UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities	**)** **)** **)** **)**	**Docket No. RM10-23-000**

COMMENTS OF COLUMBIAGRID

On June 17, 2010, the Federal Energy Regulatory Commission ("FERC" or "Commission") issued a Notice of Proposed Rulemaking on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities ("NOPR").[1] ColumbiaGrid hereby submits its comments in response to the NOPR.[2]

I. INTRODUCTION AND SUMMARY

ColumbiaGrid is a non-profit membership, Washington State corporation that was formed on March 31, 2006. It is intended to facilitate regional transmission planning among its members. The current members of ColumbiaGrid are Avista Corporation ("Avista"); Bonneville Power Administration ("Bonneville"); Public Utility District No. 1 of Chelan County, Washington; Public Utility District No. 1 of Snohomish County, Washington; Public Utility District No. 2 of Grant County, Washington; Puget Sound Energy, Inc. ("PSE"); City of Tacoma, Department of Public Utilities, Light Division (dba Tacoma Power); and The City of Seattle, by and through its City Light Department.

ColumbiaGrid's geographic area of interest covers the entire Pacific Northwest sub-region of the Western Electricity Coordinating Council ("WECC"). That area consists of Washington, Oregon, Idaho, the part of Montana in the Western Interconnection, Utah,

[1] 131 FERC ¶ 61,253 (2010).

[2] Individual ColumbiaGrid PEFA parties and WECC may submit other comments.

Wyoming, Nevada, British Columbia, Alberta, and those parts of Bonneville's statutory service area not included in the foregoing area. ColumbiaGrid's members are among the signatories to the ColumbiaGrid Planning and Expansion Functional Agreement ("PEFA"), which provides for sub-regional transmission planning among the signatories. The PEFA was filed at the Commission on behalf of ColumbiaGrid's jurisdictional members – Avista and PSE – and accepted by the Commission on April 3, 2007.[3] Although not members of ColumbiaGrid, Public Utility District No. 1 of Cowlitz County and Public Utility District No. 1 of Douglas County participate in the collective sub-regional transmission planning process of ColumbiaGrid as signatories to the PEFA. Thus, ColumbiaGrid participants encompass a range of participants, from public utilities to non-public utilities.[4]

Avista and PSE incorporated the ColumbiaGrid planning process as part of their Attachment K compliance filings to Order No. 890; these compliance filings were made to demonstrate their participation in transmission planning processes that satisfied the planning principles of Order No. 890.[5] In addition, Bonneville submitted a petition for declaratory order that its Attachment K satisfied reciprocity standards and also incorporated the ColumbiaGrid planning process that set forth their local and regional transmission planning processes.

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3 *ColumbiaGrid*, 119 FERC ¶ 61,007 (2007).

4 Each of the following five Washington State municipal corporations and public utility districts is pleased to be contributing to Northwest regional transmission planning and development through membership in ColumbiaGrid: the Public Utility District No. 1 of Chelan County, Washington; the Public Utility District No. 2 of Grant County, Washington; the City of Seattle, a municipal corporation of the State of Washington, acting by and through its City Light Department; the Public Utility District No. 1 of Snohomish County, Washington; and the City of Tacoma, Department of Public Utilities, Light Division, d/b/a Tacoma Power. Each of these governmental utilities anticipates continuing its voluntary ColumbiaGrid membership into the future. Further exposition of their common position on the question of Commission legal authority may be found in the comments of the Large Public Power Council, in which four of these five governmental utilities are members.

5 *See Preventing Undue Discrimination and Undue Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

In the WECC region, ColumbiaGrid closely coordinates with neighboring planning entities in the Western Interconnection through its active, ongoing participation in the WECC subregional and regional processes. ColumbiaGrid is a sub-regional planning group ("SPG") in the Western Interconnection and coordinates as such with other SPGs and WECC. The SPG process involves regular joint SPG meetings, which are held at least three times yearly and are focused on reviewing and coordinating study activities, development of WECC base case assumptions and requests, sharing of planning information, and coordination of requests to WECC for economic studies.[6]

These comments may be summarized as follows:

- The diverse mix of jurisdictional and non-jurisdictional entities in the ColumbiaGrid region necessitates a collaborative approach to planning.
- The NOPR's proposed reforms could threaten the continued viability of ColumbiaGrid's successful collaborative approach to planning.
- Regional transmission planning in the Northwest is robust and the Commission should permit the planning processes to continue to evolve.
- A transmission plan in a non-Regional Transmission Organization ("RTO") region provides information used in developing construction plans and allocating costs but does not and cannot impose project construction or cost-reimbursement obligations.
    - Planning processes in non-RTO areas, like the ColumbiaGrid planning process, typically do not grant rights to construct projects.
    - Certain aspects of the proposed reforms could threaten the collaborative approach of the PEFA. In particular, the Commission should not impose planning requirements for non-RTO areas that create rights to project ownership or construction or create obligations to pay project costs.
    - The "non-incumbent" reforms should not be extended to transmission owners that are not participants in RTOs.

[6] The regional transmission planning approach in the West is succinctly summarized in the WECC TEPPC 2009 Annual Report, Executive Summary at p. 8 (Apr. 6, 2010): "Transmission planning in the Western Interconnection is done using a layered structure. Transmission providers do local planning and SPGs bring groups together to plan for subregions within WECC."

- Application of the non-incumbent reforms to transmission owners that are not participants in RTOs is not supported by the record.

- The Commission has not demonstrated authority to require its proposed non-incumbent reforms.

- A formalized structure of interregional coordination is unnecessary and should not be imposed.

- The NOPR's cost allocation proposals exceed the Commission's authority and are unnecessary and burdensome.

  - The Commission must balance the evidence and need for the reforms against the burdens created by the reforms.

  - There is no reason to require modifications to the ColumbiaGrid cost allocation methodologies.

  - The Commission should recognize that a cost allocation methodology is not a rate and that a cost allocation methodology does not recover costs on its own.

  - The Commission's cost allocation proposals are an unexplained departure from prior precedent and beyond its Federal Power Act authority.

  - The Commission should clarify certain OATT reforms. A public utility transmission provider should not and cannot be expected to unilaterally bind other transmission providers -- jurisdictional and non-jurisdictional -- to follow any particular method for cost allocation.

- The proposed reforms exceed the Commission's authority under section 202 of the Federal Power Act.

II. GENERAL COMMENTS

A. The Diverse Mix of Jurisdictional and Non-Jurisdictional Entities in the ColumbiaGrid Region Necessitates a Collaborative Approach to Planning.

Prior to the notice of proposed rulemaking that would evolve into Order No. 890,[7] the first steps toward the ColumbiaGrid transmission planning process were taken in early 2006, with ColumbiaGrid's incorporation following in March 2006 and ColumbiaGrid's first board of directors elected in August 2006. Since that time, the ColumbiaGrid planning process has grown

[7] *See Preventing Undue Discrimination and Undue Preference in Transmission Service*, Notice of Proposed Rulemaking, 115 FERC ¶ 61,211 (2006).

and successfully incorporated a wide range of entities into its planning process. ColumbiaGrid participants include two investor-owned utilities; five public utility districts of Washington; two municipal utilities; and Bonneville, a federal power marketing agency that controls seventy-five percent of the high voltage transmission facilities within the ColumbiaGrid area. Obtaining the active participation of all of these players was a key prerequisite to developing a meaningful transmission planning structure in this area of the Northwest. Indeed, the existing ColumbiaGrid structure and planning approach were essential to bringing this range of entities into its process.

Generally, ColumbiaGrid's transmission planning process is designed to facilitate a "single-utility" approach to transmission planning among its members, under which the transmission facilities of various transmission providers are planned as if owned by a single utility. In addition to developing a transmission plan for parties to the PEFA that own or operate transmission facilities ("Transmission Owner or Operator Planning Party" or "TOPP"),[8] ColumbiaGrid annually performs a system assessment of the interconnected transmission systems in the Pacific Northwest that is focused on determining the ability of each TOPP to serve, consistent with the appropriate reliability standards and criteria, both its network and native load obligations and other existing long-term firm transmission obligations anticipated to arise over the ten-year planning horizon. The fundamental principles of the PEFA are ones of cooperation and collaboration, from the study process to addressing cost allocation.

As it is in many of the regions, cost allocation was a difficult issue in the formative stages of ColumbiaGrid. Many entities, such as the municipal entities that participate in ColumbiaGrid, must consider legal restrictions under their charters or state laws that curtail their flexibility to agree to various types of cost allocations in advance of a project's completion. Therefore, the

[8] *See* PEFA § 1.57.

"cost allocation principle" for projects in a planning process in the ColumbiaGrid region necessarily had to be one that permitted some degree of flexibility, but that also reflected basic cost causation principles and the principles of collaboration and cooperation.

B. Regional Transmission Planning in the Northwest Is Robust And The Commission Should Permit The Planning Processes To Continue To Evolve.

The ColumbiaGrid planning process has helped to create significant coordination in planning among transmission systems in the Northwest. To date, the ColumbiaGrid planning process has developed and adopted several transmission plans that affect multiple systems. The latest update to the ColumbiaGrid plan reported on the various stages of development of more than thirty contemplated projects.[9]

As part of the subregional planning process, ColumbiaGrid has formed study teams including non-PEFA parties that develop focused transmission plans to address complex transmission issues in specific areas such as the Puget Sound area in Northwest Washington and the Northern Mid-Columbia area in Central Washington. In particular, during 2009, the Puget Sound Area Study Team reviewed the seasonal operating limit studies of the British Columbia to Northwest path and examined the effect of several potential projects on transfer capability in the long term. The Northern Middle Columbia Area Study Team is developing a one-utility plan to address system deficiencies in the greater Wenatchee area. The Cross Cascades Study Team was launched to address possible reliability concerns of the Cross Cascades transmission paths that deliver resources from east of the Cascade Mountains of Oregon and Washington to the west side load areas.

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[9] *See* 2010 Update to 2009 Biennial Transmission Expansion Plan (Feb. 17, 2010), available at: http://www.columbiagrid.org/planning-expansion-overview.cfm.

ColumbiaGrid is also considering the issue of how to facilitate further development of renewable resources. In particular, ColumbiaGrid and the Northern Tier Transmission Group have formed the Wind Integration Study Team to facilitate the integration of renewable generation into the Northwest transmission grid. The current focus of the group is to support the technical study needs of existing sub-regional and regional initiatives by addressing the increased use of dynamic scheduling and addressing action items from the Northwest Wind Integration Action Plan.[10]

In another initiative, ColumbiaGrid is currently evaluating, and has discussed with a number of stakeholders, the feasibility of applying the open season concept as a means of responding to transmission service requests across multiple systems in an efficient and coordinated manner and developing a plan of service that would meet the needs of the committed customers of all the transmission providers. The ColumbiaGrid Board of Directors passed a resolution on September 10, 2009, directing ColumbiaGrid to facilitate a process to scope a multi-party open season. The ColumbiaGrid PEFA Parties, together with interested non-PEFA transmission providers and stakeholders, commenced this scoping process on November 16, 2009, to evaluate the potential for a multi-party open season on the transmission systems of PEFA Parties and participating non-PEFA transmission providers. The scoping exercise involves, among other things, identifying the possible structure for such an open season (including guiding principles, participants, roles and responsibilities), feasibility assessment, estimated costs, and anticipated benefits. These efforts are ongoing. Any final decision on

[10] The Wind Integration Action Plan identified issues that need to be resolved for wind power to achieve its full potential in the Northwest. The Action Plan is available on the Northwest Power and Conservation Council's website: http://www.nwcouncil.org/energy/wind/library/2007-1.htm.

whether to go forward with such an open season will ultimately depend on the agreement of the applicable systems.

As an SPG, ColumbiaGrid also participates in larger-scale regional transmission planning. WECC coordinates regional transmission planning in the Western interconnection, using the transmission plans developed by the SPGs.[11] The SPGs were organized to address common issues within a particular portion of the Western Interconnection on a more localized level, as they are closer to the loads being served and more accessible to smaller load serving organizations such as municipal utilities and rural electric cooperatives.[12]

The WECC regional transmission planning process is currently taking on further planning activities pursuant to funding provided by the American Recovery and Reinvestment Act of 2009 ("ARRA"). WECC has been awarded $14.5 million in funding from the ARRA to conduct interconnection-wide electric transmission planning studies in the Western Interconnection through a process that is known as the Regional Transmission Expansion Process ("RTEP").

In short, it is too early to make a reasoned assessment of the regional planning processes so soon after Order No. 890 because new regional planning processes may not have completed multiple planning cycles and are continuing to evolve and be fine-tuned along the way; for its part, ColumbiaGrid has completed its first planning cycle. In light of the success of the transmission planning process in the ColumbiaGrid region and WECC-wide, ColumbiaGrid

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[11] WECC recognizes seven SPGs: ColumbiaGrid, Northern Tier Transmission Group, the California Independent System Operator, Colorado Coordinated Planning Group, Sierra Subregional Planning Group, Southwest Area Transmission Group, and Alberta Electric System Operator.

[12] *See* WECC TEPPC 2009 Annual Report, Executive Summary at p. 14 (Apr. 6, 2010), available at: http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/TEPPC%20Annual%20Reports/2009/2009%20TEPPC%20Annual%20Report.pdf

submits that the Commission should not implement the proposed reforms at this time but rather should permit the planning processes to evolve.

C. The NOPR's Proposed Reforms Could Threaten the Continued Viability of ColumbiaGrid's Successful Collaborative Approach to Planning.

The Commission's proposed reforms appear to require many of the hallmarks of an RTO planning process (*e.g.*, by proposing cost allocation requirements and the allocation of ownership and construction rights), but large parts of the Western Interconnection, including the area for which ColumbiaGrid plans, are not RTOs and do not have the underlying structures in place that would permit adoption of the reforms. In addition, it would be extremely expensive and time-consuming for non-RTO transmission owners to attempt to comply with the Commission's reforms.

Indeed, adoption of the Commission's proposed reforms could threaten the viability of planning processes conducted by ColumbiaGrid and groups like it. The ColumbiaGrid collaborative planning approach is incompatible with such RTO structures, and it is unclear at this stage that ColumbiaGrid would retain the active cooperation of all of its participants if an attempt is made to impose such RTO structures. Although the ColumbiaGrid members view the planning process as working very well at this time, certain ColumbiaGrid members have indicated they are considering withdrawing from ColumbiaGrid if the NOPR requirements are adopted and made applicable to ColumbiaGrid. The Commission should avoid imposing changes in planning processes that diminish the important planning processes already in place and should avoid imposing changes that drive parties away from participating in those processes.

III. COMMENTS ON SPECIFIC PROPOSED REFORMS

A. A Transmission Plan in a Non-RTO Region Provides Information Used in Developing Construction Plans and Allocating Costs But Does Not and Cannot Impose Project Construction or Cost-Reimbursement Obligations.

ColumbiaGrid requests that the Commission confirm in the final rule that there is no obligation to build or binding cost allocation arising out of a plan in a non-RTO-region. ColumbiaGrid intends to continue to use its multi-system process for subregional transmission planning within the Northwest. However, as discussed below, the NOPR proposes to impose requirements for non-RTO areas that are properly imposed only on RTO areas, ColumbiaGrid is not an RTO, and ColumbiaGrid is not in a position to impose binding obligations on its members or other PEFA parties to develop the projects identified in its biannual transmission plan or to pay costs allocated under such plan. (As discussed below, the formation of RTOs has not been mandated by the Commission.) Inclusion of projects in the ColumbiaGrid plan should not be misconstrued as a requirement that they must be built or as creating an obligation to pay project costs.

B. Non-Incumbent Project Sponsor Participation

1. Planning Processes In Non-RTO Areas, Like The ColumbiaGrid Planning Process, Typically Do Not Grant Rights To Construct Projects.

In the NOPR, the Commission states its concern that a non-incumbent transmission developer risks losing its proposed project, even if that proposal is selected for inclusion in the regional transmission plan, if an incumbent transmission owner decides to build the project.[13] To address its concerns, the Commission proposes a number of reforms to the planning process that will, in the Commission's view, "level the playing field."

[13] *See* NOPR at P 87.

The NOPR fails to recognize that the planning processes in non-RTO areas, like the ColumbiaGrid planning process, typically do not grant rights to construct projects. Further, participation in the ColumbiaGrid planning process is already on a level playing field through its Study Team approach and is open to non-incumbent project sponsor participation. In fact, in response to the Commission's orders discussing the ColumbiaGrid regional transmission planning process, ColumbiaGrid specifically amended the PEFA to permit entities, not presently transmission owners, to propose both transmission and non-transmission projects as alternatives to any proposal being studied by a Study Team.[14] Moreover, party status under the PEFA is open to any "Qualified Person," defined under the PEFA to include "any Person that operates or *proposes to operate* an Electric System in the Pacific Northwest."[15]

2. Certain Aspects of the Proposed Reforms Could Threaten the Collaborative Approach of the PEFA. In Particular, the Commission Should Not Impose Planning Requirements for Non-RTO Areas That Create Rights to Project Ownership or Construction or Create Obligations to Pay Project Costs.

As a general principle, ColumbiaGrid agrees with the Commission that openness and opportunities for non-incumbents to participate in a regional transmission planning process are important, and these are, in fact, key elements of the ColumbiaGrid planning process. Nevertheless, ColumbiaGrid is troubled by the implication of the NOPR's proposed findings, *i.e.*, that an existing planning process may be presumed to be unjust and unreasonable or unduly discriminatory if the process does not already facilitate non-incumbent participation in the manner proposed by the Commission. ColumbiaGrid is also concerned that several of the

[14] Section 4.1.1 of Appendix A of the PEFA, in relevant part, states: "As part of the Study Team process, any Study Team participant may propose a transmission or non-transmission alternative to the Project being developed by such Study Team and shall provide information regarding the proposed alternative to assist in the evaluation of such proposed alternative under the criteria in Section 2."

[15] *See* PEFA § 1.46 (emphasis added).

specific "non-incumbent" reforms could threaten the collaborative approach to transmission planning that is so important to ColumbiaGrid participants.

The Commission's proposed reforms could be interpreted as requiring more than what the PEFA currently addresses to the extent they would require establishing new rights to construct and own transmission facilities.[16] The PEFA does not bestow any rights or obligations of ownership or construction on any of its parties. Although there is considerable ambiguity in the NOPR's proposed requirements, the Commission should not create through planning requirements for non-RTO areas any rights to project ownership or construction—for incumbents or non-incumbents—or obligations to pay project costs. A transmission plan in a non-RTO region provides information used in developing construction plans and allocating costs but does not and cannot impose project construction or cost-reimbursement obligations. For example, the Commission should recognize that creating for non-RTO areas a non-incumbent "right" that forecloses a transmission owner's pursuit of ownership or construction of a project that is needed may result in the preclusion of timely construction of needed projects. The Commission should ensure that the ability to construct and operate needed projects – including reliability projects –in a timely fashion will not be impeded, even if a non-incumbent sponsor fails in its attempts to build a project. Further, the Commission should avoid transmission planning requirements, such as creation of an exclusive right to construct and own for a non-incumbent, that would restrict the ability of an affected transmission owner to participate in a State siting process for the non-incumbent's project.

[16] *See* NOPR at P 93.

In addition, strict requirements for the development of forms for project sponsors to complete,[17] of deadlines for submission of proposed projects,[18] and of evaluation criteria for "selecting" projects[19] may threaten the collaborative approach embodied by the Study Team process of ColumbiaGrid. The PEFA does not include a strict, typical open season process, although any interested person may join a Study Team and propose an alternative project. The PEFA contemplates that projects may evolve over time, and possibly become Expanded Scope Projects, and the Commission should not impose planning requirements that would frustrate such evolution.

The NOPR's proposed requirements to have a deadline for the submission of projects, with an accompanying mechanism to distinguish among similar projects, raise further questions that must be answered.[20] For example, it is unclear whether such a requirement would apply both to regional planning and single system planning. It is also unclear whether such a requirement would apply to facilities that are planned to be built in response to transmission service requests and interconnection requests. In particular, for those transmission service and interconnection requests for which it is determined that facilities must be added, it is unclear whether the planning for such facilities is to be treated as "proposals to be considered in a given transmission planning cycle."[21] If so, the Commission should clearly indicate this and recognize that the time periods specified in the OATT for processing responses to requests for transmission service and interconnection must be revised in order to be consistent with such treatment.

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17 *See id.*

18 *See id.*

19 *See id.* at P 92.

20 *See id.* at P 91 and 94.

21 *See id.* at P 91.

As ColumbiaGrid reads the NOPR, the Commission seems to be concerned about the possibility that non-incumbents may be treated unfairly. In addressing that concern, however, the Commission should not create some preferred status for non-incumbents. In any event, ColumbiaGrid believes that it treats non-incumbents fairly and that the Commission has not shown that planning requirements must be revised in non-RTO areas.

3. The "Non-Incumbent" Reforms Should Not Be Extended To Transmission Owners That Are Not Participants in RTOs.

Many of the proposed reforms addressing obstacles to non-incumbent transmission sponsor participation seem to presuppose an open season approach or an RTO regional planning process, where an independent entity is given the right to pick "winners" and "losers" in awarding rights to construct and own transmission facilities. For example, the NOPR would require a mechanism to identify similar proposed projects and modifications,[22] mandate the creation of priority rights to develop a project that is resubmitted in the planning process after initially not being included in a plan,[23] and establish a rule that a sponsor of a project "selected" through a transmission planning process has a right to construct and own the facility.[24]

Although these may be appropriate measures to apply to an RTO, where the transmission owners have entered into an agreement transferring control of transmission facilities to the RTO, and where transmission owners have voluntarily agreed that the RTO may determine which projects may be built and which transmission owners have an obligation to build, this is not the case in other regions such as the ColumbiaGrid region. Indeed, in order to comply with the proposed rules, the NOPR appears to contemplate that jurisdictional non-RTO transmission

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22 *See id*. at P 94.

23 *See id*. at P 95.

24 *See id*. at P 93.

owners must create some arrangement that mimics the elements of an RTO. The Commission has consistently maintained that the decision to form an RTO was, and is, a completely voluntary one[25] and, moreover, one it would not attempt to mandate generically.[26] Thus, the Commission should clarify that its proposed reforms regarding jurisdictional non-incumbent transmission sponsors are not applicable to transmission providers that are not participants in an RTO.

4. Application of the Non-Incumbent Reforms To Transmission Owners That Are Not Participants in RTOs Is Not Supported By The Record.

The Commission makes a proposed preliminary finding that a planning process that does not consider and evaluate projects proposed by non-incumbents may result in projects being developed at a higher cost than necessary, with the result that regional transmission services would be provided at rates, terms and conditions that are not just and reasonable.[27] The proposed finding is unclear in its focus on "regional transmission services," an undefined term in the NOPR. The Commission should clarify that this proposed requirement is inapplicable to transmission providers that do not offer service over their facilities under a regional transmission services tariff.

To the extent, however, that the Commission's finding would mean that, when considered together, the rates under multiple transmission providers' OATTs for a wheeling transaction across their transmission systems must be considered unjust and unreasonable because a non-incumbent transmission sponsor did not have an explicit, standing right extended by the local utilities to construct and own transmission facilities, it would be lacking any

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25 *See Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,034 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607, 614-616 (D.C. Cir. 2001).

26 *See* Order No. 2000-A at 31,360.

27 *See* NOPR at P 88.

foundation. There are no facts in the record to support the conclusion that the identity of the sponsor of a transmission facility has a significant relationship to the ultimate cost of the facility, and furthermore, to the future rates that would be proposed for the facility. Moreover, there is no rational basis for also concluding that non-incumbent sponsors could develop cheaper transmission facilities than could incumbent transmission owners.

ColumbiaGrid welcomes the participation of non-incumbent transmission owners in its planning processes and has designed its processes consistent with Commission guidance to facilitate such participation. As a general matter, however, ColumbiaGrid disagrees with the proposition that any different treatment in a planning process among transmission owners and non-incumbent transmission sponsors rises to the level of or constitutes undue discrimination.[28] Discrimination is "undue" when there is a difference in rates or services among similarly situated customers that is not justified by some legitimate factor.[29] "If customers have different rights or abilities, they are not similarly situated."[30] There are significant legal differences between transmission owners and non-incumbent transmission sponsors under state laws that make them not "similarly situated," and thus, there would be no undue discrimination.[31] Non-incumbent transmission sponsors that do not presently own or operate transmission facilities would not be public or non-public utilities or have a state obligation to build their electric systems to meet the needs of their native load. They also would have no existing eminent domain authority granted by a state.

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28 *See* NOPR at P 87, 89.

29 *See City of Anaheim, et al*., 113 FERC ¶ 61,091 at P 130 n.179.

30 *See id*.

31 *See Southwestern Electric Cooperative, Inc. v. FERC*, 347 F.3d 975, 981 (D.C. Cir. 2003))

It appears that the only situation offered by the Commission where undue discrimination may exist is where there is a contractual provision in an agreement that grants a right of first refusal to transmission owner members of RTOs.[32] If, in a non-RTO context, the transmission provider's OATT or agreements do not create a "right" to construct or own new transmission projects, the Commission's preliminary findings in the NOPR should be inapplicable. There is no such right for incumbent transmission providers in ColumbiaGrid. There is no support in the NOPR for the finding that where there is no contractual provision creating a right of first refusal (which would deny a nonincumbent transmission developer the right to develop a transmission project), or where transmission owners do not participate in an RTO transmission planning process, there are risks of undue discrimination against non-incumbent transmission sponsors. As a result, the additional proposed reforms -- which would require public utility transmission providers that are not in RTOs to undertake the costly and burdensome process of developing appropriate construction and ownership rights for non-incumbents in their planning processes -- are not supported. To the extent that the Commission would rely on the possibility or theoretical threat of undue discrimination to support applying such reforms to non-RTO transmission owners, the Commission should first explain why a Section 206 complaint would not be sufficient to address the problem and how a theoretical possibility of undue discrimination justifies such costly reforms.[33]

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[32] *See* NOPR at P 87 ("We are concerned that it may be unduly discriminatory or preferential to deny a nonincubment transmission developer that sponsors a project that is included in a regional transmission plan the rights of an incumbent transmission provider *that are created by a transmission provider's OATT or agreements subject to the Commission jurisdiction*.") (emphasis added).

[33] *See National Fuel Gas Supply Corp. v FERC*, 468 F.3d 831, 844 (D.C. Cir. 2006).

5. The Commission Has Not Demonstrated Authority To Require Its Proposed Non-Incumbent Reforms.

The potential scope of the aspects of the NOPR relating to nonincumbents is troubling and the Commission should not adopt them and apply them industry-wide, unless the Commission clarifies its authority to do so. ColumbiaGrid notes that the Commission has limited authority under FPA Section 203 regarding the ownership of transmission facilities,[34] and limited authority under FPA Section 216 over the siting and construction of new transmission facilities.[35] These authorities are not implicated in this proceeding.

The decision to invest in or construct a facility has been viewed in the past as committed to the discretion typically reserved to public or non-public utilities to make business and investment decisions.[36] There is no authority for the proposition that the Commission could, through a Section 206 proceeding, require a public or non-public utility to acquire ownership or divest itself of transmission facilities or to construct new transmission facilities (except as required to grant or maintain service). Furthermore, as a creature of statute, the Commission cannot do indirectly that which it cannot do directly.[37] Thus, it is unclear how, on a generic basis under Section 206 in this proceeding, the Commission could propose to require public and non-public utilities to adopt enforceable rules that attempt to mandate such outcomes.

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34 16 U.S.C. § 824b.

35 16 U.S.C. § 824p.

36 In the context of state regulatory authority over public utilities, the Supreme Court has explained that: "It must never be forgotten that, while the state may regulate with a view to enforcing reasonable rates and charges, it is not the owner of the property of public utility companies, and it is not clothed with the general power of management incident to ownership." *See State of Missouri v. Southwestern Bell Telephone Co*., 262 U.S. 276, 289 (1923). The Supreme Court added that "[t]he commission is not the financial manager of the corporation, and it is not empowered to substitute its judgment for that of the directors of the corporation. . ." *See id*. Although this discussion was in the context of a state regulatory commission's authority, the D.C. Circuit has also confirmed that the Commission's jurisdiction over transmission and rates does not extend to the public utility's basic managerial decisions. *See California Independent System Operator Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004) (finding that FERC could not regulate the composition of the board of the California Independent System Operator).

37 *See e.g*., *Bonneville Power Admin. v. FERC*, 422 F.3d 908, 914, 924 (9th Cir. 2005).

C. A Formalized Structure of Interregional Coordination Is Unnecessary and Should Not Be Imposed.

The Commission proposes to require each public utility transmission provider through its regional transmission planning process to coordinate with the public utility transmission providers in each of its transmission planning regions within its interconnection to address transmission planning issues.[38] The Commission proposes that such coordination must be embodied in an interregional transmission planning agreement filed with the Commission.[39]

ColumbiaGrid believes that, in substance, its process already complies with this requirement through its participation in WECC as an SPG. Given the highly coordinated planning that takes place in the West through the WECC process, the Commission's proposed reforms are unnecessary. ColumbiaGrid also submits that it is unnecessary to formalize this structure through an agreement to be filed with the Commission. Indeed, transmission providers in the WECC interconnection arguably should only have to reflect in their Attachment Ks the SPG and WECC processes and details regarding their existing relationship, as Avista and PSE have already done. It should be unnecessary to divert resources to developing a series of formal agreements to be filed with the Commission.

D. The NOPR's Cost Allocation Proposals Exceed the Commission's Authority and Are Unnecessary and Burdensome.

ColumbiaGrid believes that the cost allocation proposals exceed the Commission's authority, and that the Commission has not described the basis for its authority to impose such proposals. More fundamentally, ColumbiaGrid does not believe that it should be necessary for public utility transmission providers to develop fixed methodologies for allocating the costs of new intra- and interregional transmission facilities.

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38 *See* NOPR at P 114.

39 *See id.*

1. The Commission Must Balance The Evidence And Need For The Reforms Against The Burdens Created By The Reforms.

The NOPR's justification for cost allocation reforms does not include requisite specific evidence and appears to be based largely on the comments of others and theory, making it difficult to assess the true nature and extent of the issues. Because the Commission relies on theoretical evidence to support its NOPR reforms, it must follow the guidance of *National Fuel Gas Supply Corp. v. FERC*, where the D.C. Circuit explained the basic findings that the Commission must make in order to support burdensome rules based only on theoretical evidence.[40] In particular, the D.C. Circuit explained that, to support a rule based only on theoretical evidence, the Commission would have to make findings on, among other things: (i) whether the magnitude of any potential danger sought to be remedied by the proposed rules is sufficient to justify the costly reforms; and (ii) why the individual complaint procedure would not address the abuse.[41]

There is no evidence in the NOPR concerning the "magnitude" of the harms the Commission hopes to address. For example, one basis for the cost allocation reforms is the purported "free rider" problem (*i.e.*, customers who do not agree to support a particular project may nonetheless receive substantial benefits from it).[42] There is no evidence in the NOPR of this "free rider" problem and it appears to be only speculation. Furthermore, the "free rider" theory ignores the significant costs incurred by utilities in constructing transmission systems, and the costs being incurred by utilities to develop the regional planning processes.

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[40] 468 F.3d 831 (2006).

[41] *See id.* at 844.

[42] *See* NOPR at P 124, 142; Order No. 890 at P 561.

The Commission also suggests that its cost allocation reforms are needed because "a lack of rate structures creates significant risk for developers of new transmission."[43] (As a preliminary matter and as discussed below, it is not clear that the NOPR provides a "rate structure" under the Federal Power Act for the collection of transmission project costs.) There is no evidence of such risk (or its magnitude) set forth in the NOPR. Indeed, many regions recently have adopted cost allocation methodologies pursuant to Order No. 890 to provide up-front certainty and there is no evidence that such methodologies do not work. With respect to the ColumbiaGrid region, ColumbiaGrid already has cost allocation methodologies in place for Requested Service Projects, Existing Obligation Projects, and Capacity Increase Projects that provide up-front clarity to transmission sponsors, both incumbent and non-incumbent. ColumbiaGrid members believe this process works well. While there are always risks with new transmission development, the risk clearly is not so great in the ColumbiaGrid region as to discourage transmission investment -- as noted earlier, more than thirty transmission projects are in various stages of development through the ColumbiaGrid planning process. This activity in transmission development indicates that the Commission is incorrect that a lack of further cost allocation mechanisms is an impediment to new transmission development.[44]

The proposed reforms will be burdensome on transmission owners. In ColumbiaGrid's view, the proposed rules regarding cost allocation and interregional planning agreements are inconsistent with their stated objectives because the proposed rules will slow down, rather than support, construction of new facilities. Implementing a rigid mandatory cost allocation mechanism may result in extensive case-by-case litigation. The uncertainty created by that

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[43] *See* NOPR at P 152.

[44] *See id*. at P 152-153, 171.

litigation will make it highly risky for any project sponsor to commit funds or obtain financing until after the litigation is over. Because the commercial need for an economic project is time sensitive, such delays will result in projects not being built. This seems to be directly at odds with serving "the public's interest in an abundant supply of electric energy throughout the United States with the greatest possible economy."[45]

There is also no reason to suppose that individual proceedings could not address the "free rider" problem or the "risk" to new developers. Transmission owners may always file complaints under Section 206 to the extent they believe beneficiaries of their services are free riding. In addition, to mitigate risk and obtain some certainty in rate recovery, non-incumbent transmission developers may always make a Section 205 filing with the Commission[46] or, following an approach that has been successfully used to encourage development of new projects, petition the Commission for a declaratory order regarding rate recovery for the projects.[47]

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45 *See NAACP v FPC*, 520 F.2d 432, 438 (D.C. Cir. 1975) (explaining public interest under the Federal Power Act).

46 In addition to general rate case filings under Section 205 of the FPA, project developers may seek up-front certainty Section 205 for merchant transmission projects. *See e.g, Montana Alberta Tie, Ltd*., 116 FERC ¶ 61,071 (2006) (accepting merchant transmission proposal in connection with new transmission line from Alberta to Montana); *Conjunction LLC*, 103 FERC ¶ 61,198 (2003) (accepting merchant transmission proposal in connection with new transmission line from upstate New York to New York City); *Northeast Utilities Service Co*., 98 FERC ¶ 61,310 (2002) (accepting merchant transmission proposal in connection with new underwater cable from Connecticut to Long Island); *TransEnergie U.S. Ltd. and Hydro One Delivery Services Inc*., 98 FERC ¶ 61,147 (2002) (conditionally accepting merchant transmission proposal in connection with underwater cable to Ontario).

47 *See e.g., Great River Energy*, 130 FERC ¶ 61,001 (2010) (granting rate incentives for CAPX2020 transmission project); *NorthWestern Corp*., 127 FERC ¶ 61,266 (2009) (granting a petition for declaratory order on the open season and cost allocation for NorthWestern's Collector project); *Green Energy Express LLC*, 129 FERC ¶ 61,165 (2009) (granting petition for declaratory on rate incentives for new transmission project); *Green Power Express LP*, 127 FERC ¶ 61,031 (2009) (same); *Bonneville Power Administration*, 123 FERC ¶ 61,264 (2008) (granting a petition for declaratory order on the Network Open Season of Bonneville to facilitate, among other things, the construction of upgrades for new requested transmission service); *California Independent System Operator Corp*., 119 FERC ¶ 61,061 (2007) (granting a petition for declaratory order regarding a financing mechanism for the construction of interconnection facilities to connect location-constrained resources (*e.g*., wind resources) to the CAISO grid.

Lacking all of these findings of a real industry problem, a final rule adopting the proposed rules would be arbitrary and capricious.[48] As the D.C. Circuit stated in *National Fuel Gas Supply Corp. v. FERC*, "[p]rofessing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decisionmaking."[49]

2. There Is No Reason To Require Modifications To The ColumbiaGrid Cost Allocation Methodologies.

The Commission correctly determined in Order No. 890 that there must be some regional flexibility in a cost allocation mechanism and ColumbiaGrid agrees with the NOPR's recognition of the desirability of continuing to allow such flexibility.[50] ColumbiaGrid's cost allocation methodology directly reflects regional concerns in that it facilitates the active participation of non-public utilities in the transmission planning process.

In the NOPR, the Commission states that a cost allocation method that relies exclusively on a participant funding approach, without respect to other beneficiaries of a transmission facility, exacerbates the "free rider" problem that the Commission described in Order No. 890 and that would not satisfy the Commission's proposed principles.[51] In discussing the various cost allocation methodologies in the regions, the Commission states that ColumbiaGrid utilizes a study committee process whereby alternative cost allocation methods can be proposed for projects within its region, but that if no agreement on cost allocation among the study team participants or the project proponents is obtained, the entities requesting the project will bear the

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48 *See National Fuel Gas Supply Corp.*, 468 F.3d at 844.

49 *See id*. at 843 (*citing Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983)).

50 *See* Order No. 890-A at P 253; NOPR at P 165.

51 *See* NOPR at P 168.

costs.[52] ColumbiaGrid notes that the Commission's discussion in the NOPR appears to describe the cost allocation methodology for Capacity Increase Projects in the ColumbiaGrid planning process, rather than the cost allocation methodologies for other types of projects. ColumbiaGrid requests that the Commission clarify that the cost allocation methodologies to which the NOPR is directed are those in place for economic projects and not for reliability or other types of projects. To the extent the Commission's cost allocation reforms only concern economic projects, ColumbiaGrid notes that the Commission accepted the Capacity Increase Project cost allocation methodology only months ago, as submitted in compliance filings by Avista and PSE.[53] No deficiency in that cost allocation methodology has been shown in the intervening time period.

Deficiencies in an up-front cost allocation methodology are not the true obstacle to construction of interregional projects. It is the experience of Northwest utilities that such projects take years of negotiation, regulatory approval, siting, and construction due to the extensive issues that must be resolved. The issues are numerous and are only beginning to be resolved. For example, uncertainty as to state and federal renewable portfolio standards imposes risks on development of new projects. Further, allocation of the costs of long, multi-system lines will likely require extensive negotiation that cannot be shortened by a Commission rule.

At most, the Commission could consider requirements that call for adjacent systems to coordinate processing of transmission service requests and the development of interregional facilities needed to provide requested transmission service. The gas pipeline industry uses multi-system open seasons with precedent agreements to develop pipeline capacity from source to sink.

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[52] *See id*. at P 128.

[53] *See Avista Corporation*, unpublished letter order, Docket No. OA08-25-003 (Mar. 3, 2010); *Puget Sound Energy, Inc*., unpublished letter order, Docket No. OA08-26-003 (Feb. 25, 2010).

Bonneville's success with its Network Open Season has demonstrated that such a process also works for a single electric transmission system.[54] Merchant transmission developers, such as the Montana-Alberta Tie, have had successful open seasons.[55] The reasons these efforts succeeded were that they were economically feasible for both transmission providers and transmission customers and provided a simple and voluntary mechanism to process the requests.

3. The Commission Should Recognize That A Cost Allocation Methodology Is Not A Rate and That a Cost Allocation Methodology Does Not Recover Costs On Its Own.

One ambiguous aspect of the Commission's cost allocation proposals is the relationship between a cost allocation methodology, as proposed by the Commission, and a rate. Section 205 and Section 206 grant the Commission authority over the rates, terms and conditions of jurisdictional transmission service. Over the years, in FPA Section 205 and NGA Section 4 cases, the Commission has often allowed or disallowed particular cost recovery through rates, depending upon its "used and useful" and prudence tests, or upon the results of appropriate cost allocation. If the Commission disallowed the recovery of costs through rates, this did not mean that the public utility did not have to bear the cost of its investment, but, rather, that the public utility could not recover the cost through its FERC-jurisdictional rates.[56] In a typical scenario, the public utility building a new facility assumes the cost responsibility for it, and seeks to recover its costs through proposed rate filings. The incurrence of cost for new investments may

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54 *See Bonneville Power Administration*, 123 FERC ¶ 61,264 (2008).

55 *See Montana Alberta Tie, Ltd.*, 116 FERC ¶ 61,071 (2006).

56 *See e.g., Colorado Interstate Gas Co. v. Federal Power Comm'n*, 324 U.S. 581, 588-589 (1945).

precipitate a rate filing, or may be a consequence of ratemaking, but it is not, strictly speaking, a rate itself.[57]

The Commission may view cost allocation methodologies as a "practice" affecting rates,[58] but they are closer to simply a rate design than anything else. Courts have recognized that rates are set, in the first instance, by the utilities.[59] Under Section 205 of the FPA, the public utility has the choice among a number of alternative cost allocation and rate design methodologies, with no single method having exclusive claim as being the "right" one.[60] Of course, the public utility must demonstrate that its proposed rates are just and reasonable, and the Commission could find the proposed rates unjust and unreasonable if the underlying cost allocation does not fairly allocate costs.

In ColumbiaGrid's view, the difference between a cost allocation method and a rate is an extremely important one. A particular cost allocation method used in a region's transmission planning process has *no direct impact on rates* unless and until the Commission accepts a rate for filing for a project that reflects that particular cost allocation method. This is so because the cost allocation method does not recover costs on its own and because there would be no rate for a new project in effect prior to a Section 205 filing accepted by the Commission. Only after a rate has become effective can the underlying cost allocation method it employs be said to affect rates. To the extent the cost allocation method underpinning the rate was deemed by the Commission to be unjust and unreasonable, the Commission could reject it when the rate is proposed.

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57 *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) ("all *approved rates* reflect to some degree the costs actually caused by the customer who must pay them") (emphasis added).

58 *See* FPA § 206(a), 16 U.S.C. § 824e(a).

59 *See ISO New England, Inc.*, 113 FERC ¶ 61,055 at P 27 (*citing Sea Robin*, 795 F.2d 182 at 183-84 (D.C. Cir. 1986)).

60 *See Trunkline Gas Co.*, 23 FERC ¶ 61,137 at 61,297 (1983) (interpreting parallel provision of the Natural Gas Act).

The Commission appears to intend that the proposed cost allocation methods would be established prior to the effective date of individual approved rates applying such methods to specific projects; this raises the issue of the legal significance of a cost allocation method. It is unclear how transmission owners would reflect -- in rates that would somehow be applicable to all "beneficiaries" of a project -- the cost allocations developed pursuant to the NOPR; this problem, which could created trapped or unrecoverable costs, is especially critical in regions where there is no RTO tariff with a formula rate that is already designed to operate in conjunction with the cost allocation determinations made by the RTO in the regional transmission planning process. The Commission should clarify whether and how approval of any cost allocation methodologies developed pursuant to this proceeding would constitute a Commission-jurisdictional rate in and of itself and, if not, whether the methodologies would have the type of preemptive effect in state or local rate proceedings that Commission decisions on wholesale rates and allocations of transmission capacity do.[61] The Commission should not require imposition of a cost allocation methodology without ensuring that there is a mechanism, within the Commission's authority, for ensuring recovery of those costs. As discussed below, ColumbiaGrid submits that the Commission does not have such authority.

4. The Commission's Cost Allocation Proposals Are An Unexplained Departure From Prior Precedent and Beyond its Federal Power Act Authority.

The NOPR's cost allocation proposal raises the question of whether the Commission has the authority, consistent with the Federal Power Act, to require public and non-public utilities to make binding determinations of which parties must categorically bear the cost of facilities prior to the development of a project and prior to the filing of actual rates designed to recover those

[61] *See Nantahala Power and Light Co., v. Thornburg*, 476 U.S. 953 (1986); *Mississippi Power & Light Co. v. Mississippi ex. rel. Moore*, 487 U.S. 354 (1988).

costs. At least with respect to non-RTO regions (where there are no regional service tariff rates), it appears that the Commission's proposal of directing public and non-public utilities to adopt a specific cost allocation method in advance could infringe upon a utility's right to propose rates under Section 205 and exceed the Commission's authority.[62]

The Commission's proposal to require the implementation of cost allocation mechanisms that allocate costs involuntarily to "beneficiaries" and in the absence of a filed and approved rate structure, is a significant departure from the Federal Power Act and Commission precedent. The Commission barely acknowledges this shift in policy, stating only that "the circumstances in which the Commission must fulfill its statutory responsibilities [to ensure rates are just and reasonable] change with developments in the electric industry"[63] and "the Commission has previously recognized changes in circumstances . . . warrant changes in the manner by which public utilities recover costs."[64] While the Commission may change its policies, it must clearly explain the statutory basis for requiring such changes.[65]

The Commission suggests that its proposed requirements for cost allocation methodologies are not actually different from its current approach, pointing in support to an isolated sentence in the opinion of the Court of Appeals for the Seventh Circuit in *Illinois Commerce Commission v. FERC*.[66] In that case, the court stated, in dicta, that "To the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have

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62 *See Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 12 (D.C. Cir. 2002).

63 *See* NOPR at P 148.

64 *See id*. at P 149.

65 *See Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 41-42 (1983).

66 576 F.3d 470 (7th Cir. 2009).

been built, or might have been delayed."[67] The Seventh Circuit's statement, however, was in the context of PJM's pricing structure--an RTO with an approved regional tariff rate that could have permitted such cost allocation. The Commission also does not mention that the court's statement is immediately preceded by the statement that "[A]ll *approved* rates [must] reflect to some degree the costs *actually caused* by the customer who must pay them."[68] The court then stated, "Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[69] Thus, this case does not support the NOPR's approach of allocating costs in the absence of an approved rate or a contractual relationship between transmission owners and presumed beneficiaries. Outside of the context present in that case, the Commission's reliance on *Illinois Commerce Commission* to extend the cost causation principle to allocate costs to any entity that may be said to "benefit" from a project is misplaced. In this regard, it is important to emphasize that ColumbiaGrid is *not* an RTO and the ColumbiaGrid members are *not customers* of ColumbiaGrid.

The Commission also cites the D.C. Circuit's findings in *Midwest ISO Transmission Owners, et al. v. FERC* to support the concept that it may allocate costs involuntarily to parties that benefit.[70] In that case, the D.C. Circuit affirmed the Commission's decision to allocate the administrative costs of the Midwest ISO to all its customers, including customers under agreements of Midwest ISO transmission owners that were "grandfathered" at the creation of the Midwest ISO (and which were not in a contractual relationship with the Midwest ISO). The

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67 *See id.* at 476.

68 *See id.* (emphasis added).

69 *Id.*

70 373 F.3d 1361 (D.C. Cir. 2004)

grandfathered customers in that case, the court found, benefited from the increased reliability and security provided by the Midwest ISO, which also had operational authority over, and provided transmission service for, all of the transmission loads, including the grandfathered customers. Although there was no direct contractual relationship between the grandfathered customers and the Midwest ISO, there was between the Midwest ISO and the transmission owners with whom the customers had "grandfathered" service. ColumbiaGrid disagrees that there is any nexus between the court's detailed findings of services provided by the Midwest ISO (as well as a weighing of the benefits and costs in that case) and the more generic rule proposed in the NOPR – at least to the extent it purports to apply to transmission planning organizations that are not also RTOs.

In fact, court precedent holds that the Commission cannot use its authority to force customers to pay for additional "benefits" above and beyond their existing service. In *Exxon Mobil Corp. v. FERC*, the court stated the following with respect to Section 5 of the Natural Gas Act (the counterpart of Section 206 of the Federal Power Act): "Under § 5, FERC may reject unjust and unreasonable rates and prescribe a new rate that is just and reasonable. It may not, however, require distributors to accept or to pay for additional service."[71] Thus, rates under Sections 205 or 206 of the Federal Power Act can only be imposed on customers receiving jurisdictional transmission service from a public utility. Costs cannot be recovered from entities that are not customers receiving such service.

[71] 430 F.3d 1166, 1176-77 (D.C. Cir. 2005) (*citing Alabama-Tennessee Natural Gas Co. v. Fed. Power Comm'n*, 417 F.2d 511, 514-15 (5th Cir. 1969) ("[T]he Commission has no authority to require a local distributor to contract for, purchase, or accept delivery of natural gas.").

5. The Commission Should Clarify Certain OATT Reforms. A Public Utility Transmission Provider Should Not And Cannot Be Expected To Unilaterally Bind Other Transmission Providers -- Jurisdictional And Non-Jurisdictional -- To Follow Any Particular Method For Cost Allocation.

The rigidity of the Commission's proposed reforms could pose difficulties in the ColumbiaGrid region because it might curtail the flexibility and cooperative approach that is so important to its planning participants, including the many participants that are non-public utilities over whom the Commission has limited jurisdiction.[72]

For example, the Commission proposes that each public utility transmission provider include in its OATT the process used in its regional transmission planning process for evaluating whether to include a proposed transmission facility in the regional transmission plan.[73] In addition, the Commission proposes that, in non-RTO/ISO transmission planning regions, each public utility transmission provider located within the region must set forth in its tariff the method or methods for cost allocation used in its transmission planning region.[74] In light of the decision of the Court of Appeals for the Ninth Circuit in *Bonneville Power Administration v. FERC*,[75] however, it is clear that non-public utilities cannot be *required* by FERC rule to participate in cost allocations regardless of whether such mechanisms are included in a public utility transmission provider's OATT.

Thus, ColumbiaGrid requests that the Commission clarify that a public utility transmission provider should not and cannot be expected to unilaterally bind all other transmission providers – jurisdictional and non-jurisdictional – to follow any particular cost

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72 *See* Federal Power Act, Section 201(f).

73 *See* NOPR at P 92.

74 *See id*. at P 159.

75 422 F.3d 908 (9th Cir. 2005).

allocation method. (This issue arises, for example, if voluntary efforts to arrive at agreement among all jurisdictional and non-jurisdictional transmission providers in a non-RTO/ISO region as to the method or methods for cost allocation are unsuccessful.).

E. The Proposed Reforms Exceed the Commission's Authority Under Section 202 of the Federal Power Act.

The NOPR raises other, basic questions about the nature of the Commission's authority under the FPA. The Commission's proposal to require transmission providers in the various regions to enter into agreements on cost allocation methods to recover the costs of new transmission facilities is at odds with Section 202(a) of the Federal Power Act, which provides that 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 energy.[76] Under Section 202(a), the Commission has a duty "to promote and encourage such interconnection and coordination within each district and between such districts."[77] The Commission may only compel interconnection and coordination within and between districts pursuant to the procedures of Section 202(b).[78]

The D.C. Circuit has explained that this section "has been definitively interpreted to make clear that Congress intended coordination and interconnection agreements be left to the 'voluntary' action of [public utilities]."[79] In a key case discussing the Commission's authority under Section 202(a), *Central Iowa Power Cooperative v. FERC*, the D.C. Circuit explained that "Congress has decided, as a matter of general policy, that power pooling arrangements, rather

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[76] 16 U.S.C. § 824a.

[77] *See id*.

[78] The Commission may also compel interconnections between utilities pursuant to Section 211 of the FPA.

[79] *See Atlantic City Electric Co. v. FERC*, 295 F.3d 1, (D.C. Cir. 2002).

than unrestrained competition between electric facilities, are in the public interest."[80] In *Central Iowa Power Cooperative*, the D.C. Circuit upheld the Commission's decision not to require the Mid-Continent Area Power Pool to expand the range of services of its power pool agreement to include, among other things, single system planning with central dispatch. The D.C. Circuit explained how the Commission's decision was consistent with the purposes of Section 202(a):

> Notwithstanding the desirability of coordination of electric systems, however, Congress decided to make such coordination voluntary with limited exceptions. Congress was convinced that "enlightened self-interest" would lead utilities to engage voluntarily in power planning arrangements, and it was not willing to mandate that they do so. Given the expressly voluntary nature of coordination under section 202(a), the Commission could not have mandated adoption of the Agreement, and failure of the MAPP participants to establish a fully integrated electric system could not justify rejection of the Agreement filed.[81]

In the NOPR, the Commission appears to move beyond promotion and encouragement to mandating the particular types of coordination and interconnection that public and non-public utilities must undertake, including mandating the development of cost allocation methodologies to facilitate competition between electric facilities. ColumbiaGrid also notes the importance of recognizing Congress' intent in adopting Section 202(a):

> The committee is confident that enlightened self-interest will lead the utilities to cooperate with [FERC] in bringing about the economies which alone can be secured through the planned coordination which has long been advocated by the most able and progressive thinkers on this subject.[82]

This voluntary coordination is, in fact, what is currently occurring in the ColumbiaGrid region and has been since before the issuance of Order No. 890. The Commission should not

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80 606 F.2d 1156, 1162 (D.C. Cir. 1979).

81 *See id*. at 1167-68.

82 *See Municipalities of Groton v FERC*, 587 F.2d 1296, 1298 n.2 (D.C. Cir. 1978)

upset these efforts through the proposed reforms, which threaten the collaboration in the Pacific Northwest and would impose significant burdens.

IV. CONCLUSION

ColumbiaGrid appreciates the opportunity to participate in this proceeding and requests that the Commission consider the comments submitted herein.

Respectfully Submitted,

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