefit from those services but have not agreed to pay for them.[64] FERC notes that it is possible that an entity that uses part of the transmission grid will obtain benefits from transmission facility enlargements and improvements in another part of that grid regardless of whether they have a contract for service on that part of the grid and regardless of whether they pay for those benefits. According to FERC, this is the essence of the "free rider" problem the Commission is seeking to address through its cost-allocation reforms.[65]

2. Comparability

FERC required that the OATTS of all TPs in a region must include ***the same cost-allocation method*** or methods adopted by the region; and they must adhere to six cost-allocation principles (discussed below).[66] While each transmission planning region may develop a method or methods for different types of transmission projects, such method or methods should apply to all transmission facilities of the type in question.[67] If TPs choose to propose a different cost-allocation method or methods for different types of transmission facilities, each method would have to be determined in advance for each type of facility.[68]

3. Treatment of participant funding

FERC declared that participant funding is inadequate as a region's sole cost-allocation methodology. Its reasons include a growing need for transmission facilities that cross jurisdictions and a diffusion of benefits associated with transmission facilities.[69] However, transmission developers who see particular advantages in participant funding remain free to use

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[63] *See* id., ¶63 (emphasis added).

[64] *See* id., ¶534.

[65] *See* Order 1000-A, ¶562. FERC adds that rather than contractual relationships, the benefits received by users of the regional transmission grid provide a basis for how costs should be allocated. *See* id., ¶ 565.

[66] *See* id., ¶482 (emphasis added).

[67] Id., ¶560.

[68] Id. This is so that developers have greater certainty about cost allocation and other stakeholders will understand the cost impacts of the transmission facilities proposed for cost allocation in transmission planning. Id., ¶ 562.

[69] *See* id., ¶497.

it on their own or jointly with others, but then simply cannot pursuing regional or interregional cost allocation.[70]

TPs must document the steps they have taken to reach consensus on a cost-allocation method or set of methods to comply with this Final Rule, as thoroughly as practicable, and provide whatever information they view as necessary for the Commission to make a determination of the appropriate cost-allocation method or methods.[71] Finally, FERC stated that in the event of a failure to reach an agreement on a cost-allocation method or methods, the Commission will use the record in the relevant compliance filing proceeding as a basis to develop a cost-allocation method or methods that meets Order No. 1000's cost-allocation principles.[72]

The six (6) cost-allocation principles are listed below:

Regional Cost-Allocation Planning Principle 1

> The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of transmission facilities, a regional transmission planning process may consider benefits including, but not limited to the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting PPRs.[73]

The Commission stated that it may determine an entity is a beneficiary of a transmission facility even if it has not entered a voluntary arrangement with the TP that is seeking to recover the costs of that transmission facility.[74] FERC also stated that in order to prevent cross-subsidization of beneficiaries, cost-causation is the foundation of an acceptable cost-allocation method.[75] Finally, FERC left the determination of benefits to be addressed "in the first instance" to the TPs and their stakeholders in the development of the cost-allocation methods for their

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[70] *See* Order 1000-A, ¶ 729. It is also possible that the developer of a facility selected in the regional transmission plan for purposes of cost allocation might decline to pursue regional cost allocation and, instead, rely on participant funding. Id., ¶725.

[71] *See* id., ¶607.

[72] *See* id., ¶650.

[73] *See* Order 1000, ¶622

[74] *See* id., ¶505

[75] *See* id., ¶626.

regions.[76] However, it stated that in order to be compliant, the TP must clearly and definitively specify the benefits and the class of beneficiaries.[77]

Regional Cost-Allocation Planning Principle 2

> Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.[78]

Regarding transmission needs driven by PPRs, FERC stated those that receive no benefit from new transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those facilities.[79]

The Commission clarified on Rehearing that the use of "likely future scenarios" would not expand the class of customers who would be identified as beneficiaries because it is limited to scenarios in which a beneficiary is identified as such on the basis of the cost causation principle.[80] Therefore, in asserting that this principle would be satisfied if a project or group of projects is shown to have benefits in one or more of the transmission planning scenarios identified by TPs in their Commission-approved Order No. 1000-compliant cost-allocation methods, the Commission clarified that it did not intend to remove the "likely future scenarios" concept from transmission planning.[81]

Regional Cost-Allocation Planning Principle 3

> If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation. A public utility transmission provider in a transmission planning region may choose to use such a threshold to account for uncertainty in the calculation of benefits and costs. If adopted, such a threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the transmission planning region or public utility transmission provider justifies and the Commission approves a higher ratio.[82]

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[76] *See* Order 1000-A, ¶676.

[77] *See* id., ¶678.

[78] *See* Order 1000, ¶637.

[79] Id., ¶219.

[80] *See* Order 1000-B, ¶69.

[81] *See* id., ¶72.

[82] Order 1000, ¶646

FERC believes that a transparent benefit-to-cost ratio may help certain transmission planning regions to determine which transmission facilities have sufficient net benefits to be selected in the regional transmission plan for purposes of cost allocation.[83]

Regional Cost-Allocation Planning Principle 4

> The allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs. However, the transmission planning process in the original region must identify consequences for other transmission planning regions, such as upgrades required in another region, and if the original region agrees to bear the costs associated with such upgrades, then the original region's cost allocation method or methods must include provisions for allocating the costs of the upgrades among the beneficiaries in the original region.[84]

Regional Cost-Allocation Planning Principle 5

> The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.[85]

Regional Cost-Allocation Planning Principle 6

> A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements. Each cost allocation method must be set out clearly and explained in detail in the compliance filing for this rule.[86]

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[83] *See* id., ¶648.

[84] Id., ¶657.

[85] Id., ¶668.

[86] Id., ¶685.

F. Adoption of cost-allocation method(s) for new interregional projects evaluated in neighboring regional transmission planning processes

Interregional cost-allocation compliance provisions are due to the Commission in April 2013 and will not be discussed in this paper.

G. Maintenance of safe-harbor tariff that conforms to order 1000

On the issue of the Order 1000 Rulings' reciprocity with non-public-utility TPs, the Commission determined that if it found that non-public-utility TPs were not participating in the transmission planning and transmission cost-allocation procedures required by the final rule, it may, on a case-by-case basis, choose to exercise its authority under FPA section 211A.[87]

The Commission stated that it is within its discretion to allow a TP to refuse to offer open access transmission service to any non-public-utility TP that does not provide comparable reciprocal transmission service insofar as it is capable of doing so, including regional planning and cost allocation.[88] However, as noted above, it is only when a non-public-utility TP actually makes the choice to become part of a transmission planning region by enrolling in that region that it would be subject to the regional and interregional cost-allocation methods for that region.[89]

Also, a TP will not be deemed out of compliance with Order 1000 if it demonstrates that it made a good-faith effort, but was unable to reach resolution with a neighboring non-public-utility TP on a regional or interregional transmission plan or cost-allocation method.[90]

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[87] *See* id., ¶815. FPA section 211A(b) provides, in pertinent part, that "the Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services – (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential." 16 U.S.C. 824j.

[88] *See* Order 1000-A, ¶776.

[89] *See* id.

[90] *See* id., ¶754.

III. Legal Concerns Underlying the Order 1000 Rulings

This section briefly summarizes legal concerns with FERC's authority to issue the Order 1000 Rulings and FERC's responses to those concerns. At the time of the drafting of this paper, while most FERC-jurisdictional TPs had made initial compliance filings, many stakeholders had also filed petitions with the federal courts for review of the Order 1000 Rulings.[91] Because many of the arguments that parties raised throughout the rulemaking docket and in requests for rehearing and clarification are likely to resemble arguments made in the federal courts (if petitions are accepted), a brief summary of concerns and responses follow.

A. Motivations for Order 1000 reform

As noted in Section II, FERC stated that existing and potential environmental regulations and state renewable portfolio standards are driving significant changes in the mix of resources, resulting in the early retirement of coal-fired generation, increased reliance on natural gas for electricity generation and large-scale integration of renewable integration.[92] These shifts in the generation fleet have increased the need for new transmission the existing transmission grids were not built to accommodate those shifts.[93]

In offering justifications for its new planning reforms, FERC listed elements that constitute *effective* transmission planning, such as:

- coordination among transmission planning entities;
- openness and transparency, which is necessary for any process that involves multiple entities with a variety of needs or views regarding this process;
- consideration of all transmission needs of all transmission customers;
- a resulting identifiable product reflecting regional determinations;
- a lack of unnecessary barriers to the consideration of good ideas or the selection of the most advantageous transmission solutions, regardless of whether the developer of a transmission solution is an incumbent transmission developer/provider or a non-incumbent transmission developer;
- recognition that there may be even more efficient or cost-effective solutions that are identified through interregional transmission coordination efforts than those solutions identified in a regional transmission planning process; and finally

[91] Parties petitioning the federal appellate courts for review include: Oklahoma Gas & Electric, the Midwest ISO Transmission Owners, ITC Holdings Co., American Public Power Association, Large Public Power Council, National Rural Electric Cooperative Association, the PSEG Companies, Southern Companies Services, Inc., First Energy Companies, New York ISO, Edison Electric Institute, Coalition for Fair Transmission Policy, South Carolina Public Service Authority, the Sacramento Municipal Utility District, and others. *See* Docket No. RM10-23 Docket Sheet.

[92] *See* Order 1000-A, ¶5 (Referring to the Order 890 Rulings).

[93] *See* id. The Commission cites NERC's 2009 Assessment, which stated that existing and potential environmental regulation and state renewable portfolio standards are driving significant changes in the generation mix, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable generation. *See* id., ¶50.

- performance with a clear *ex ante* understanding of who will pay for a facility selected in a regional transmission plan for purposes of cost allocation.[94]

Rather than wait for systemic problems to undermine transmission planning before action is taken, the Commission concluded that it must act promptly to establish rules and processes necessary to allow TPs to ensure planning of and investment in the right transmission facilities.[95]

The Commission determined that the problem it seeks to resolve (i.e., "the narrow focus of current planning requirements and the shortcomings of current cost allocation practices") represents a significant "theoretical threat" that justifies Order No. 1000's requirements and is not one that the Commission can address adequately or efficiently through the adjudication of individual complaints.[96] FERC also stated that it did not need to make specific factual findings of discrimination in order to promulgate a generic rule to ensure just and reasonable rates or eliminate undue discrimination.[97]

B. Objections to Order 1000 reforms

Stakeholder objections to the Order 1000 Rulings included attacks on Commission authority to promulgate the Order 1000 Rulings under FPA §§'s 206, 202(a) and 217(b)(4), among others.[98] Certain parties expressed concern about Commission overreach beyond its limited FPA authority, while others contended that FERC did not specifically define which terms or conditions had resulted in discriminatory conduct.[99] Other parties cited a lack of evidence that current planning processes produced unreasonable results.[100]

Some parties stated that their regional grids were already deemed to be sufficiently robust or that certain underlying motivations, such as remotely-located renewable resources, were not applicable to their regions.[101] Objections were also made that the burdens and costs imposed by the Order 1000 Rulings were not justified by the theoretical threat, and that the Order 1000 Rulings will lead to inefficiencies and reliability problems by diverting planning engineers from native load to interregional planning stakeholder concerns.[102] Finally, assertions were made that

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[94] *See* id., ¶ 52.

[95] *See* id., ¶6.

[96] *See* id., ¶7.

[97] *See* id., ¶9. In making these assertions, FERC relied on the precedent established by the courts in *National Fuel Gas Supply Corp. v. FERC,* 468 F.3d 831 (D.C. Cir. 2006) and *Associated Gas Distrib. v. FERC*, 824 F.2d 981 (D.C. Cir. 1985) respectively.

[98] This section will not review individual party arguments, as those are included and responded to in Orders 1000-A and 1000-B. Rather, this section highlights certain arguments made against the need for reform.

[99] *See* Order 1000-A., ¶¶'s 13, 14.

[100] *See* id., ¶17.

[101] *See* id., ¶¶'s 25, 27.

[102] *See* id., ¶¶'s 32, 47.

Order 1000 reforms were premature as the interconnection-wide planning processes may eliminate the need for reforms or indicate a need for different reforms.[103]

C. Commission responses to legal challenges to the need for reform

1. General responses

Relying on its interpretations of the precedents set in *National Fuel* and *Associated Gas*, FERC responded that as an "actual problem" occurs when a theoretical threat comes to fruition, to therefore insist that the Commission must identify the existence of an actual problem in the present before it can act is to deny that a theoretical threat that one reasonably concludes exists can be a basis for action.[104]

Responding to concerns that it has overreached its authority to order regional planning, FERC asserted that since Order No. 1000 establishes a set of minimum requirements that regional planning must meet and allows considerable flexibility in the implementation of these requirements, the establishment of flexible minimum requirements for a process cannot be equated with commandeering that process.[105]

Responding to concerns that Order 1000 favors non-incumbent TPs, FERC asserted that Order 1000 simply established minimum requirements for the treatment of non-incumbent transmission developers in the transmission planning process, and that these requirements do not confer any rights to develop a facility, but rather they only confer a right to have a proposal considered.[106]

Finally, responding to concerns that FERC's justifications for the need for reforms were ambiguous, FERC responded that its reference, for example, to such things as the impacts of renewable portfolio policies were not ambiguous as these policies affect transmission needs and thus transmission rates, and rather than being ambiguous, they provide a clear and concrete example of how transmission planning cannot be fully effective if it does not consider all transmission needs.[107]

[103] *See* id., ¶34.

[104] *See* id., ¶65.

[105] *See* id., ¶99.

[106] *See* id., ¶67. FERC notes further that the fact that an incumbent transmission developer/provider may possess certain capabilities does not imply that the incumbent transmission developer/provider is more capable than any possible non-incumbent transmission developer in all situations. *See* id., ¶88.

[107] *See* id., ¶98.

2. Responses to statutory challenges

a. FPA §202(a)

FPA §202(a) states:

> For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy. . . .[108]

Some stakeholders argued that the Commission could not impose planning reforms because §202(a) of the FPA determined that coordination of transmission facilities, which includes their planning, is to be voluntary.

FERC countered that by "interconnection and coordination," the FPA means that the "coordinated operation" of facilities be voluntary and that Section 202(a) is silent on and established no implicit limits on transmission "planning."[109] This is because, according to FERC, the planning of new transmission facilities occurs before they can be interconnected, and for this reason any transmission planning relevant to these facilities occurs prior to those matters that the statute mandates be voluntary.[110] Ultimately, FERC concluded that FPA §202(a) deals with the coordination of facilities (i.e., facilities already in existence), whereas Order No. 1000 deals with the planning of new transmission facilities.[111]

b. FPA §217(b)4

FPA 217(b)(4) states:

> The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or

[108] 16 U.S.C. 824a(a)

[109] *See* Order 1000-A, ¶123.

[110] *See* id., ¶125. FERC further explains, in the case of transmission facilities, planning involves the consideration of various alternatives using economic and engineering analysis, whereas the operation of interconnected facilities involves operational cooperation, such as coordinated dispatch, among other things. *See* id., ¶129.

[111] *See* id., ¶135.

> financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.[112]

Some stakeholders argued that Order 1000 was inconsistent with the FPA by failing to meet the reasonable needs of load-serving entities ("LSEs"). FERC countered however, that the regional transmission planning reforms required by Order No. 1000 were consistent with §217(b)(4) because they will enhance the transmission planning process for all interested entities, including LSEs by supporting the development of needed transmission facilities that benefit LSEs.[113]

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[112] 16 U.S.C. 824q(b)(4).

[113] *See* Order 1000-A, ¶¶'s 168-170.

IV. A Survey of TP Order 1000 Compliance Filing Provisions

This section presents a snapshot of certain TP initial compliance filing provisions. TP Order 1000 compliance filings contain numerous substantive and consequential tariff proposals. Rather than provide a comprehensive review of each proposed tariff revision, this section selects a limited subset of compliance requirements deemed to be of particular interest to state regulatory commissions and focuses its attention on those. Further, this section is a snapshot because the process of compliance, particularly with a comprehensive new rule, is often a lengthy and on-going process requiring multiple rounds of compliance proposals, stakeholder protests and Commission decisions. Therefore, this section is *not* informed by Protests or Answers filed in responses to initial compliance filings, and is meant to provide an overview of certain initial TP compliance filing provisions *as individual TPs have presented them.*

A. PJM Interconnection, LLC

PJM adopted Order 1000 planning reforms in Schedule 6 of its Operating Agreement,[114] and Order 1000 cost-allocation reforms in its Schedule 12. Broadly stated, the aspects of PJM's compliance filing covered in this paper includes tariff amendments related to: (1) compliance with Order 890 Principles; (2) consideration and evaluation of PPRs; (3) the rights of non-incumbent transmission developers; and (4) cost allocation.[115]

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[114] According to Schedule 6, the mission of PJM is to "[E]nable the transmission needs in the PJM Region [to] be met on a reliable, economic and environmentally acceptable basis." PJM Schedule 6, §1.1. Each of PJM's new tariff sections refer back to its Operating Agreement.

[115] As noted above, PJM's compliance filing addresses many additional reforms but this section focuses on a subset.

1. Compliance with Order 890 planning principles

1. Coordination	Creation of Independent State Agency Committee (ISAC), §1.5.6(d) of Schedule 6 to discuss: (1) evaluation of transmission needs assumptions; (2) regulatory initiatives; (3) impacts of regulatory actions; and (4) proposed alternative sensitivities, assumptions and scenarios.[116]
2. *Openness*	In addition to increased stakeholder opportunities to provide input,[117] PJM proposes to post the following: (1) violations, system conditions and economic constraints and PPRs identified; (2) explanation why other suggested assumptions will not be evaluated; (3) all proposals submitted (after close of a proposal window); and (4) descriptions of proposed enhancements and expansions, including Supplemental Projects and state public policy projects.[118]
3. *Transparency*	A webpage detailing an entities' commitment to build a project identified in a regional plan including: (i) identification of the upgrade by project number; (ii) the required in-service date; (iii) a description of the project; (iv) the name of the constructing party; (v) the drivers; (vi) the status of the project; (vii) location of the facilities by state(s); (viii) the status of the project and (ix) the project's estimated costs.[119]
4. *Comparability*	The cancellation of the PATH and MAPP projects are clear indications of comparable NTA participation in PJM's planning process.[120]
5. *Economic Planning*	The Commission approved a metric formula that will account for the benefits to customers from reductions in both energy prices and capacity prices resulting from a proposed economic-based project.[121]

[116] *See* PJM Order 1000 Compliance Transmittal Letter, Docket No. ER13-198, October 25, 2012, pp. 19-20.

[117] *See* id., pp. 21-22 (referring to reforms accepted in Docket No. ER12-1178).

[118] *See* id., pp. 22-23.

[119] *See* id., p. 26.

[120] *See* id., p. 32

[121] *See* id., p. 34. The Commission also made revisions to §1.5.7 of Schedule 6 necessary to ensure the economic planning process integrates with all other drivers of transmission needs through the addition of the 24-month planning cycle. *See* id.

2. Consideration and evaluation of PPRs

PJM asserts that its compliance with Order 1000's PPR requirements is evident in three ways:

1. Integrated Market Design	PJM's Reliability Pricing Model Auction ("RPM") structure has yielded over 14,000 of demand response ("DR") and almost 900 MW of energy efficiency ("EE"). These resources are recognized in PJM's load forecasts and factored into reliability analyses, market efficiency analyses, and base case models used to determine transmission needs driven by PPRs.[122] PJM has also integrated over 7,000 MW of wind.
2. Consideration of PPRs	A. February 2012 Filing adopting tariff language to explicitly identify PPRs and Public Policy Objectives[123] B. February 2012 filing adopting revisions to Schedule 6 to expand analysis beyond the prescriptive "bright-line" tests used as part of its reliability and market efficiency analysis by adding scenario-based analyses that include consideration of PPRs.[124]
3. State Agreement Approach	Under §1.5.9 of Schedule 6, States can request that PJM study a project that is designed to address PPRs identified by a state or group of states; if the state(s) agrees to voluntarily assume responsibility for the allocation of all costs of the project the project will be included in the RTEP[125] either as a Supplemental Project or state public policy project.[126]

[122] *See* id., p. 38.

[123] *See* fn. 117, *supra*.

[124] *See* PJM Transmittal Letter, Docket No. ER12-1178, February 29, 2012. With these revisions, PJM states it is able to perform more extensive scenario planning analyses in its 2012 RTEP using a broader range of sensitivity studies and modeling assumptions that include public policy initiatives such as renewable resource integration related to RPS, demand response programs or other environmental initiatives, as well as "at risk" generation. Using the sensitivity studies, modeling assumption variations and scenario planning analyses, including Public Policy Objectives, PJM will be able to take into account, in its decision-making with respect to reliability and market efficiency drivers, potential changes in expected future system conditions and uncertainties arising from estimated times to construction transmission upgrades. *See* PJM Order 1000 Compliance Transmittal Letter, p. 41.

[125] Regional Transmission Expansion Plan

[126] *See* PJM Order 1000 Compliance Transmittal Letter, p. 46. PJM states that provisions are not needed for compliance but, instead, represent an optional and complimentary mechanism for the PJM states to utilize to submit state-approved public policy projects for inclusion in the RTEP. *See* id., p. 15.

3. Participation by non-incumbent providers

PJM states that its tariff does not contain a federal ROFR[127] and proceeds to discuss §1.5.8 of Schedule 6 which contains an opportunity for participation by non-incumbents in proposing transmission solutions. However, PJM TOs made a separate Order 1000-A Compliance Filing stating that the PJM Consolidated Transmission Owners Agreement ("CTOA") and the PJM Amended and Restated Operating Agreement ("OA") each contain provisions providing the PJM Transmission Owners with a ROFR and asserting that the Commission therefore cannot direct revisions to those agreements unless it finds the current provisions to be contrary to the public interest.[128]

PJM proposes three distinct categories of projects (long lead-time projects, short-term projects, and immediate-need reliability projects), and has developed proposal windows for each project type. PJM has also developed provisions outlining the technical and financial qualifications required to propose a solution to an identified need.

A non-incumbent transmission developer may submit a project proposal which, if included in the RTEP, may be designated to the project sponsor. PJM proposes proposal windows through which an entity who has *pre-qualified* as a Designated Entity may submit a project proposal and notify PJM whether or not such entity wishes to be designated rights to the project if the project is selected for inclusion in the RTEP. The potential for competitive solicitation of proposals exists in each of the three §1.5.8 project categories.[129]

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[127] FERC found in the *Primary Power* case that PJM Tariff does not contain a ROFR. *See* id., pp. 48-49.

[128] *See* Compliance Filing by Indicated PJM Transmission Owners Concerning *Mobile-Sierra* Protections for Right of First Refusal Provisions in PJM Agreements, Docket No. ER13-195-000, October 25, 2012, p. 2. A discussion of *Mobile-Sierra* concerns is contained in Section V of this paper. In addition, for a brief discussion of the *Mobile-Sierra* doctrine and Public Interest standard, please *See* Appendix C.

[129] *See* id., pp. 49-50.

<table>
<tr><th>Project Category</th><th>Description</th><th>Project Window[130]</th><th>Limitations on non-incumbent participation</th></tr>
<tr><td>Long Lead-Time
Proposed Sch. 6, §1.19A</td><td>Transmission enhancement/expansion with an in-service date greater than five years from the date the violations is identified.[131]</td><td>120-day window;
If no project selected, PJM holds additional proposal window;
If no project, PJM selects TP in zone where project located as Designated Entity.[132]</td><td rowspan="3">(i) The need to address reliability

and

(2) the time likely needed to complete a project based on the scope of any criteria violation.[133]</td></tr>
<tr><td>Short-Term
Proposed Sch.6 §1.41A.01</td><td>Transmission enhancement/expansion with an in-service date of greater than three years but no more than five years from the violation is identified.[134]</td><td>30-day window;
If no project selected, PJM designates incumbent TP in zone.</td></tr>
<tr><td>Immediate-Need Reliability
Proposed Sch.6, §1.15A</td><td>Reliability-based enhancement/expansion with an in-service date of three years or less from the date the violation is identified.[135]</td><td>Less than 30 days;
If no project chosen and reliability at issue, PJM designates incumbent TP in zone.</td></tr>
</table>

PJM notes the Commission's likely concern with designating the incumbent as the default owner rather than holding another proposal window or solicitation. PJM states, however that it has limited the use of the incumbent transmission owner as the default to those scenarios where, due to system reliability needs and time constraints, it would be impractical and even perhaps imprudent to hold another proposal window process.[136]

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[130] *See* id., pp. 69-70.

[131] *See* id., fn. 36.

[132] A Designated Entity is the entity designated by the Office of the Interconnection with the responsibility to construct, own, operate, maintain, and finance Immediate-need Reliability Projects, Short-term Projects, and Long-lead Projects pursuant to Section 1.5.8 of Schedule 6 of this Agreement. *See* proposed Sch. 6, §1.7A

[133] *See* id., p. 53. "The availability of such opportunities is limited only by: (i) the need to address reliability; and (ii) the time likely needed to complete a project based on the scope of any criteria violations."

[134] *See* id., fn. 37.

[135] *See* id., fn. 38.

[136] *See* id., pp. 58-59.

The technical and financial information required of project sponsors includes:

1. identifying information about the entity wishing to be designated;

2. the entity's technical and engineering qualifications, experience, previous record, capability to adhere to industry standards, ability to remedy emergency situations and experience in acquiring rights of way, and

3. the entity's financial liquidity.[137]

4. Cost allocation[138]

PJM supports the PJM TO filing and states that it adopts and relies on the Schedule 12 Filing to satisfy its Order No.1000 cost-allocation compliance requirements.[139] The TO filing made the following proposed amendments to PJM's existing cost-allocation methodology:

1. It redefined Regional Facility to include, in addition to facilities that operate at or above 500kV, facilities that operate at between 345kV and 500 kV.[140]

2. For regional and necessary lower-voltage facilities,[141] one-half of each project's cost is allocated on a postage-stamp basis (i.e., to zones on a load ratio share basis and to merchant transmission facilities in proportion to awarded Firm Transmission Withdrawal Rights), and the remaining half would be based on "Solution-Based" distribution factor ("DFAX") analysis for reliability-based projects and on each Zone's and each merchant transmission facility's share of the zonal decreases in load energy payments that result from the new facility for economic-based projects.[142]

3. The full cost of a reliability-based lower voltage facility will be allocated according to the Solution-Based DFAX analysis used for reliability-based regional facilities and necessary lower voltage facilities;[143] and the full costs of an

[137] *See* id., p. 64.

[138] According to PJM, due to the D.C. Court of Appeal's decision in *Atlantic City Electric Company, et al v. FERC*, 295 F.3d 1 (D.C. Cir. 2002), the TOs hold the exclusive and unilateral right to amend Schedule 12 (cost allocation rules) in PJM. *See* id., p. 75. The PJM TO's made their §205 filing on October 11, 2012 in Docket No. ER13-90.

[139] *See* PJM Order 1000 Compliance Transmittal Letter, p. 76.

[140] *See* id., pp. 76-77.

[141] Necessary lower-voltage facilities are those facilities that must be constructed to or strengthened to support facilities that are 500kV or above. *See* TO Filing, Docket No. ER13-90, p. 4.

[142] *See* PJM Order 1000 Compliance Filing Transmittal Letter, p. 77, (citing to TO filing, pp. 8-9).

[143] *See* id., p. 77.

economic-based lower voltage facility will be allocated based on the load payment reduction analysis used for economic based regional facilities and necessary lower voltage facilities.[144]

4. Finally, regional facilities and necessary lower voltage facilities that employ Direct Current ("DC") technology will be allocated using a hybrid methodology in which 50% of the costs are allocated on a postage-stamp basis and 50% are allocated to specifically identified beneficiaries. All of the costs of lower voltage facilities using DC technology will be allocated to specific beneficiaries.[145]

B. Midwest Independent System Operator

MISO amended its Attachment FF to establish a regional planning process resulting in a regional plan, and, on a regular basis, to identify and implement more efficient and/or cost-effective regional transmission solutions.[146] MISO believes that its existing processes significantly comply with the Order 1000 Rulings and that it needs only to supplement its tariff with certain posting requirements, particularly:

1. Explanations of determinations to evaluate or not evaluate PPR-driven transmission needs;

2. Information required to enable evaluations of reliability or operational impacts from proposed Merchant transmission facilities; and

3. Enrollment and listing of non-public entities that choose to become a part of MISO.[147]

In addition, while MISO submitted tariff reforms to comply with the non-incumbent transmission developer mandates in Order 1000, it cautions that FERC will likely not be able to overcome *Mobile-Sierra* restrictions in order to accept the revisions.[148] Finally, according to MISO, its planning process appropriately plans for and allocates the cost of transmission projects that address a variety of needs: [149]

[144] *See* id., p. 78.

[145] *See* id.

[146] *See* MISO Order 1000 Compliance Filing Transmittal Letter, Docket No. ER13-187, October 25, 2012, p. 3.

[147] *See* id., p. 4.

[148] *See* id., pp. 4-5.

[149] *See* id. In particular, MISO states that FERC has found that the MVP proposal enjoys broad state authority and stakeholder support, presents significant incentives to construct new transmission and allocates the costs of new transmission fairly to the market participants that use the MISO transmission grid and who will benefit from its maintenance and further development. *See* id.

Reliability Needs	Baseline Reliability Projects ("BRPs") or Multi-Value Projects ("MVPs")
Economic Needs	Market Efficiency Projects ("MEPs") or MVPs
Public Policy Requirements	MVPs (Criterion 1)[150]

Broadly stated, the aspects of MISO's compliance filing addressed in this paper include (1) compliance with the Order 890 planning principles, (2) transmission needs driven by PPRs, (3) regional participation, (4) regional cost allocation, and (5) non-incumbent developer participation.

1. Compliance with Order 890 planning principles

Openness	Attachment FF, §I.A.2.c – provides for sub-regional planning meetings open to all interested parties such as regulators, environmental agencies, load and generation developers.[151]
Transparency	Attachment FF, §I.A.13 – describes basis for planning decisions and methodology, criteria and process used to develop MTEP; §I.A.7 – describes procedures to collaborate with stakeholders to develop planning models; §I.A.8 – describes planning assumptions.[152]
Information Exchange	§I.A.8.b - details on the coincident peak load projection methods to be employed by MISO to model load demand for each entity; §I.A.8.d - how MISO will deal with Demand Response Resources ("DRRs") by incorporating relevant information into planning assumptions.[153]
Comparability	§I.A.8.d, DRRS will be evaluated comparably with Generation Resources to evaluate the quantity of energy that can reliably be expected from DRRs and DRRs will be evaluated as equivalent to Generation Resources as solutions for peak load conditions.[154]
Dispute Resolution	§I.A.14 – three step process: negotiation, mediation, and arbitration; Business Practice Manual provides Issue Resolution Process for

[150] Criterion 1 – [An MVP] must be developed through the transmission expansion planning process for the purpose of enabling the Transmission System to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation. The MVP must be shown to enable the transmission system to deliver such energy in a manner that is more reliable and/or more economic than it otherwise would be without the transmission upgrade. *See Order Conditionally Accepting Tariff Revisions*, Docket No. ER10-1791-000, December 16, 2010, ¶29.

[151] *See* id., p. 9.

[152] *See* id., pp. 9-10. "MTEP" stands for Midwest Transmission Expansion Plan.

[153] *See* id., p. 10.

[154] *See* id., p. 11.

	planning and cost-allocation issues that arise in MTEP development process.[155]
Economic Planning	20-year planning horizon; stakeholder input regarding near-term congestion issues; enables MISO to review historic congestion data and develop prioritized study scopes.[156]

2. Transmission needs driven by PPRs

To demonstrate how it addresses transmission needs driven by PPRs, MISO describes MVPs, which include transmission projects that are:

> for the purpose of enabling the transmission system to reliably and economically deliver energy in support of documented energy policy mandates or laws that have been enacted or adopted through state or federal legislation or regulatory requirement that directly or indirectly govern the minimum or maximum amount of energy that can be generated by specific types of generation.[157]

MISO revised Attachment FF to provide that MISO will post on its website an explanation of: (i) *which* transmission needs driven by PPRs will be evaluated for potential solutions in the local or regional transmission planning process; and (ii) *why* other suggested transmission needs will not be evaluated.[158] In addition, MISO states that it explores multiple future scenarios through various studies included in the MTEP analysis in an effort to determine the robustness and long-term value of the proposals made in the MTEP.[159] These future scenarios may consider public policies that have not yet been enacted as laws, regulations, or mandates to ascertain the robustness and/or economic value of transmission projects recommended in the MTEP.[160]

3. Participation in the planning region

According to MISO, the proposed Tariff revisions provide a clear process for entities, including non-public-utility TPs, to enroll to participate in MISO's transmission planning region for purposes of Order 1000 compliance.[161] Entities wishing to enroll in the MISO planning process are required to execute the Transmission Owners Agreement and become a MISO Transmission Owner. Further, within a reasonable period of time from the execution of the Transmission Owners Agreement, such entities will be obligated to turn the functional control of

[155] *See* id., pp. 11-12.

[156] *See* id., p. 12.

[157] *See* id., p. 13.

[158] *See* id., p. 14.

[159] *See* id.

[160] *See* id.

[161] *See* id., p. 15.

their existing transmission facilities over to MISO and take service under the MISO Tariff for all loads that are physically located within the MISO footprint.[162]

MISO also proposes tariff language describing the participation of merchant transmission developers and the state regulatory agencies:

[162] *See* id.

Merchant Transmission Developers[163]	Role of State Regulatory Agencies[164]
Information and data requirements required to support studies by MISO to determine reliability and operational impacts:	Organization of MISO States ("OMS") Committee role in transmission planning, resource adequacy and cost allocation codified in the Transmission Owners Agreement.
- Descriptions and key technical parameters for proposed facilities - Points of interconnection - Proposed facility models	- Input on planning principles/objectives - Scope elements - Modeling inputs/assumptions - Cost/benefit analysis

4. Regional cost allocation

MISO states that the two project types that can be selected in the regional plan for purposes of cost allocation are MEPs and MVPs.[165]

Cost-allocation principle	MVP Treatment	MEP Treatment
Principle 1:[166] determination of beneficiaries	MVP benefits are spread broadly across the footprint; 100% of their costs are allocation regionally	MEPs focus on congestion relief; 20% allocated regionally and 80% allocated based on the distribution of the adjusted production cost savings across the MISO Local Resource Zones
Principle 2:[167] no benefit = no cost allocation	Consideration of multiple future scenarios to estimate benefits.	Future scenario analysis Benefit metric: "Weighted Future/No Loss"

[163] *See* id., p. 15.

[164] *See* id., p. 16. The amendments also codify the requirement that MISO will provide a prompt and clear response to the OMS Committee in response to issues raised. Moreover, the amendments provide for a process for the OMS Committee to request that MISO reconsider a transmission project submitted for regional cost allocation in the MTEP under certain circumstances. Finally, these amendments provide the OMS Committee with the opportunity to request and receive reasonable assistance from MISO in developing its input into the MTEP. Id.

[165] *See* id., p. 22. Projects that are not included in the regional transmission plan for purposes of cost allocation include (i) local transmission facilities whose costs are recovered from load in the pricing zone where the transmission facility is located; (ii) projects that are funded by a market participant(s) requesting the facility; and (iii) Generation Interconnection Projects, which are excluded from the scope of Order No. 1000. Id. MISO and the MISO Transmission Owners made a separate filing proposing modifications to the existing Baseline Reliability Project cost allocation provisions to provide for 100% of the costs of the BRPs to be allocated to the pricing zone where the BRP is located. *See* Docket No. ER13-186-000, October 25, 2012.

[166] *See* id., pp. 22-23.

[167] *See* id., p. 24.

Principle 3:[168] Cost-benefit threshold	Cost/Benefit threshold = 1.0 for Criterion 2 or Criterion 3	Cost/Benefit Threshold = 1.25
Principle 5:[169] transparency	Allocation/benefits determination – Cost-allocation methods applied – Results of analyses -	Specified in tariff Open stakeholder planning process Documented in studies and recommendations embodied in annual MTEP

5. Non-incumbent developer participation

MISO asserts that its Transmission Owner's Agreement is protected by the *Mobile-Sierra* doctrine and urges the Commission to reject tariff revisions related to the removal of the ROFR unless it finds that the TO Agreement is not a *Mobile-Sierra* contract, or that the TO Agreement is a *Mobile-Sierra* contract but that the public interest standard has been met.[170]

However, MISO includes proposed tariff revisions eliminating the ROFR and details process requirements for projects excluded from the ROFR-elimination requirement, non-incumbent participation and the role or states.

a. Proposed reforms

According to MISO, approved projects covered by the Commission's directive to eliminate federal ROFR will be classified as Open Transmission Projects, for which MISO will issue Transmission Proposal Requests, in response to which both non-incumbent transmission developers and incumbent TPs may submit New Transmission Proposals.[171] Pursuant to proposed revisions to the Transmission Owners Agreement, for transmission projects selected in the regional plan for purposes of cost allocation (MEPs and MVPs), MISO will select the entity to construct each such project using an inclusive evaluation approach. Other provisions of the Transmission Owners Agreement on obligations to construct "local" facilities (not regionally planned and not regionally cost allocated) will be retained.[172]

[168] *See* id., p. 25. The three MVP Criteria are described in Tariff FF (*see* p. 245 of MISO Order 1000 Compliance Filing PDF).

[169] *See* id., p. 27.

[170] *See* id., p. 39. Please *see* Appendix C which contains a discussion of the *Mobile-Sierra* doctrine and the Public Interest Standard.

[171] *See* id., p. 40. MISO's project selection process remains a combination of the "bottom-up" identification of projects in the local planning processes of Transmission Owners, and MISO's "top-down" consideration of both locally identified projects and those identified through other means, in light of regional needs. *See* id., p. 39. For a discussion of the "top-down" and "bottom-up" planning approaches, *see* Section V of this paper (referencing Order 1000, ¶255).

[172] *See* id., pp. 40-41.

b. Exclusions from ROFR elimination requirement[173]

Facility Type or Policy	Determination of Local or Regional	Treatment	
		Local	Regional
Local Facility		x	
Multi-Owner Transmission Facility[174]	In all 11 joint-pricing zones a single Transmission Owner owns at least 75% of the gross transmission plant in that pricing zone	x	
Upgrades to Existing Facilities	new transmission line sections on new right-of-way are new transmission facilities when the length of such new transmission line sections exceeds 20 contiguous miles	< 20 mi.	> 20mi.
State ROFRs	Conformity with State Process	x	

c. Process for non-incumbent participation

Upon approval of an MTEP by the MISO Board, MISO will develop and post on its website, within thirty days, a request for proposal for each transmission project that contains new transmission facilities that could potentially be constructed by non-incumbent transmission developers.[175]

[173] *See* id., pp. 45-50.

[174] Regarding multi-owner facilities, MISO explains that eleven of the 24 pricing zones contain the transmission facilities of more than one Transmission Owner (referred to in MISO as "joint pricing zones" (See id., p. 45).

[175] These projects are referred to as Open Transmission Projects (section 1.477a) in the Tariff and the request for proposals is referred to as a Transmission Proposal Request (section 1.671b). *See* id., pp. 51-52. Regarding reevaluation, variance analysis will determine if proposed changes to developer commitments may cause harm to the system, and it will flag changes of this nature for full reevaluation. *See* id., p. 58.

Developer requirements in response to new transmission proposal requests:[176]	- Execution of Binding Proposal Agreements - Execution of the Transmission Owners Agreement - Abidance to terms in MISO Tariff
Qualifications:[177]	- Execute required agreements such as the Transmission Owners Agreement - Comply with applicable laws and regulations, including those required by NERC - Satisfy all FERC planning criteria - Submit all required data
Evaluation process if states decline to select developer:[178]	- Evaluate each New Transmission Proposal submitted by a Qualified Transmission Developer - Select the New Transmission Proposals for implementation based on evaluation criteria specified in the Tariff - Post the selected Qualified Transmission Developer within 180 days of the due date for submission of New Transmission Proposals
Criteria for Evaluation and Selection[179]	- Cost and reasonably descriptive facility design - Project implementation capabilities - Operations, maintenance, repair, and replacement capabilities - MISO planning process participation

C. Southwest Power Pool

SPP proposes to retain the current language in its Attachment O, which governs the Integrated Transmission Planning ("ITP") process and SPP's development of the annual transmission expansion plan ("STEP"). SPP also proposes to retain its current cost allocation set forth in Attachment J, including its Highway/Byway Balanced Portfolio cost-allocation methodologies.[180] As such, SPP describes how its tariffs are consistent with or superior to the Order 1000 Ruling requirements as allowed for in the Order.[181]

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[176] *See* id., p. 54.

[177] *See* id.

[178] *See* id., p. 56.

[179] *See* id., p. 55.

[180] *See* SPP Order 1000 Compliance Filing, Docket No. ER13-366-000, November 13, 2012, p. 13.

[181] *See* fn. 21, supra.

SPP asserts that its Membership Agreement is protected by the *Mobile-Sierra* doctrine, stating that all available evidence suggests that transmission planning under the current transmission construction and ownership rights in SPP is benefitting, as opposed to "seriously harming," the public interest.[182] However, in the case the Commission determines that the Membership Agreement is not a *Mobile-Sierra* contract, or that the Public Interest standard has been met, SPP conditionally proposes to adopt a new Attachment Y to govern the Transmission Owner Designation Process both for projects "selected in the regional transmission plan for purposes of cost allocation" and other transmission facilities.[183] In addition, SPP has conditionally adopted revisions to move the current provisions governing designation of Transmission Owners from Attachment O to Attachment Y, and proposed new provisions establishing the Transmission Owner Selection Process for Competitive Upgrades, a competitive solicitation process for transmission facilities selected in the regional transmission plan for purposes of cost allocation.[184]

1. Regional planning process

According to SPP, its ITP process is an iterative, three-year planning process that includes 20-Year, 10-Year, and Near-Term Assessments designed to identify transmission solutions that address both near-term and long-term transmission needs.[185]

20-Year Assessment	Identify transmission solutions needed in year 20 Determines cost-effectiveness over 40-year time horizon
10-Year Assessment	Focuses on 10-year planning horizon Assesses cost effectiveness over 40-year time horizon
Near-Term Assessment	Solutions required to maintain reliability needed in near-term Planning horizon shorter than 10 years

Also according to SPP, under Attachment O, the RTO conducts a regional transmission planning process that produces a regional transmission plan, and evaluates "in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process.[186]

[182] *See* SPP Compliance Filing, p. 14. Please see Appendix C for a brief discussion of the *Mobile-Sierra* doctrine and the Public Interest standard.

[183] *See* id., p. 15.

[184] *See* id.

[185] *See* id., pp. 16-17.

[186] *See* id., pp. 17-18.

2. Compliance with Order 890 principles

Coordination[187]	Stakeholder working groups provide technical advice/assistance; Meetings at least quarterly; Open participation in planning summit meetings
Openness[188]	Planning meetings open to all entities including regulatory bodies; Meeting notices posted on website; Confidentiality/CEII concerns addressed
Transparency[189]	Methodology, criteria, processes used to develop transmission plans made available; Disclosure methodology made available on website
Information Exchange[190]	Provides guidelines and schedules for submittal/exchange of customer data in order to conduct annual planning processes
Comparability[191]	Identifies metrics used in determining cost-effectiveness, and evaluates alternatives (generation, demand response, Smart Grid, energy efficiency) based on cost-effectiveness.
Economic Planning Studies[192]	Attachment O: describes how input will be solicited from stakeholders on economic upgrades to be evaluated as Balanced Portfolios; Details economic upgrade criteria; Determination of costs/benefits and conditions; Allows high-priority study requests.

3. Transmission needs driven by PPRs

SPP states that it substantially complies with the Order 1000 directives regarding consider of transmission needs driven by PPRs.[193] Section III.6 of Attachment O of the Tariff establishes "Policy, Reliability, and Economic Input Requirements to Planning Studies," which include, among other things, renewable energy standards, energy efficiency requirements, other

[187] *See* id., p. 19.

[188] *See* id., pp. 19-20.

[189] *See* id., pp. 20-21.

[190] *See* id., p. 21.

[191] *See* id., p. 22. The Commission notes that tariff language could state that solutions will be evaluated against each other based on a comparison of their relative economics and effectiveness of performance.

[192] *See* id., p. 23. Under the Balanced Portfolio methodology, SPP evaluates a group, or portfolio, of economic upgrades to be included in the STEP, rather than evaluating the benefits of individual upgrades. *See* id., p. 31.

[193] *See* id., p. 25.

relevant environmental or government mandates, and other requirements identified in the stakeholder process.[194]

However, SPP offered the following proposed tariff revisions for clarification:[195]

PPRs Defined – Tariff §I.1	Requirements established by local, state, or federal laws or regulations, including duly enacted statutes or regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level
Working Group reform - §II.2.a.vi.	Review and development of the list of transmission needs driven in whole or in part by PPRs for which transmission solutions will be evaluated
Local planning processes - §II.5.vi.	Must provide for identification and evaluation of transmission needs driven by PPRs.
Assessment Study Scope - §§§III.3.g, III.4.g, III.5.e.	Explanation of which needs driven by PPRs will be evaluated for potential solutions, along with an explanation of why other suggested needs will not be evaluated.
All transmission solutions including those driven by PPRs - §III.8.c.	SPP will determine if there is a more comprehensive regional solution

4. Regional cost allocation

SPP states that its existing cost-allocation methodologies, Highway/Byway approach and Balanced Portfolio, comply with the Commission's regional cost-allocation requirements and six cost-allocation principles.[196]

Methodology	Voltage	Cost Allocation
Highway/Byway	EHV – 300kV and above Lower Voltage – > 100 kV < 300 kV Low Voltage - < 100 kV	100% on regional basis 1/3 on regional basis 2/3 to host transmission pricing zone 100% to host zone

[194] *See* id., pp. 25-26. SPP states that given the integrated nature of the ITP process, it does not separately plan transmission facilities to address needs driven by PPRs, but instead includes such requirements as inputs to planning studies and analyzes potential solutions in accordance with the assessment study scope. *See* id., p. 26.

[195] *See* id., pp. 24-27.

[196] *See* id., p. 30.

Designated Resources[197]	300 kV and above All other facilities	100% on regional basis 2/3 on regional basis 1/3 to transmission customer
Balanced Portfolio[198]	345 kV or higher, but other voltages allowed if conditions met.	100% on regional basis.

5. Compliance with regional cost allocation principles[199]

Principle 1: determination of beneficiaries	Highway/Byway and Balanced Portfolio Approaches accepted by Commission.
Principle 2: no beneficiary = no cost allocation	"unintended consequences" provision requires SPP to review the Highway/Byway methodology and factors on a regular basis for any long-term imbalance in costs/ benefits.
Principle 3: Cost-benefit threshold	Highway/Byway = no threshold Balanced Portfolio = 1.0 benefit/cost ratio
Principle 5: Transparency	SPP's open planning process promotes full transparency; Because costs are allocated under bright-line voltage criteria through the Highway/Byway methodology or to the region-wide revenue requirement for approved Balanced Portfolios, cost allocation is fully transparent.
Principle 6: Cost-allocation methods	SPP's cost-allocation methodologies do not generally distinguish among transmission facility "types" (i.e., reliability, economic, or public policy) for purposes of cost allocation.

[197] Designated Resources are designated generation resources owned, purchased or leased by a Transmission Customer to serve load in the SPP region. Designated Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Transmission Customer's load on a non-interruptible basis. *See* id., fn. 160.

[198] Under the Balanced Portfolio methodology, SPP evaluates a group, or portfolio, of economic upgrades to be included in the STEP, rather than evaluating the benefits of individual upgrades. To be included in the initial phase of planning for a Balanced Portfolio, an economic upgrade must include a 345 kV or higher facility. *See* id., p. 31.

[199] *See* id., pp. 32-37.

6. Non-incumbent developer requirements[200]

According to SPP, the Commission lacks the authority to order modification of the Membership Agreement to eliminate existing transmission construction rights and obligations, absent demonstrating that such a mandate complies with the public interest standard of review under the *Mobile-Sierra* doctrine. However, it filed conditional revisions to its tariff to comply with the Order 1000 Rulings on non-incumbent participation. Specifically, SPP proposed to adopt a new Transmission Owner Selection Process through which it will identify the appropriate entity to construct each Competitive Upgrade approved by the Board of Directors.[201]

Facility Type	Definition	Qualification Process[202]	Evaluation
Competitive Upgrades	- ITP Upgrades or high priority upgrades - nominal operating voltage of 300 kV or greater - not a rebuild of an existing facility and does not use rights-of-way where facilities exist - selection of transmission owner does not violate state law [203]	- submission of an application and fee - Retain QRP[204] status for 5 years absent material change - independent IEP[205] will evaluate proposals from incumbent/non-incumbent	- willingness to sign membership agreement - meets financial criteria - meets managerial and safety criteria - through the project tracking process SPP will track the costs of approved transmission facilities, including Competitive Upgrades, and may reevaluate such facilities if costs exceed a desired bandwidth. - entities submitting DPPs[206] during the planning process are awarded 100 incentive points in the Selection Process if their DPP is selected for construction by the Board of Directors, increasing the incentive for entities to bring more efficient and cost-effective solutions to the planning process.

[200] As SPP's proposed tariff provides the details of its conditional amendments regarding third party participation, this section will broadly address the competitive upgrade process and cost allocation to multi-transmission owner zones, but ***will not address*** each conditional revision to the membership agreement or tariff such as the detailed revisions to the selection process for competitive upgrades, incumbent transmission owner designation process, notification to construct, project tracking, revisions to attachment O or upgrades to address short-term reliability needs.

[201] *See* id., pp. 57-61.

[202] As described in Tariff §V.B.4.a, *see* id., pp. 70-74.

[203] *See* SPP Compliance Filing, p. 72.

[204] Qualified RFP Participant

Lower-voltage Facilities[207]	Byway: greater than 100 kV and less than 300 kV Low-voltage facilities: 100kV and below	retain existing Transmission Owner Designation Process for Byway facilities and low voltage facilities	

SPP states that its conditional proposal is consistent with Order No. 1000 because it eliminates federal rights of first refusal for truly regional projects as defined in the Highway/Byway Order, while preserving an incumbent utility's right and obligation to construct local transmission facilities as defined in the Highway/Byway Order.[208]

7. Multi-transmission provider zones

Responding to ¶424 of Order 1000-A,[209] SPP stated that five out of its 17 zones are multi-transmission owner zones and that the cost allocation to these zones is local, just as it would be for the cost of an identical transmission facility that is allocated to one of the twelve zones consisting of only one Transmission Owner's facilities.[210] SPP asserts that cost allocation in these instances should be local due to the following reasons:

1. The small geographic scope of zones in comparison to the entire SPP footprint;

2. The local investment nature of zones within the SPP system;

3. The Commission's determination that such allocation is local;[211] and

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[205] Industry Expert Panel

[206] Detailed project proposal (*see* p. 402 of SPP Compliance Filing PDF).

[207] Due in part to stakeholder consensus, SPP states that it will treat multi-provider zones as local for lower-voltage facilities, and explains that notwithstanding the language in Order No. 1000-A that "*[i]n general*, any regional allocation of the cost of a new transmission facility outside a single transmission provider's retail distribution service territory or footprint . . . is an application of the regional cost allocation method and that new transmission facility is not a local transmission facility," the Commission already has determined in the Highway/Byway Order that facilities allocated 100% to a single SPP zone or Byway facilities are local and provide local benefits. *See* SPP Order 1000 Compliance Filing Transmittal Letter, p. 58. *See also SPP Highway/Byway Order*, 131 FERC ¶ 61,252 (June 17, 2010).

[208] *See* id.

[209] While in general, any allocation of the cost of a new transmission facility outside of a single provider's territory is an application of the regional cost allocation method, the Commission recognized that special consideration is needed when a small transmission provider is located within the footprint of a larger provider.

[210] *See* SPP Compliance Filing, p. 63.

[211] *See* id., p. 66 (referring to SPP Highway/Byway Order, *See* fn. 207, *supra*).

4. Differentiating between single zones and multi-owner zones would cause undue discrimination.

D. New England Independent System Operator

New England ISO structured its Order 1000 compliance filing in a manner which provided 1) background about the success of its existing structure, 2) a description of the Transmission Owners Agreement ("TOA")[212] and an assertion that it is protected by the *Mobile-Sierra* doctrine;[213] 3) the elements of its primary compliance filing, and 4) elements of its contingent compliance filing, submitted in the event that the Commission finds that the existing planning process for reliability and market efficiency are contrary to the public interest.[214] Proposed revisions were made in Attachment K to ISO-New England's OATT.

[212] ISO-NE has operating authority over *all* facilities comprising the New England Transmission System. These facilities include Pool Transmission Facilities ("PTF"), Non-Pool Transmission Facilities ("Non-PTF"), Other Transmission Facilities ("OTF"), and Merchant Transmission Facilities ("MTF"), all of which are used for the provision of transmission service under the ISO-NE OATT. *See* id., fn. 44.

[213] For a discussion of the Mobile-Sierra Doctrine and the Public Interest Standard, please *see* Appendix C.

[214] *See* ISO-New England Order 1000 Compliance Filing, Docket No. ER13-196-000, October 25, 2012, p. 8. This paper summarizes only items 3 and 4.

1. Elements of the primary compliance filing

a. Compliance with Order 890 planning principles

Coordination[215]	Planning Advisory Committee ("PAC"): - facilitates development of the Regional System Plan ("RSP") i. reviewing study assumptions ii. inputs regarding results of systems needs assessments iii. identifies/prioritizes economic planning studies. - provides access to models and data used in planning process - information included in website posting (for project commitments)
Openness[216]	- Open to all affected and any other interested parties - Protective of all confidential and CEII data
Transparency[217]	- Availability of data: notice provided of Needs Assessments and other studies, timetables, and methodologies, criteria and protocols used to develop RSP - NTAs – "Market Responses", including DR resources, can displace regulated transmission solutions, are accounted for in Needs Assessments.
Information Exchange[218]	Information regarding generation and DR resources available through ISO generation interconnection program, demand and load-response program and forward capacity market ("FCM").
Comparability[219]	Any stakeholder can request Needs Assessment or economic studies and all market responses treated comparably.
Regional Participation[220]	The ISO coordinates planning activities with the PTOs and with OTF and MTF owners. ISO uses the Local System Plan ("LSP") process in planning for non-PTF.
Economic Planning Studies[221]	Stakeholders may request Needs Assessments for upgrades that could result in: - net reduction of total production cost to supply system load; - reduced congestion; or -integration of new resources/loads

[215] *See* id., p. 34.

[216] *See* id., p. 35.

[217] *See* id., pp. 35-37.

[218] *See* id., p. 38.

[219] *See* id., pp. 38-39.

[220] *See* id., p. 40.

[221] *See* id., p. 41.

b. Regional cost allocation

The cost-allocation provisions for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades are based on whether these transmission facilities meet the ISO-NE Tariff definition of PTF or Non-PTF, where PTF are considered regional transmission facilities and non-PTF are considered local transmission facilities.[222]

Facility	Characteristics
Pooled Transmission Facility	i. Regional ii. If upgrade, 115kV or above iii. meet non-voltage criteria in OATT
Non-Pooled Transmission Facility	i. Local ii. Needed to serve local load only iii. Generator leads iv. TFs that interconnect non-PTF to PTF

c. Compliance with cost-allocation principles

Principle 1:[223] Beneficiaries	PTF system is the "highway" benefitting the entire region.
Principle 2:[224] No benefit = no allocation	Localized cost process ensures that any PTF costs designed primarily to have a local benefit are not allocated to all regional customers.
Principle 3:[225] Benefit to cost threshold	For market efficiency transmission upgrades Benefit to cost threshold < 1.25

d. Participation by non-incumbent

Solution Studies enable stakeholders to propose projects to resolve system needs, and a chosen solution may differ from that proposed by a Pooled Transmission Owner ("PTO"), OTO or MTO. While projects built by PTOs as designated by the ISO in accordance with the TOA, the process preserves an avenue for participation by non-incumbents.[226] Construction and ownership opportunities are available to non-incumbents in the context of Public Policy Transmission Upgrades ("PPTU").[227]

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[222] *See* id., pp. 42-44.

[223] *See* id., p. 44.

[224] *See* id.

[225] *See* id., p. 45.

[226] According to ISO, these provisions provide for the opportunity for any stakeholder, including non-incumbent transmission companies, to propose plans in the stakeholder process, but not to construct and own them in a competitive process. *See* id., p. 48.

[227] *See* id., p. 49.

e. Public policy transmission planning and cost allocation

The compliance filing proposes to utilize the New England States Committee on Electricity ("NESCOE") as the primary body to identify state and federal public policies that may drive the need for transmission in New England.[228] NESCOE will solicit input on state and federal public policies from the PAC and will submit study requests to the ISO including an explanation of which public policies should be evaluated and why others should not be evaluated.[229]

Once public policies are identified, the ISO will conduct a Public Policy Transmission Study to identify solutions and a follow-on study to narrow the scope of possible solutions.[230] NESCOE will then provide ISO with options states are interested in exploring, identified through submission to a Stage One competitive solicitation.[231] The ISO will review Stage One Proposals to determine whether they have submitted required data and are responsive to state needs.[232] The ISO will share its review results with NESCOE who then requests State Two Solution Study costs for detailed engineering studies. After an ISO assessment of reliability benefits, a Public Policy Transmittal enables the ISO to place the project into the RSP as a PPTU.[233] Qualification criteria incident to participation by non-incumbent developers in PPTUs include:[234]

Qualified Transmission Project Sponsor ("QTPS") Qualification Criteria
Capabilities to finance, license, construct and operate and maintain PPTU
Financial resources
Technical/engineering qualifications/experience
Previous record of applicant
Demonstrated capability
Ability to comply with reliability standards
Legal status
Satisfaction of state legal and regulatory requirements
Experience acquiring rights-of-way
Ability to meet development/completion schedules
Ability to assume liability for losses

[228] *See* id., p. 51.

[229] *See* id.

[230] *See* id., p. 52.

[231] *See* id. §4.A.5 of the tariff sets out criteria for information to be submitted.

[232] *See* id., pp. 54-55.

[233] *See* id., p. 56.

[234] *See* id., pp. 58-59. As provisions are detailed in the ISO tariff, this section will not address the Non-incumbent Transmission Developer Operating Agreement ("NTDOA") or the treatment of costs associated with the Public Policy Study Process and Projects

2. Elements of the contingent compliance filing

According to ISO, the contingent compliance filing provides a planning process based on dueling submissions for identified reliability needs where the year of need is more than five years from the completion of the needs assessment study.[235] The five-year threshold should offer significant opportunities for project submittal by QTPSs,[236] according to ISO. ISO states that development of the contingent provisions was required by Order 1000-A for use in the event that the Commission makes a finding that the public interest standard requires overturning the current reliability planning process.[237]

In increasing the assessment period beyond the five-year threshold so that non-incumbent provider proposals can be evaluated in a competitive format, ISO suggests that it is not acceptable to delay projects by one or two years for additional processes to play out before beginning the siting process.[238]

The process begins with a public notice inviting any QTPSs to submit Phase One Proposals to offer system solutions. PTOs would also submit Phase One Proposals.[239] The ISO would evaluate the proposals and can exclude from Phase Two consideration projects it has deemed uncompetitive in terms of cost, electrical performance, system expandability or feasibility.[240] ISO would select its Phase Two Solution, with input from the PAC, based upon these same criteria.[241]

E. New York Independent System Operator

New York ISO's Attachment Y contains the region's transmission planning and cost-allocation provisions.[242] Known as the Comprehensive System Planning Process ("CSPP"), the planning process includes the following elements:

[235] *See* id., p. 65.

[236] Qualified Transmission Project Sponsor

[237] *See* id., p. 66. According to ISO, the contingent compliance filing makes revisions to the TOA, though they were not voluntary agreed to and would only apply if the Commission rejects the asserted *Mobile-Sierra* rights.

[238] *See* id., p. 67.

[239] *See* id., pp. 67-68. Phase One Proposal criteria are included in §4.3(b) of the tariff. *See* p. 68.

[240] *See* id., p. 69. QTPSs would submit §205 filings to establish charges and be entitled to recover prudently-incurred costs (tariff §4.3(h)). *See* id.

[241] *See* id., pp. 70-71.

[242] *See* New York ISO Order 1000 Compliance Filing, Docket No. ER13-102-000, October 15, 2012.

Local Transmission Planning Process ("LTPP")	Each TO posts and accepts comments on its local area plans
Reliability Planning Process ("RPP')	- Reliability Needs Assessment ("RNA") - Comprehensive Reliability Plan ("CRP") - identifies reliability needs over 10-year planning horizon and evaluates market-based solutions as well as regulated solutions
Congestion Analysis and Resource Integration Study ("CARIS")	- overall analysis of economic benefits of relieving congestion - process for developers to propose projects to resolve congestion and to request evaluation of eligibility for cost allocation under the tariff.

According to NYISO, CSPP meets or exceeds Order 1000 requirements because it:

1. is market-based, striving to achieve market-based solutions to reliability and economic needs;

2. is open and transparent, engaging regulators, Market Participants and other stakeholders;

3. considers all resources as potential solutions to identified needs, including transmission, generation and demand response;

4. provides for the allocation of costs of proposed solutions to identified reliability and economic needs to project beneficiaries;

5. does not include a ROFR for incumbent transmission owners for transmission projects to address regional needs;

6. results in a regional transmission plan that evaluates solutions for identified reliability and economic needs in the region;

7. complies with the Order No. 890 transmission planning principles; and

8. complies with the Order No. 1000 regional cost-allocation principles.[243]

NYISO proposes to become fully compliant with Order 1000 by adding the following additional provisions to its tariffs:

1. A new planning process to consider transmission needs driven by PPRs;

2. The inclusion of entity qualification and project information criteria in the tariff;

3. The consideration of consequences of identified transmission solutions on other regions;

[243] *See* id., p. 1.

4. The evaluation of regional transmission projects that may meet the regional bulk power system needs more efficiently or cost-effectively than projects identified in local transmission plans; and

5. The inclusion of the six Order No. 1000 cost-allocation principles.[244]

1. Compliance with Order 890 planning principles[245]

Coordination	- Full opportunity for interested parties to participate in CSPP (RNA, CRP and CARIS) - Draft RNA, CRP, and CARIS Phase I and CARIS project-specific reports provided to stakeholders for review
Openness	- Open to all affected parties including all transmission and interconnection customers and state authorities - Protection of confidential and CEII data - Public information sessions provide exposure to the market place and all interested members of the public regarding the identified reliability and economic needs and the planning studies that are developed pursuant to the CSPP
Comparability[246]	When evaluating proposed solutions to Reliability Needs, all resource types shall be considered on a comparable basis as potential solutions to the Reliability Needs identified: generation, transmission and demand response
Transparency	- Attachment Y provides that all information be made available to Market Participants and other interested parties through the ESPWG[247] and TPAS[248] committees. - NYISO also makes available to any interested party sufficient information to replicate the results of the draft RNA - Data needed to replicate the CRP and CARIS results will be made publicly available.
Information Exchange	- Attachment Y requires that the NYISO gather and share data and assumptions to be used in the development of RNA, CRP and CARIS - NYISO and the appropriate transmission owner(s) are to assist any party in developing a market-based solution or an alternative regulated solution to a reliability need by providing "any party who wishes to develop such a response access to the data that is necessary to develop its response.

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244 *See* id., p. 2.

245 *See* id., pp. 19-27.

246 *See* id., p. 22. The CRPP states that the evaluation of all resources will be analyzed using the same models and procedures and the calculation and analyses will be consistent with the timing, type, and magnitude of the solution being evaluated. *See* id., p. 23.

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Economic Planning	- CARIS Phase I consists of a series of three congestion and resource integration studies of the most congested transmission corridors in the New York system, and measures the cost of congestion as the change in bid production costs resulting from transmission congestion - In CARIS Phase II, if a developer proposes a transmission project that has a favorable benefit-cost ratio, costs at least $25 million, and the project receives a positive vote from at least 80 percent of the designated beneficiaries, the costs of the project are eligible for recovery from beneficiaries.

NYISO states that in the CARIS Phase I process, the NYISO analyzes the impacts of generic transmission, demand response and generation projects on congestion. However, the NYISO's Tariff provides cost allocation only for transmission solutions that are proposed as specific projects evaluated under the CARIS Phase II process to relieve congestion on the transmission system identified in the CARIS Phase I process.[249]

2. Participation by Merchants

In order for a Merchant to have a solution considered in the regional planning process for purposes of cost allocation, its submission must include the following:

1. evidence of a commercially viable technology,
2. a major milestone schedule,
3. evidence of site control, or a plan for obtaining site control,
4. the status of any contracts that are under negotiation or in place,
5. the status of any interconnection studies and an Interconnection Agreement,
6. the status of any required permits,
7. the status of equipment procurement,
8. evidence of financing, and
9. any other information requested by the NYISO[250]

3. Non-incumbent developer participation

According to the NYISO, the ISO's tariffs do not contain any ROFR provisions and specifically allow for any developer to submit proposals for transmission reliability solutions, as well as economic transmission projects.[251]

[249] *See* id., p. 23.

[250] *See* id., p. 29.

4. Cost allocation methodologies[252]

Regulated Reliability Solutions	Step One	- areas have locational capacity requirements ("LCR") for installed capacity - cost allocated to LSEs in those zones
	Step Two	- reliability simulations model run to determine if loss of load expectation ("LOLE") less than .1 days/year - costs allocated to all load zones based on their coincident peak load contribution.
	Step Three	- Binding interface test identifies binding transmission constraints that are preventing the deliverability of capacity across the region - costs allocated accordingly.
Regulated Economic Solutions	eligible for cost recovery where they meet the following thresholds: (1) the benefits must exceed the costs; (2) the total capital cost of the project must exceed $25 million; (3) a supermajority of the project's beneficiaries support the project; and (4) the Commission approves the project's costs as just and reasonable.	Cost allocation among beneficiaries is based on relative economic benefit apportioned according to zonal load savings

[251] *See* id., p. 31.

[252] *See* id., p. 32.

5. Compliance with regional cost-allocation principles[253]

Principle 2: No benefit = no allocation	- Load zones not benefiting from a proposed RETP[254] will not be allocated any of the costs of the project - only where a project provides a benefit to entities and where those entities by a super majority vote to approve the project, are such project's costs allocated.
Principle 3: Benefits to Cost threshold	There is no threshold; Benefits must exceed costs (could be interpreted as 1.0 threshold)
Principle 5: Transparency	- Attachment Y provides the methodologies used to determine benefits and identify beneficiaries - all of the studies produced pursuant to the CSPP are published and available to all interested parties
Principle 6: Cost-allocation Methodologies	- See Cost Allocation Table above - Beneficiaries are identified using the present value and annual LBMP[255] load savings for all load zones which have such savings, net of reductions in transmission congestion credit payments and bilateral contracts as a result of the implementation of the project - Beneficiaries are those load zones that experience net benefits over the first ten years from the project's proposed commercial operation date.

6. Public policy requirements

NYISO address the integration of public policies into its planning and cost-allocation processes in §31.4 of its Attachment Y to the OATT. According to NYISO, each PPR planning cycle will begin following completion of the reliability planning process in each two-year reliability and economic planning cycle, and if no PPRs driving transmission needs are identified, it will be considered complete until the next two-year planning cycle, unless the New York Public Service Commission ("NYPSC") requests the NYISO conduct an analysis of transmission needs driven by such requirements in the interim.[256]

[253] *See* id., pp. 32-37.

[254] Regulated Economic Transmission Project

[255] Locational Based Marginal Pricing

[256] *See* id., p. 38.

According to NYISO, the NYPSC has the primary responsibility for the identification of transmission needs driven by PPRs. The NYPSC is also the entity that determines which proposed transmission solutions should seek the necessary local, state, and federal authorizations for construction and operation. The NYISO's role is to provide the NYPSC with the data and analyses necessary to fulfill those tasks, as well as to solicit and receive the input of its stakeholders on proposed transmission needs driven by PPRs and potential solutions to those needs.[257]

a. PPR definition

Attachment Y defines a PPR as a federal or New York State statute or regulation, including a NYPSC order adopting a rule or regulation subject to and in accordance with the State Administrative Procedure Act, or any successor statute, that drives the need for expansion or upgrades to the New York State Bulk Power Transmission Facilities.[258]

[257] *See* id., p. 39.

[258] *See* id.

b. PPR planning process[259]

Identification of transmission needs driven by PPRs to be evaluated by ISO	Requests for specific solutions to address needs driven by PPRs and evaluation	Cost Allocation Provisions
- solicitation of input - identification of PPR driving need - explanation of how solution fulfils need - consideration of NTAs - Explanation of website of which lines evaluated and why lines not evaluated.	- ISO will request and evaluate solutions driven by PPRs, identified by NYDPS.[260] - ISO will allow 60 days for submittal of solutions - ISO will identify both benefits and costs of proposed solutions, as well as market-impacts.	- based on a beneficiary pays approach - where identified PPR provides for particular cost-allocation and cost-recovery methodology, that will be used by the NYISO. - where no identified methodology, project developer may propose methodology that uses cost allocation based on load ratio share and adjusted to reflect characteristics and benefits of the specific project and the PPR that is being implemented - default proposal to allocate costs to all loads across region because public policies established by government are generally established to benefit everyone.

F. California Independent System Operator

California ISO states that its existing tariff is largely compliant with Order No. 1000 and requires only minor modifications to align completely with the detailed regional requirements enunciated in Order No. 1000 and to provide greater transparency.[261] CA ISO states that its transmission planning process governs *all* transmission upgrades to and expansions of the ISO controlled grid, and the ISO controlled grid includes all network transmission facilities – regional *and* local, high voltage *and* low voltage – that are owned by the participating transmission owners.[262] It requests therefore that FERC approve the ISO's compliance because it advances the Commission goals in Order No. 1000 effectively and is consistent with or superior to a structure that meets the Commission's minimum requirements.[263]

[259] *See* id., pp. 40-48.

[260] New York Department of Public Service

[261] *See* California Independent Transmission Operator Order 1000 Compliance Filing, Docket No. ER13-103-000, October 15, 2012, p. 15.

[262] *See* id.

[263] *See* id., p. 16.

Further, ISO considers both the local and the regional needs of load serving entities and determines the appropriate local or regional transmission facilities (or non-transmission solutions) to meet those needs, enabling the ISO to more effectively identify cost-effective regional transmission solutions that can displace local transmission facilities and plan an integrated system that will use all local and regional transmission facilities in the most efficient manner.[264]

1. Regional transmission planning requirements

a. Participation in regional planning process

According to CA ISO, it is a regional planning entity and the participating transmission owners in its footprint are participants in an Order No. 890/1000 compliant transmission planning process.[265] Further, because the ISO's existing structure and governance are consistent with the structure of a regional planning entity, reforms are not needed to satisfy this requirement of Order No. 1000.[266]

b. Regional enrollment process

A participating transmission owner signs a transmission control agreement indicated that it has turned operational control of its network transmission facilities over to the ISO.[267] If an entity that is not a participating transmission owner is assigned in the ISO's competitive solicitation process to construct and own a transmission project, it will become a participating transmission owner upon energizing the project and executing the transmission control agreement.[268] ISO's enrollment process ensures that enrolling transmission providers will be subject to the regional cost-allocation methods for the ISO region.[269]

c. Consideration of transmission needs driven by PPRs[270]

ISO's revised transmission planning process ("RTPP") includes mechanisms for consideration of PPRs in the transmission planning process and for approval of transmission facilities needed to meet such PPRs.[271]

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[264] *See* id., pp. 16-17.

[265] *See* id., p. 17.

[266] *See* id.

[267] *See* id., p. 18., fn. 22.

[268] *See* id., p. 19.

[269] *See* id.

[270] *See* id., pp. 20-22.

[271] *See* id., p. 20.

RTPP Phase 1	- first quarter of calendar year - ISO identifies, in unified planning assumptions and study plan, the state or federal requirements or directives that it will use to identify policy-driven transmission elements
RTPP Phase 2	- ISO posts conceptual statewide plan that identifies potential transmission upgrades or additional elements needed to meet state and federal policy directives and requirements - Stakeholders have the opportunity to submit comments on the conceptual statewide plan and suggest alternative solutions.
Order 1000 Enhancements	- stakeholder opportunity to submit proposals regarding state and federal policy requirements or directives for consideration in the development of the draft uniform planning assumptions and study plan - final posted Uniform Planning Assumptions and Study Plan to include explanation of the PPRs and directives that the ISO selected for consideration in the current planning cycle and the reasons that the ISO did not select other suggested needs - a PPR or directive selected for consideration in a transmission planning cycle will be carried over into subsequent transmission planning cycles unless the ISO determines that such PPR or directive has been eliminated, modified, or is otherwise not applicable or relevant for transmission planning purposes in a future transmission planning cycle

2. Cost-allocation requirements and adherence to principles

ISO's tariff allocates the cost all high voltage facilities under its operational control regionally, so by definition they are facilities "included in the transmission plan for the purpose of regional cost allocation" as described by Order No. 1000. Lower voltage lines under the ISO's operational control are equivalent to "local" transmission facilities as discussed in Order No. 1000 in that they are not subject to regional cost allocation. Instead, the existing ISO tariff allocates the costs of low voltage facilities to the applicable participating transmission owner, who recovers the costs of such low voltage facilities from its customers that the use the low voltage facilities.[272]

The ISO's cost-allocation methodology provides that all transmission facilities at voltage levels of 200 kV and above (as well as under 200 kV facilities that extend beyond the retail service territory or footprint of the applicable participating transmission owner) will be subject to competitive solicitation; transmission facilities located entirely within the retail service territory or footprint of a participating transmission owner that are below 200 kV will be constructed by such participating transmission owner.[273]

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[272] *See* id., p. 24.

[273] *See* id., p. 30.

ISO states that distinctions between the high voltage and low voltage transmission facilities that comprise the ISO-controlled grid are provided in ISO's annual transmission plans.[274] ISO also describes the different uses of various lines at both high- and low-voltage levels and suggest that the uses reveal the nature of the benefits provided by each category of transmission facility.[275] ISO states that continued use of its historic bright-line voltage level for cost-allocation purposes will provide cost certainty to customers and transmission developers, promote administrative efficiency, and reduce the burdens on the ISO and stakeholders.[276]

3. Rights of first refusal

To conform to the Order No. 1000 paradigm, the ISO proposes to create new definitions for regional and local transmission facilities based on their voltage levels and whether they are confined within the footprint of a single participating transmission owner.[277]

Local Transmission Facility	1) under the CAISO Operational Control 2) owned by a Participating TO or to which a Participating TO has an entitlement that is represented by a converted right 3) operates at a voltage below 200 kV 4) located entirely within a Participating Transmission Owner's ("PTO") footprint (if approved in or after 2013/2014 CTP)

Effectively, all regional projects are included in the transmission plan for the purpose of regional cost allocation, and all projects included in the plan for the purpose of regional cost allocation are regional projects. Local projects are included in the transmission plan, but not for the purpose of regional cost allocation.[278] Further, all regional projects that are not improvements to, additions on, or replacements of a part of an existing transmission facility are subject to the competitive process. This provision applies regardless of whether the project is needed for reliability purposes, economic reasons, to meet public policy needs, or to maintain the simultaneous feasibility of long-term congestion revenue rights ("CRRs").[279]

In asserting that its participation paradigm is superior to Order 1000's, ISO states that it proposes to limit the local transmission facilities that would be built by participating transmission owners to those with voltage levels below 200 kV. Further, the right to build a facility would not be dependent on whether the participating transmission owner decides to seek regional cost allocation for such facility. Rather, the ISO's process eliminates any discretion on

[274] *See* id., p. 26.

[275] *See* id., p. 28.

[276] *See* id., p. 30. Regarding compliance with the six Order 1000 cost-allocation principles, ISO briefly describes either how it is already compliant or why the particular principle is not applicable, and thus, compliance with these principles is not covered in this paper.

[277] *See* id., p. 34

[278] *See* id., p. 35.

[279] *See* id., p. 36.

the part of the individual transmission owner and sets forth *ex ante* which transmission facilities are eligible for regional cost allocation and which are not, thereby providing more construction opportunities for independent transmission providers than under the Order 1000.[280]

4. Project sponsor qualification and selection

Qualification Criteria[281]	(a) whether the proposed project is consistent with needed transmission elements identified in the comprehensive transmission plan; (b) whether the proposed project satisfies applicable reliability criteria and ISO planning standards; and (c) whether the project sponsor and its team are physically, technically and financially capable of (i) completing the project in a timely and competent manner, and (ii) operating and maintaining the facilities consistent with good utility practice and applicable reliability criteria for the life of the project.
Selection Criteria[282]	Comparative analysis will take into account into account all regional transmission elements for which the competing Project Sponsors have been approved or are seeking approval, the qualified Project Sponsor which is best able to design, finance, license, construct, maintain, and operate the regional transmission element(s) in a cost-effective, prudent, reliable, and capable manner over the lifetime of the transmission element(s), while maximizing overall benefits and minimizing the risk of untimely project completion, project abandonment, and future reliability, operational and other relevant problems

G. Northern Tier Transmission Group

Northern Tier Transmission Group's ("NTTG") Order 1000 compliance filing was submitted on behalf of its participating utilities that engage in a transmission planning process and participate in the Western Electric Coordinating Council ("WECC") process.[283]

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[280] *See* id., p. 38.

[281] *See* id., p. 44.

[282] *See* id., pp. 52-53.

[283] NTTG Order 1000 Compliance Filing, submitted on behalf of Deseret Generation & Transmission Co-operative, Inc. ("Deseret"), Docket No. ER13-65-000, Idaho Power Company ("Idaho Power"), Docket No. ER13-127-000, NorthWestern Corporation ("NorthWestern"), Docket No. ER13-67-000, PacifiCorp ("PacifiCorp"), Docket No. ER13-64-000, and Portland General Electric Company ("Portland General"), Docket No. ER13-68-000, October 15, 2012.

1. Regional transmission planning process enhancements

NTTG's regional transmission planning process integrates the individual, local transmission plans of each Applicant and other participating organizations into one comprehensive ten-year Regional Transmission Plan ("RTP") for the NTTG Footprint.[284] Developed on a biennial basis over eight quarters, the plan takes into account all participating TPs' current and anticipated service commitments to network, native load, and point-to-point customers. It also addresses strategic transmission options (economic and reliability projects) and alternatives for reinforcing the transmission system, as well as integration of new generation, reducing congestion, and non-transmission alternatives.

Through the biennial planning process, NTTG's RTP compiles needs and then indentifies least cost expansion project alternatives, technical benefits, projected costs, and an allocation of costs. NTTG's regional transmission planning process also allows stakeholders to submit requests for economic studies and includes a four-step dispute resolution procedure.[285]

NTTG members have made several modifications to their regional transmission process to address the requirements and clarifications provided in Order No. 1000.[286]

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[284] *See* id., p. 11.

[285] *See* id.

[286] NTTG provides a detailed description of its regional transmission planning process in the Regional Planning and Cost Allocation Practice document, available at: http://nttg.biz/site/index.php?option=com_docman&task=doc_download&gid=1871&Itemid=31

Submission of Data[287]	(a) load and resource data; (b) forecasted transmission service requirements; (c) whether the proposed project meets reliability or load service needs; (d) economic considerations; (e) whether proposed project satisfies transmission need driven by PPRs; (f) project location; (g) voltage level; (h) structure type; (i) conductor type and configuration; (j) project terminal facilities; (k) project costs, associated annual revenue requirements, underlying assumptions and parameters in developing revenue requirements; (l) project development schedule; (m) current project development phase; and (n) in-service date.
Consideration of PPRs[288]	- Applicant obligated to collect customer data, including transmission needs driven by PPRs, as part of local planning process - Applicant provides NTTG with local transmission plan, which includes transmission service forecasts reflective of PPRs and public policy projects, and transmission needs driven by PPRs and Public Policy Considerations for consideration in regional planning process - Quarter 2: the NTTG Planning Committee will review and winnow the transmission needs and associated facilities driven by PPRs and Considerations received in Quarter 1 using criteria established in the Practice Document - Planning Committee will prepare explanation for why certain transmission needs driven by PPRs and Considerations were or were not selected and post the information on its website.
Alternative Solutions[289]	- Quarter 1: any stakeholder may submit alternative solutions to meet the identified needs - Quarters 3 and 4: NTTG conducts modeling of the system loads, resources and improvements to evaluate preliminary feasibility, reliability and efficiency of the system and any alternatives - Quarter 5: any stakeholder may submit comments or additional information about new or changed circumstances related to alternative transmission solutions - Quarter 6: Biennial Study Plan will be revised to reflect any new or changed circumstances related to alternative solutions

[287] The reforms require the project sponsor (*i.e.*, TP, non-incumbent transmission developer, merchant transmission developer, or any other stakeholder) of a transmission project proposed for inclusion in the RTP to submit certain minimum information for the purpose of providing basic modeling data for NTTG's power system planning models. *See* id., pp. 12-13.

[288] *See* id., p. 14. This takes place during Quarter 1 of the Biennial Planning Process. Also, in Quarter 1, any stakeholder may submit data to be evaluated as part of the preparation of the RTP, including transmission needs and associated facilities driven by PPRs and Public Policy Considerations. *See* id.

[289] *See* id., pp. 15-16. NTTG will conduct its regional planning process using identified regional transmission service needs, transmission, and NTAs to define benefits and projected costs that meet the regional transmission needs more cost effectively and efficiently than the combined local transmission system plans. *See* id.

Explanation of Methodology, Criteria and Processes[290]	- Quarter 2: Development of Biennial Study Plan will describe methodology, criteria, assumptions, databases, projects subject to reevaluation, analysis tools, and public policy projects used/analyzed during preparation of RTP - Planning Committee will present the Biennial Study Plan for comment by stakeholders and Planning Committee members at a publically held Planning Committee meeting - Planning Committee will update the Biennial Study Plan, based upon stakeholder comments, information about new or changed circumstances
Reevaluation[291]	- submission of project development schedule - establishment of date certain for rights-of-way and construction permits - submission of milestone progress report - inform planning committee of any delays - remove/replace project based upon conditions[292]

2. Regional cost allocation

According to NTTG, to date, its members have relied upon participant funding to fund regional transmission projects.[293] While still permitted, NTTG members reformed their tariffs to comply with Order 1000's prohibition against using participant funding as the regional cost-allocation method. NTTG proposed to meet the Order 1000 cost-allocation principles in the following manner:

[290] *See* id., pp. 16-17.

[291] *See* id., pp. 17-19.

[292] (a) the developer of the project fails to meet its project development schedule such that the needs of the region will not be met, (b) the developer of the project fails to meet its project development schedule due to delays of governmental permitting agencies such that the needs of the region will not be met, or (c) the needs of the region change such that a project with an alternative location and/or configuration meets the needs of the region more efficiently and/or cost effectively. *See* id., p. 19.

[293] *See* id., p. 20.

Principle 1: Beneficiaries[294]	Three benefit metrics designed to quantify the benefits. First metric captures benefits related to both reliability and Public Policy Requirements. The second/third metrics capture benefits related to economic projects.[295]
Principle 2: No benefit = no allocation	- Cost Allocation Committee initially identifies beneficiaries as all those entities that may be affected by the proposed project - Adjustment criteria prevent allocation if average of the adjusted net benefits across all allocation scenarios is negative. - Beneficiaries who may see wide variations across multiple allocation scenarios are assigned zero benefits and are not allocated any project costs[296]
Principle 3: Threshold	- No threshold - Project must have an estimated cost which exceeds the lesser of $100 million or 5% of the project sponsor's net plant in service. - Project must have total estimated benefits to regional entities, other than the project sponsor, that exceed $10 million. - Ratio of adjusted net benefits to allocated costs is no less than 1.10

H. Public Service Company of Colorado[297]

Public Service Company of Colorado ("PSCo") states that all ten of the pre-Order No. 1000 WestConnect members that are publicly-owned (non-jurisdictional) transmission owners participated with the seven FERC-jurisdictional pre-Order No. 1000 WestConnect transmission

[294] NTTG developed three benefits metrics:

1. Change in annual capital-related costs. This metric captures the financial and economic impact of deferring or replacing a transmission project in the initial Regional Transmission Plan as a result of another transmission project or non-transmission alternative.
2. Change in energy losses. This metric captures the change in energy generated to serve a given amount of load.
3. Change in reserves. This metric is based on savings that may result when two or more balancing areas could economically share a reserve resource when unused transmission capacity remains in a proposed transmission project. *See* id., p. 24. Adjustment criteria are also applied to initial benefits determinations before costs are allocated. *See* id., p. 29.

[295] *See* id., p. 28.

[296] *See* id., p. 29.

[297] Public Service Company of Colorado ("PSCo") is a member of WestConnect and participated in WestConnect's Order 1000 compliance planning processes. While the filing provides insights into the WestConnect process, the compliance filing was made on behalf of Xcel Energy Affiliates PSCo and Southwestern Public Service Company ("SPS").

owners, along with an active group of stakeholders, to negotiate the Order No. 1000 regional transmission planning and cost-allocation processes described in their filing.[298]

1. Regional planning process and planning principles

The purpose of the proposed WestConnect transmission planning process is to identify regional needs and to determine the more efficient or cost effective solutions for those regional needs.[299]

- WestConnect will use WECC-approved regional system base cases as a reference point to begin the regional power flow and economic analyses and will run a number of base cases using power flow, production cost modeling, and other modeling qualifiers.[300]

- WestConnect will validate the model through a regional reliability assessment to make sure all inputs are included (included PPRs) and data assumptions are consistent.[301]

- The Planning Management Committee ("PMC") will vote to approve the Regional Plan and will explain why certain projects were or were not included in the plan.[302]

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[298] *See* Order 1000 Compliance Filing of PSCo, Docket No. ER13-75-000, October 15, 2012. The non-FERC jurisdictional TOs participating in the WestConnect Order 1000 planning process includes: Basin Electric Power Cooperative, Colorado Springs Utilities, Imperial Irrigation District, Platte River Power Authority, Sacramento Municipal Power District, Salt River Project, Southwest Transmission Cooperative, Transmission Agency of Northern California, Tri-State Generation and Transmission Cooperative, and Western Area Power Administration. The FERC-jurisdictional participants include: Black Hills Power, Inc., Black Hills Colorado Electric Utility Company, LP, and Cheyenne Light, Fuel, & Power Company are one entity (Black Hills Corporation); Nevada Power Company and Sierra Pacific Power Company are one entity (NV Energy, Inc.); and Tucson Electric Power Company and UNS Electric, Inc. are one entity (UNS Energy Corp.) *See* id., fn. 20 and 21.

[299] *See* id., 9.

[300] *See* id.

[301] *See* id. Further studies will be performed and NTAs will be considered. *See* id.

[302] *See* id. Significant project delays or changes will trigger a reevaluation. *See* id., p. 10.

Coordination[303]	- with WECC and its planning sub-groups with respect to data - among stakeholders who must study proposed projects and NTAs, and make selections on eligibility
Openness	- studies of potential upgrades or grid investments - offering alternative transmission solutions to meet identified grid needs - offering public policy input - offering NTAs - sponsoring a transmission project for evaluation in the planning process, - commenting on the plan
Transparency	- any person or company desiring membership on the PMC must identify itself - public posting of the individual steps in the study process, deadlines for action required at each step - interested stakeholders can gain access to study data, subject to confidentiality, CEII, and Standards of Conduct

2. Public policy considerations

During the initial phases of each regional transmission planning cycle, the PMC will review enacted PPRs and determine which transmission needs will be included in the modeling for that cycle.[304] Transmission needs driven by PPRs will be identified by the individual transmission owners within the WestConnect planning region through their respective local planning processes and needs, and any projects necessary to satisfy them, will be submitted to WestConnect in accordance with the regional planning process for inclusion in the Regional Plan.[305] All stakeholders will have an opportunity to participate in PPR and project evaluation and WestConnect will post on its website explanations of which PPR-driven needs were evaluated and why others were not.[306]

3. Cost allocation

According to PSCo, projects will be evaluated for cost allocation consideration and deemed eligible for cost allocation if they address a reliability, economic, or public policy objective in the WestConnect Order No. 1000 planning region, and all eligible projects will be evaluated on comparable basis and in a manner that is not unduly nondiscriminatory or preferential.[307]

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[303] *See* id., pp. 10-13.

[304] *See* id., p. 14.

[305] *See* id.

[306] *See* id.

[307] *See* id., p. 16.

Facility Type	Definition	Cost Allocation
Reliability Projects	Necessary to address a regional Transmission Planning ("TPL") Reliability Standard developed by NERC and approved by the Commission as mandatory and enforceable	must meet an identified NERC TPL Reliability Standard need identified within the region through the regional planning process during the ten-year planning period.
Economic Projects	Associated with congestion relief which provide for more economic operation of the regional transmission system	demonstrate that it provides for more economic operation of the system in a manner that satisfies the required benefit-to-cost ratio for various evaluated scenarios: 1.25
Public Policy Projects	- Proposed to address a transmission need driven by PPR - Not addressed in WestConnect transmission owners' local transmission planning process	- Demonstrated to satisfy a PPR not proposed through a transmission owners' local planning process. - Costs shared among the entities that will access the resources enabled by the project to meet their PPRs.

In addition, the WestConnect Order No. 1000 cost-allocation methodology also considers that a proposed project may address a combination of reliability, economic, and/or public policy objectives.[308] In such cases, the WestConnect planning process, in conjunction with stakeholders, will determine what types of benefits to consider when assessing the benefit-to-cost ratio for a particular project. Finally, facilities that span multiple service geographic territories or footprints, but only provide service to a single entity's electrical distribution service territory or footprint will be considered single system transmission projects ineligible for regional cost allocation (unless they benefit other systems).[309]

I. Florida Power & Light Company

According to Florida Power & Light ("FPL"), its local transmission planning process works in conjunction with, and is an integral part of, the Florida Reliability Coordinating Counsel's ("FRCC") regional transmission planning process which facilitates coordinated planning by all transmission providers, owners and stakeholders within the FRCC Region.[310] FPL states that FRCC transmission planning process already provides many of the features identified in Order No. 1000, such as the development of a regional transmission plan.[311]

[308] *See* id., p. 17. In such cases, the WestConnect planning process, in conjunction with stakeholders, will determine what types of benefits to consider when assessing the benefit-to-cost ratio for a particular project.

[309] *See* id., pp. 17-18.

[310] *See* FP&L Order 1000 Compliance Filing, Docket No. ER13-104-000, October 15, 2012, p. 3. This filing, while on behalf of FPL, offers discussion of the "Florida Sponsors'" compliance filing, including FPL, JEA, Orlando Utilities Commission, Progress Energy Florida, and Tampa Electric Company.

[311] *See* id., p. 4.

1. Regional planning process

The FRCC process begins with the consolidation of the long term transmission plans of all of the transmission owners/providers in the FRCC Region. Detailed evaluation and analysis of these plans is conducted by the Transmission Working Group/Stability Working Group, in concert with the FRCC staff, and managed by the Planning Committee. Such evaluation and analysis provides the basis for possible recommended changes to individual system plans that, if implemented, would result in a more reliable and robust transmission system for the FRCC Region.[312]

As an initial matter, FPL points out that the FRCC Region has vertically integrated utilities that utilize integrated resource planning ("IRP") processes which Order No. 1000 respects, and which are used to determine the resources required to meet reliability, economic and public policy needs, including transmission resources. [313]

According to FPL, the Florida Sponsors believe it is appropriate to continue the long-standing approach of beginning the development of the regional transmission plan with a roll-up of the individual utility local transmission plans, which reflects the "bottom-up" regional planning approach that is permitted in Order Nos. 1000 and 1000-A.[314]

Projects that would be subject to regional cost allocation are Cost Effective and/or Efficient Regional Transmission Solution ("CEERTS") projects which would also be open to both incumbent and non-incumbent transmission developers to construct and operate.[315]

2. Regional project upgrades and ROFR

According to FPL's reading of Order 1000, a project eligible for development by a non-incumbent developer must:

1) be a project selected in a regional transmission planning process for purposes of cost allocation because it is a more efficient or cost-effective solution to a regional transmission need;
2) must not be an upgrade to another entity's transmission facilities; and
3) must not be a local transmission facility.[316]

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[312] Id.

[313] *See* id., p. 7. FPL also notes that the Florida Public Service Commission ("FPSC") has broad authority over transmission planning

[314] *See* id., p. 9. The rollup is of "local" transmission projects that are not subject to regional cost allocation. *See* id.

[315] *See* id., p. 12.

[316] *See* id., p. 15.

3. CEERTS projects

According to FPL, in the IRP process, the integrated utility's optimum approach to serving its load is determined by, among others, market conditions, operating costs, operating characteristics, public policy requirements, and proprietary inputs such as fuel costs, and heat rates.[317] FPL further states that there is no valid formula-type methodology for economic projects on a regional basis because the FRCC Region does not have a centralized energy market based on security constrained economic dispatch.[318]

4. Avoided transmission cost allocation methodology and cost allocation principles

The Florida Sponsors proposes an avoided transmission cost methodology in which avoided transmission costs are the costs of projects in the regional transmission plan that would otherwise have been constructed in the absence of an approved CEERTS project.[319]

Principle 1: Beneficiaries	costs of CEERTS projects are allocated to beneficiaries -- those transmission providers that do not have to incur capital costs for the avoided projects.
Principle 2: No benefit = no allocation	transmission providers who are avoiding costs are agreeing through their OATT filings to be allocated costs on the basis of the costs being avoided.
Principle 3: Benefit/Cost Threshold	benefit to cost threshold for projects passing through an initial screen is set at anything greater than 1.0

5. Public policy considerations

To be considered in transmission planning, a PPR must be reflected in state, federal, or local law or regulation (including an order of a state, federal, or local agency).[320] The PPR must drive a transmission need that is not readily met through existing, approved requests for new transmission service and/or already planned transmission facilities.[321] Potential public policy transmission needs shall be submitted to the FRCC, whose planning committee, under the

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[317] *See* id., p. 16.

[318] *See* id. FPL states further that using production cost simulations to quantify benefits carries the *invalid premise* that the region is centrally dispatched on a production cost basis, and that if transmission projects were based on production cost simulations that assume centralized dispatch, transmission would be built that would not provide the simulated benefit. *See* id.

[319] *See* id., p. 17. The avoided transmission cost of each Transmission Provider that is provided by the CEERTS project is the benefit to that Transmission Provider. The avoided transmission cost of each Transmission Provider divided by total avoided transmission costs is multiplied by the CEERTS project cost to determine the CEERTS project cost allocated to each Transmission Provider. *See* id.

[320] *See* FPL Order 1000 Compliance Filing, Proposed §11.1, (p. 84 of PDF).

[321] Id.

oversight of the FRCC Board, will evaluate those submittals and make a decision as to whether a PPR is driving a transmission need that is not otherwise readily, cost-effectively, and efficiently met through existing requests for new transmission service and/or already planned transmission facilities, and will post this determination on the FRCC website, along with an explanation of that determination.[322] If a public policy transmission need is identified, CEERTS and local projects may be proposed to address such a need.[323]

[322] Id

[323] Id.

6. Compliance with Order 890 planning principles

Coordination[324]	- consults directly with customers seeking transmission/generator interconnection service - topics such as load growth projections, planned generation resource additions/deletions, new delivery points and possible transmission alternatives are discussed. - transmission customers/users also have an additional opportunity to raise any issues, concerns or minority opinions that they believe have not been adequately addressed
Openness	- meetings are held on a regular basis to discuss loads, generation/network resource additions/deletions, new facility additions and upgrades, demand resource information, customer's projections of future needs, and related subjects that have an impact on the provision of transmission service to a customer. - any interested entity or person may participate in FRCC committees through participation in a sector and entities may raise concerns that they believe were not adequately addressed at the local level.[325]
Transparency[326]	- FPL makes available Facility Connection Requirements, Capacity Benefit Margin ("CBM") Methodology and other pertinent information used in the transmission planning process and posts this information on its OASIS website. - FPL provides written descriptions of the basic methodology, criteria and processes used to develop its plans. - transmission planning criteria are available to all customers and stakeholders and transmission planning assumptions, transmission projects/upgrades and project descriptions, scheduled in-service dates for transmission projects and the project status of upgrades will be available to all customers through the FRCC periodic project update process. - CEERTS project sponsor and other stakeholders in the FRCC Region are provided with information related to the CEERTS project and the details of the evaluation process. Meetings are held and reports are made to keep all parties informed concerning project evaluation.

[324] *See* id., pp. 23-24.

[325] *See* id., pp. 24-25. The Planning Committee consists of six stakeholder sectors: Suppliers, Non-Investor Owned Utility Wholesalers, Load Serving Entities, Generating Load Serving Entities, Investor Owned Utilities, and General.

[326] *See* id., pp. 26-28.

Information Exchange[327]	- FPL exchanges the initial transmission plan and data with a transmission customer to provide an opportunity for the transmission customer to evaluate the initial study findings or to propose potential alternative transmission solutions for consideration. - FPL makes available to a transmission service customer the underlying data, assumptions, criteria and transmission plans utilized in the study process. - If information is deemed confidential, FPL requires the customer to enter into a confidentiality agreement prior to providing the confidential information.
Comparability[328]	FPL incorporates into its transmission plans both retail and wholesale firm transmission obligations: - retail obligations consist of load growth, interconnection and integration of new network resources, firm power purchases and new distribution substations. - wholesale obligations are existing firm wholesale power sales, existing long-term firm transmission service including firm point-to-point and network, projected network load, generator interconnections, and new delivery points. - Both FPL and the transmission customers reflect their demand response resources in their load forecast projections which are input within the planning process.
Economic Planning Studies[329]	- FRCC Regional Transmission Planning Process includes both economic and congestion studies - Sensitivities may include: evaluating the FRCC Region with various generation dispatches that test or stress the transmission system; and combination/cluster of generation and load serving capability involving various transmission providers in the FRCC experiences significant and recurring transmission congestion on their transmission facilities.

[327] *See* id., p. 29.

[328] *See* id., pp. 29-30.

[329] *See* id., p. 31.

V. A Discussion of Impacts on States

This section identifies and briefly discusses three Order 1000 compliance provisions that may impact state electric regulatory authorities in a manner that suggests closer state electric regulatory authority attention throughout the ongoing compliance process.

First, the Order 1000 planning provision that requires each TP to coordinate with its stakeholders to identify PPRs that are appropriate to include in its local and regional transmission planning processes[330] invites state regulatory authorities to input state jurisdictional public policy goals into regional transmission planning processes, potentially providing an avenue to states to help effectuate their legislative mandates and greatly influence which transmission lines are financed and ultimately constructed.

Second, the first Order 1000 regional cost-allocation principle, which states that the cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits,[331] was later clarified to include that in order for a cost-allocation method to be accepted as compliant, a TP will have to *clearly and definitively specify the benefits and the class of beneficiaries*.[332] The specific identification within regions of benefits and beneficiaries will have significant consequences on costs allocated transmission rate payers and may similarly influence which transmission lines are financed and ultimately constructed.

Third, the Order 1000-A provision stating that before considering a proposed compliance provision removing a federal ROFR, the Commission must first determine whether the agreement is protected by a *Mobile-Sierra* provision, and if so, whether the Commission has met the applicable standard of review such that it can require the modification of the particular provisions,[333] will likely impact the level of regional competitiveness for transmission solutions and determine the number of potential solutions that can be considered.

Out of the host of Order 1000 Rulings provisions described in the proceeding sections, we identify these three provisions as being of particular interest to state regulatory authorities due to their cost, jurisdictional and policy-effectuating consequences. A brief discussion of each follows.

A. State determinations of transmission needs driven by public policy requirements

FERC strongly encourages states to participate actively in the identification of transmission needs driven by PPRs.[334] While rejecting a proposal to establish a particular status

[330] *See* Order 1000, ¶167 (*see also* fn. 36, infra).

[331] *See* Order 1000, ¶622.

[332] *See* Order 1000-A, ¶678 (*see also* fn. 76, supra) (emphasis added).

[333] *See* Order 1000-A, ¶ 398 (*see also* fn. 57, supra).

[334] *See* Order 1000, ¶209.

for state regulators in the transmission planning process,[335] FERC suggests options to ensure that stakeholder input feeds into the PPR-identification process.[336] Further, FERC notes that Order 1000 does not alter the role of states in transmission planning, but rather complements state efforts by helping to ensure that potential solutions to identified transmission needs driven by PPRs of the states can be evaluated in local and regional transmission planning processes.[337] According to FERC, state regulators should play a strong role to ensure that their respective transmission planning process are consistent with state requirements, particularly in the case of PPRs, where state regulators are likely to have unique insights as to how transmission needs driven by state-level PPRs should be satisfied.[338]

This invitation for strong participation in the transmission planning process with respect to transmission needs driven by PPRs offers an opportunity to have a broad array of state policy goals considered in TP planning processes. One expert suggests that Order 1000 provides a way for FERC and the states to combine their different and somewhat complementary authorities to serve their common goals: identifying and providing that mix of resources that serves consumers most cost-effectively, with due protection of the environment, and reliably, using a mix of regulation and markets.[339] Further, the requirements placed upon TPs to participate in regional planning processes and consider PPRs invites states to create a state-level resource plan and direct the state's utilities to integrate the state resource plan into the regional transmission plan.[340]

Consideration of PPRs regionally will present state regulators with a host of resource-choice, cost and reliability-based decisions. Renewable energy policies may require consideration of additional transmission lines that connect to remote areas, while energy efficiency and demand response goals could reduce or negate the need for new or enhanced transmission in certain regions.[341] Regardless of which PPRs are considered in transmission

[335] The Commission stated that it will not require a particular status for state regulators in the transmission planning process**,** because to do so would ignore the wide range of roles that state regulators are permitted to take under their various state laws. *See* id., ¶337.

[336] *See* Order 1000, fn. 189. For example, FERC states that some TPs could rely on committees of state regulators or, with appropriate approval from Congress, compacts between interested states to identify transmission needs driven by PPRs for the TPs to evaluate in the transmission planning process.

[337] *See* id., ¶¶ 212, 213. FERC requires that TPs respect states "concerns" when considering transmission needs driven by PPRs. *See* id.

[338] *See* Order 1000-A, ¶338.

[339] *See* Hempling, Scott, *How Order 1000's Regional Transmission Planning Can Accommodate State Policies and Planning*, ElectricityPolicy.com, September 2012, p. 2. (available at http://bit/ly/PqNKkw.)

[340] *See* id., p. 5.

[341] *See* Gerrard, Michael B. and Welton, Shelley, *FERC Order 1000 as a New Tool for Promoting Energy Efficiency and Demand Response*, Center for Climate Change Law, Columbia Law School (Working Paper to be published November 2012). A broad array of federal and state laws can be identified as PPRs such as the *Energy Policy and Conservation Act of 1975*, 42 U.S.C. §6321(3)

planning processes, it is clear that their consideration can have immense impacts on *when, where or whether* significant transmission infrastructures expenditures are made.[342]

B. The regional determination of beneficiary

As noted in Section II of this paper, Cost-allocation principle 1 requires the cost of transmission facilities to be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.[343] FERC left the determination of benefits to be addressed by the TPs and their stakeholders in the development of the cost-allocation methods for their regions, but stated that in order to be deemed compliant the TP must clearly and definitively specify the benefits and the class of beneficiaries.[344] FERC added,

> ….while Order No. 1000 does not define benefits and beneficiaries, it does require the public utility transmission providers in each region to be definite about benefits and beneficiaries for purposes of their cost allocation methods. Once beneficiaries are identified, public utility transmission providers would then be able to identify what is the more efficient or cost effective transmission solution or assess whether costs are being allocated at least roughly commensurate with benefits.[345]

Cost causation requires that FERC-approved tariffs ensure that the customers creating the need for new transmission pay increased rates equivalent to the cost of the upgrades they have necessitated.[346] Under the beneficiary-pays principle, to justify socialized cost allocation to

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(2012) which promoted EE, the *Energy Independence and Security Act of 2007*, PL 110-40, 121 STAT. 1492, which sets new lighting standards and building efficiency standards, and the *American Recovery and Reinvestment Act of 2009*, Pub L. No. 111-5, 123 Stat. 138 which invested billions into home weatherization. *See* id., fn. 21-24. In addition, twenty-four states have adopted energy efficiency resources standards ("EERS"). *See* id., p. 8.

[342] *See, for example, New England 2030 Power System Study*, (ISO New England, February 2010,) which compared a variety of on-shore and off-shore wind energy transmission scenarios ranging in costs from $6 billion to over $25 billion on behalf of the New England Governors, p. 21. As an additional example, see Virginia State Corporation Commission Case No. PUE-2009-00043, Order Granting Withdrawal (January 2010) in which the Potomac-Appalachian Transmission Highline (PATH project) was withdrawn, in part, due to modeling which included impacts of demand response resources.

[343] *See* fn. 72, supra.

[344] *See* Order 1000-A, ¶¶676, 678.

[345] *See* id., ¶679. FERC also noted that cost causation is the foundation of an acceptable cost allocation method. *See* Order 1000, ¶626.

[346] *See* Maser, Gabe, *It's Electric, but FERC's Cost-Causation Boogie-Woogie Fails to Justify Socialized Costs for Renewable Transmission*, Georgetown Law Journal, Vol 100, 1834. (citing to *KN Energy, Inc v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

ratepayers for transmission facilities, FERC must outline the system-wide benefits the new transmission facility provides with "reasonable particularity."[347]

The identification and definition of beneficiaries has historically posed challenges to state regulators and transmission planning process stakeholders and the addition of the PPR layer to the analysis promises to add further complexity. For example, a transmission project that links a state with large amounts of wind to a state with a high RPS requirement might benefit the origin state with economic development benefits and the receiving state with a lower RPS compliance option, but may provide few benefits to an intermediate state that the transmission line passes through.[348]

Each PPR identified will pose its own unique benefits-defining challenges. For example, an analysis of access to renewable resources could be complicated by the inclusion of externalities such as impacts on view corridors, endangered species, critical habitat, human health and water use.[349] In considering total or net tons of green house gas ("GHG") reductions due to a transmission option, any net benefit calculation will need to be based on consistent valuation assumptions to be meaningful.[350] Such consistency will also be required when considering additional PPRs such as lower air emissions, public health benefits or economic development (green jobs).[351]

C. The *Mobile-Sierra* doctrine and the ROFR[352]

The Commission determined that if a regional transmission planning process does not consider and evaluate transmission projects proposed by non-incumbents, that regional transmission planning process cannot meet the Order No. 890 transmission planning principle of being "open," and stated in addition, that such a regional planning process may not result in a cost-effective solution to regional transmission needs, resulting in higher cost than necessary.[353]

[347] *See* id., p. 1835. The author notes that while courts have analyzed cost-allocation methodologies for reliability projects under cost causation, as yet methodologies for economic and renewable transmission have not been scrutinized under this principle. *See* id.

[348] *See FERC Order 1000 & Public Policy Transmission Projects*, a papery by NERA Economic Consulting, March 5, 2012, p. 4.

[349] *See* id., p. 6.

[350] *See* id. Also, in defining benefits, one state may have a history of incorporating reductions in GHG emissions as a benefit in its analysis of the economics of alternative expansion plans, while another state may have a history of excluding those emissions reductions. *See* id., p. 4.

[351] *See* id., pp. 6-7.

[352] This section discusses the potential impacts of the Commission's decision on the *Mobile-Sierra* and ROFR matter to state regulatory authorities. For a discussion of the *Mobile-Sierra* Doctrine and the Public Interest Standard, please see Appendix C.

[353] *See* Order 1000, ¶¶228-229 (referring to Notice of Request for Comments; Transmission Planning Processes under Order No. 890; Docket No. AD09-8-000, October 8, 2009). The Commission explained that, where an incumbent transmission owner has a federal ROFR, a non-incumbent transmission developer risks losing its investment to develop a transmission project that it

Stating that the existence of federal ROFRs may be leading to rates that are unjust and unreasonable, the Commission determined that allowing federal ROFRs to remain in Commission-jurisdictional tariffs and agreements would undermine the consideration of potential transmission solutions proposed at the regional level.[354]

The manner in which regions consider alternative transmission solutions could impact the consequences of removing federal ROFRs. The evaluation of alternative transmission solutions at the regional level is often referred to as "top down" planning which receives heavy emphasis in some regions.[355] In other regions, local transmission plans are developed in which individual TPs identify solutions to their own local needs prior to the "top down" consideration of regional alternatives—often referred to as "bottom up, top down" planning.[356] The fundamental nature of "bottom-up, top-down" transmission planning is where local needs and solutions are combined within a region and analyzed to determine whether regional solutions would be more efficient or cost-effective than the local solutions identified by individual public utility transmission providers.[357]

The Commission noted that allowing entities, such as non-public-utility transmission developers, the opportunity to potentially propose a transmission project as a non-incumbent transmission developer furthers the Commission's goal in Order No. 1000 of ensuring that all transmission developers have a comparable opportunity to incumbent transmission developers/providers to propose a transmission project for selection in the regional transmission plan for purposes of cost allocation.[358]

As discussed in Section II above, FERC modified the RFOR requirement stating that a TP who considers its contract to be protected by a *Mobile-Sierra* provision may present its arguments as part of its compliance filing; that any such compliance filing must include the revisions to any Commission-jurisdictional tariffs and agreements necessary to comply with Order No. 1000 as well as the *Mobile-Sierra* provision arguments; and that the Commission will first decide whether the agreement is protected by a *Mobile-Sierra* provision, and if so, whether the Commission has met the applicable standard of review such that it can require the modification of the particular provisions.[359]

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proposed in the regional transmission planning process, even if the transmission project that the non-incumbent transmission developer proposed is in a regional transmission plan. *See* id., ¶230.

[354] *See* id., ¶256. ROFRs create barriers to entry that discourages non-incumbent transmission developers from proposing alternative solutions for consideration at the regional level. *See* id., ¶257.

[355] *See* Order 1000, ¶255

[356] *See* id.

[357] *See* id., ¶258.

[358] *See* Order 1000-A, ¶417.

[359] *See* id., ¶389. As such, the Commission is not requiring TPs to eliminate a federal ROFR before the Commission makes a determination regarding whether an agreement is protected by a *Mobile-Sierra* provision and whether the Commission has met the applicable standard of review.

Therefore, FERC has created a compliance filing threshold matter wherein, if a TP asserts that the *Mobile-Sierra* doctrine protects a contract or set of contracts regarding TP rights, then in order to consider removal of a federal ROFR, the Commission must first determine: (1) the contract(s) at issue is not a *Mobile-Sierra* contract, or (2) the contract(s) at issue is a *Mobile-Sierra* contract, and the public interest standard of review has been met.[360]

As Order 1000 does not affect state or local laws or regulations regarding the construction of transmission facilities including permitting or siting, states seem positioned to either bolster state ROFR requirements or prohibit them depending on the reliability, economic or public policy impacts of either decision. Certain states may codify a ROFR into state law to ensure that incumbent TPs retain exclusive rights to build.[361] On the other hand, if a state believes that elimination of the ROFR will facilitate price-reducing competition and grid expansion[362] (as FERC suggests will be the case), then it could prohibit incumbents from receiving state-based ROFRs and subject transmission developers to a competitive solicitation model as envisioned in Order 1000.[363] Careful consideration, cost/benefit analyses and the ability to adapt to a changing regulatory framework will help guide state decision-making in these respects.

D. Conclusion

The Order 1000 Rulings fundamentally alter the way in which system planning will occur. This paper summarizes the Order 1000 rulings, discusses legal concerns underlying the Order 1000 Rulings and responses that may be taken up in the federal appellate courts, provides an overview of certain compliance filing tariff provisions, and identifies three particular provisions that may be of ongoing interest to state regulatory commissioners and staff in terms of their ratepayer cost and state policy-effectuating consequences. Though initial compliance filings have been made, protests, answers and interim FERC Orders may alter initial tariff provisions, and it behooves state regulatory authorities to monitor the evolving processes in their regions.

This paper recommends that state regulators pay particular attention to 1) the procedures adopted to consider PPRs and to identify benefits and classes of beneficiaries for purposes of cost allocation, and 2) FERC's determination of whether TP Agreements are protected under the *Mobile-Sierra* doctrine. A subsequent paper could comment on the April 2013 interregional planning and cost-allocation compliance filing provisions and select a different sample of regions for examination.

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[360] A number of TPs have made this claim. *See*, *for example*, SPP Order 1000 Compliance Filing, p. 50; MISO Order 1000 Compliance Filing, p. 39.

[361] *See Gone with the Wind: What will Replace the Right of First Refusal?*, a presentation by ITC Holdings Corp. to the Harvard Electricity Policy Group, Sixty-Sixth Plenary Session, March 8-9, 2012, p. 9, 15.

[362] *See* id., pp. 12, 14.

[363] To the extent a region already has in place processes to rely on market proposals or *competitive solicitations* when identifying solutions to the region's needs, such existing processes may require relatively modest modifications to provide non-incumbent transmission providers with the opportunity to propose and construct transmission projects. *See* Order 1000, ¶259 (emphasis added).

Appendix A: Table of Abbreviations

BRP	Baseline Reliability Project (MISO)
CARIS	Congestion Analysis and Resource Integration Study (New York ISO)
CEERTS	Cost Effective and/or Efficient Regional Transmission Solution (FPL)
CEII	Critical Energy Infrastructure Information
CRP	Comprehensive Reliability Plan (New York ISO)
CRR	Congestion Revenue Rights
CSPP	Comprehensive System Planning Process (New York ISO)
CTOA	Consolidated Transmission Owners Agreement
DC	Direct Current
DFAX	Distribution Factor
DPP	Detailed Project Proposal (SPP)
DR or DRRs	Demand Response of Demand Response Resources
FCM	Forward Capacity Market (ISO New England)
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
FRCC	Florida Reliability Coordinating Counsel
GHG	Greenhouse Gas
IEP	Industry Expert Panel (SPP)
IRP	Integrated Resource Planning
ISAC	Independent State Agency Committee (PJM)
ISO	Independent System Operator
ITP	Integrated Transmission Planning (SPP)
LBMP	Locational Based Marginal Pricing (New York ISO)
LCR	Locational Capacity Requirements
LOLE	Loss of Load Expectation
LSP	Local System Plan (ISO New England)
LTPP	Local Transmission Planning Process (New York ISO)
MAPP	Mid-Atlantic Power Pathway
MEP	Market Efficiency Project (MISO)
MISO	Midwest Independent System Operator
MTEP	Midwest Transmission Expansion Plan
MTF/MTO	Merchant Transmission Facility (ISO New England)
MVP	Multi-Value Project (MISO)
NESCOE	New England States Committee on Electricity
NTA	Non-Transmission Alternative
NYDPS	New York Department of Public Service
NYPSC	New York Public Service Commission
OA	Operating Agreement
OATT	Open Access Transmission Tariff
OMS	Organization of MISO States
OTF/OTO	Other Transmission Facility/Other Transmission Owner (ISO New England)

PAC	Planning Advisory Committee (ISO New England)
PATH	Potomac-Appalachian Transmission Highline
PMC	Planning Management Committee (PSCo)
PPR	Public Policy Requirement
PPTU	Public Policy Transmission Upgrades (ISO New England)
PSCo	Public Service Company of Colorado
PTF/PTO	Pool Transmission Facility/Owner (ISO New England)
QRP	Qualified RFP Participant (SPP)
QTPS	Qualified Transmission Project Sponsor (ISO New England)
RETP	Regulated Economic Transmission Project (New York ISO)
RFP	Request for Proposal
RNA	Reliability Needs Assessment (New York ISO)
ROFR	Right of First Refusal
RPP	Reliability Planning Process (New York ISO)
RSP	Regional System Plan (ISO New England)
RTEP	Regional Transmission Expansion Plan (PJM)
RTO	Regional Transmission Organization
RTP	Regional Transmission Plan (NTTG)
RTPP	Revised Transmission Planning Process (California ISO)
SPS	Southwest Public Service Company
STEP	SPP Transmission Expansion Plan
TOA	Transmission Owners Agreement (ISO New England)
TP	Transmission Provider
WECC	Western Electricity Coordinating Council

Appendix B: A Note on Order 1000-B and the ROFR

In Order 1000-B, the Commission responded to requests for further clarification on two fronts concerning removal of the federal ROFR:

1. first, parties requested clarification on Order No. 1000-A's determination that if *any* of the costs of a new transmission facility are allocated regionally or outside of a TP's retail distribution service territory, then there can be no federal ROFR associated with the facility;[364]

2. second, certain parties raised the concern that projects with costs allocated to a single zone should be considered local, even if there is more than one TP located in that zone, so that the TP may retain a federal ROFR under those circumstances.[365]

In response to the first concern, the Commission stated *in general*, if *any* costs of a new transmission facility are allocated regionally or outside a single transmission provider's retail distribution service territory, *that is an application of the regional cost-allocation method* and that new transmission facility is not a local transmission facility.[366] The Commission had already determined that any regional cost allocation of the cost of a new transmission facility outside a single transmission provider's retail distribution service territory or footprint, *including an allocation to a "zone" consisting of more than one TP*, is an application of the regional cost-allocation method and that new transmission facility is *not* a local transmission facility.[367]

In response to the second concern, the Commission stated that special consideration is needed when a small transmission provider is located within the footprint of another transmission provider,[368] but that many of the arguments related to multi-transmission provider zones were premature because the Commission did not adopt a generic rule as to whether a cost allocation solely to a multi-transmission provider zone is an application of the regional cost-allocation method for which a federal ROFR must be eliminated.[369]

Commissioner LeFleur indicated in a dissenting opinion that rather than reach a definitive conclusion with respect to whether *any* amount of regional funding converts an otherwise local

[364] *See* Order 1000-B, ¶51 (emphasis added).

[365] *See* id.

[366] *See* id., ¶52 (emphasis added). Therefore, once a new transmission facility is selected in the regional transmission plan for purposes of cost allocation, it is no longer a local transmission facility exempt from the requirements of Order Nos. 1000 and 1000-A regarding the removal of federal ROFR.

[367] *See* id., ¶42 (emphasis added).

[368] *See* Order 1000, ¶424.

[369] *See* Order 1000-B, ¶54. Further, the Commission stated that petitioners have not presented evidence that would support the Commission making a generic finding or providing additional guidance for all multi-transmission provider zones in this rulemaking proceeding.

reliability project into a regional project requiring removal of the ROFR, where such complex questions are presented, the Commission should decide the issue on compliance, with a record. According to Commissioner LeFleur, doing otherwise is premature, denies transmission-planning regions the flexibility to define local projects, and establishes categorical rules that could undermine the planning and cost-allocation goals Order No. 1000 intended to achieve.[370]

[370] *See* id., Order 1000-B, Commissioner LeFleur Dissent.

Appendix C: The *Mobile-Sierra* Doctrine and the Public Interest Standard

In 1956, the U.S. Supreme Court issued a series of Orders holding that a party who has entered into a FERC-jurisdictional contract cannot request that the FERC change the contract unless the contract itself authorizes the party to seek the change.[371] The Court reasoned,

> Our conclusion that the Natural Gas Act does not empower natural gas companies unilaterally to change their contracts fully promotes the purposes of the Act. By preserving the integrity of contracts, it permits the stability of supply arrangements which all agree is essential to the health of the natural gas industry.[372]

A party seeking to change the terms of a contract may argue that adherence to the terms would violate the public interest. In applying the public interest exception, the Court stated,

> The sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest – as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory.[373]

The Court subsequently held that the *Mobile-Sierra* doctrine applies to market-based contracts stating that the mere fact that the market is imperfect, or even chaotic, is no reason to undermine the stabilizing force of contracts that the FPA embraced as an alternative to purely tariff-based regulation.[374] The Court elaborated that "the regulatory system…is premised on

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[371] *See United Gas Pipeline Co. v. Mobile Gas Service Corp.*, 350 U.S. 332, 343-44 (1956); *Federal Power Commission v. Sierra Pacific Power Company*, 350 U.S. 348, 352-55 (1956). *See also* Hempling, Scott, *Electricity Law: Current Topics 2009*, National Regulatory Research Institute, Little Rock, AR, June 18-19, 2009, p. WC-55.

[372] *See Mobile*, 350 U.S. at 344. *See also* Hempling, *Electricity Law*, *supra*, p. WC-55.

[373] *Sierra Pacific Power*, 350 U.S. at 354. *See also* Hempling, *Electricity Law, supra,* p. WC-56. The Court reaffirmed this concept stating that "when a seller utility unilaterally seeks an increase from a fixed-rate contract already on file with the Commission – the public interest (as opposed to the private interest of the party seeking the rate increase) only rarely is served by making the requested change (that is, granting the requested increase), and a strict standard is appropriate." *Northwest Utilities Service Company (Re: Public Service of New Hampshire)*, 66 F.E.R.C. ¶61,332 (1994). *See also* Hempling, *Electricity Law*, *supra*, p. WC-56.

[374] *See Verizon Communications v. Federal Communications Commission,* 535 U.S. 467 (2002), at 479. *See also* Hempling, *Electricity Law*, p. WC-67. The "purpose of the *Mobile-Sierra* doctrine is to preserve the benefits of the parties' bargain as reflected in the contract." *Atlantic City Electric Co. v. FERC*, 295, F. 3d 1, 14 (D.C. Cir. 2002) (citing *Town of Norwood v. FERC*, 587, F.2d 1306, 1312 (D.C. Cir. 1978)).

contractual agreements voluntarily devised by the regulated companies; it contemplates abrogation of these agreements only in circumstances of unequivocal public necessity."[375]

As noted in Section V of this paper, and given legal framework described above, in order to consider proposed compliance provisions removing a federal ROFR, the Commission must first determine: (1) the contract(s) at issue is not a *Mobile-Sierra* contract, or (2) the contract(s) at issue is a *Mobile-Sierra* contract, and the public interest standard of review has been met.

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[375] *Morgan Stanley Capital Group, Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 562 fn. 2 (quoting *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968).

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