UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Competitive Transmission Development Technical Conference	Docket No. AD16-18-000

COMMENTS OF
TRANSMISSION ACCESS POLICY STUDY GROUP

Pursuant to the August 3, 2016 Notice Inviting Post-Technical Conference Comments and the August 15, 2016 Notice of Extension of Time, the Transmission Access Policy Study Group ("TAPS") comments on the Commission's questions, which relate to the competitive development process and other Order 1000[1] interregional and regional planning issues.

TAPS members recognize the importance of a robust transmission grid, and have long advocated policies to get needed transmission built. TAPS, which generally supported Order 1000, appreciates the Commission's interest in assessing the effectiveness of that Rule in promoting more efficient and cost-effective transmission expansion where needed. We therefore welcome the opportunity to comment on these questions regarding the treatment of "cost-contained bids" in Order 1000 processes and other Order 1000 implementation issues.

As discussed in greater detail below, especially in light of the limited experience to date with such bids, TAPS opposes any modification to the Commission's existing

[1] Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011) ("Order 1000"), *reh'g denied*, Order No. 1000-A, 77 Fed. Reg. 32,184 (May 31, 2012), 139 FERC ¶ 61,132 (2012) ("Order 1000-A"), *on reh'g*, Order No. 1000-B, 77 Fed. Reg. 64,890 (Oct. 24, 2012), 141 FERC ¶ 61,044 (2012), *review denied sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (per curiam), *reh'g en banc denied*, No. 12-1232 (D.C. Cir. Oct. 17, 2014).

Incentives Policy (including with respect to performance-based rates) or its Discounted Cash Flow methodology. In particular, TAPS strongly opposes proposals to grant a return on equity ("ROE") incentive simply for the willingness of a developer, in an effort to improve its chance of being selected, to voluntarily include a cost containment provision in its competitive proposal. TAPS also believes it is premature to revisit Order 1000's interregional coordination requirements at this time, as some regions have not yet completed even one full interregional cycle.

TAPS believes, however, that there could be potentially significant consumer benefits from properly configured cost-contained bids in some circumstances. TAPS urges the Commission to initiate a rulemaking to develop a standardized and comprehensive cost containment provision—including separately specifying the ROE, the capital structure, and any incentives the developer reserves the right to request—and to assure that all competitive bids are fully transparent. TAPS also recommends how bids with cost containment provisions should be treated in the selection processes of various types of regions, recognizing that treatment should depend on the characteristics of the region and its Order 1000 process.

INTEREST OF TAPS AND COMMUNICATIONS

TAPS is an association of transmission-dependent utilities ("TDUs") in more than 35 states, promoting open and non-discriminatory transmission access.[2] As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members recognize the importance of both open access and a robust

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[2] David Geschwind, Southern Minnesota Municipal Power Agency, chairs the TAPS Board. Jane Cirrincione, Northern California Power Agency, is TAPS Vice Chair. John Twitty is TAPS Executive Director.

transmission grid to competitive generation markets, and have long advocated policies to get needed transmission built. *See* TAPS, *Effective Solutions for Getting Needed Transmission Built at Reasonable Cost* (June 2004).[3] In addition, TAPS members pay transmission rates that are substantially increased when the Commission approves above-cost incentives, and participate, when possible, in transmission development projects.

TAPS recognizes the critical roles played by an open, inclusive and transparent planning process, and fair cost allocation methodologies in achieving needed transmission expansion at reasonable cost. TAPS has actively participated in the Order 1000 rulemaking process, as well as proceedings pertaining to the Commission's transmission incentive policies.

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COMMENTS

I. PANEL ONE: COST CONTAINMENT PROVISIONS IN COMPETITIVE TRANSMISSION DEVELOPMENT PROCESSES[4]

1. How do public utility transmission providers in regions compare proposals with and without cost containment provisions for transmission facilities eligible to be selected in a regional transmission plan for purposes of cost allocation? Please provide examples. What, if any, guidance or

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[3] *Available at* http://www.tapsgroup.org/wp-content/uploads/2013/01/effectivesolutions2.pdf.

[4] To facilitate review, TAPS' comments are organized in the same manner as the Commission's questions.

requirements should the Commission provide with respect to the comparison of proposals with and without cost containment provisions?

Comments: Competition in the selection of the most cost-effective and efficient project can spur innovation and cost-cutting by developers that result in lower costs to consumers. On the other hand, transmission cost estimates are often inaccurate. In addition, effective cost comparison may be impeded by a number of factors, including: failure to disclose rate elements that the developer may request later and will increase costs to consumers (e.g., ROE, capital structure, incentives); absence of apples-to-apples competition in the selection process (e.g., in competitive processes that use the sponsorship model, where developers may be proposing different solutions for an identified need, instead of bidding on construction of a solution that has already been defined); and advantages of particular competitors (e.g., incumbent transmission owners that own the right-of-way).[5]

As discussed in response to Panel 1, Question 3 below, for cost containment provisions to play an effective role in the Order 1000 project selection process, they must be standardized and comprehensive (i.e., containing all costs, without "exemptions")—including separately specifying the ROE, the capital structure, and the incentives that will be requested—so that everyone knows what they mean, and the cost containment provisions of different competitors can be accurately compared. In responding to this question, we therefore focus on how to compare: (1) a proposal that includes and is fully

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[5] Order 1000, P 319, makes clear that the Commission's "reforms are not intended to alter an incumbent transmission provider's use and control of its existing rights-of-way." The Commission further explains that "this Final Rule [does not] grant or deny transmission developers the ability to use rights-of-way held by other entities, even if transmission facilities associated with such upgrades or uses of existing rights-of-way are selected in the regional transmission plan for purposes of cost allocation. The retention, modification, or transfer of rights-of-way remain subject to relevant law or regulation granting the rights-of-way." *Id.* *See also* Order 1000-A, P 427.

subject to a standardized and comprehensive cost containment provision that meets Commission-approved requirements, with (2) a proposal that does not include the Commission-approved standardized, comprehensive cost containment provision. We also address how bids with non-standardized cost containment provisions should be treated in competitive processes.

In RTOs,[6] if planning is robust and the "competitive solicitation" model is adopted, consumers can benefit from standardized, comprehensive cost containment bids. Under those conditions, such bids should be preferred over proposals without cost containment, absent unusual circumstances (e.g., a significantly lower non-cost-contained estimate using advanced technology; other reasoned basis for confidence that the non-cost-contained bid will result in lower cost to consumers[7]).

Cost containment provisions that do not meet these standardization requirements should not be entitled to the same weight in the RTO selection process. The range, scope, and design of potential non-standardized cost containment measures are virtually unlimited. RTOs cannot reasonably be expected to develop the expertise necessary to deconstruct complex, partial cost containment provisions, so that their costs, risks, and expected values can be compared with other dissimilar bids on an apples-to-apples basis. Thus, if a developer wants its cost containment commitments to provide an advantage in the project selection process, it should be required to offer standardized cost containment measures that RTOs, the entities required to pay for regional projects, and the Commission can fully understand. For the same reason, bids that use non-standardized

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[6] Independent System Operators and Regional Transmission Organizations are collectively referred to as "RTOs."

[7] E.g., the incumbent owns the right-of-way, which the competing developer would need to acquire.

cost containment provisions should be treated the same as cost estimates with no cost containment provisions.

Even standardized cost containment provisions, moreover, should be favored only if the RTO's competitive process is based on the "competitive solicitation" model. As discussed in response to Panel 5, Question 5, TAPS advocates use of the competitive solicitation model—which invites competing bids for an already selected, well-defined transmission solution—where the RTO's planning process for developing and selecting solutions to transmission needs is robust. However, to the extent that the Commission allows RTOs to use the "sponsorship model"—which invites competitors to propose alternative solutions to address an identified need—cost will be just one of many factors relevant to project selection, frustrating the ability to make an apples-to-apples comparison, and it is inappropriate to elevate cost and cost containment over other selection criteria.

Cost containment provisions should not be generically favored in non-RTO regions. In non-RTO regions, the sponsorship model is better suited to identifying more efficient and cost-effective projects, as discussed in our response to Panel 5, Question 5. As in situations where the Commission allows use of the sponsorship model in RTOs, it is unclear how much (if at all) proposals with cost containment provisions (either standardized or non-standardized) should be advantaged in non-RTO region selection processes, as compared with proposals with cost estimates that do include such provisions.

At minimum and in any event, for any Order 1000 selection process to be credible, all bids should be transparent, with all elements (including the ROE, the capital structure, and the incentives to be requested), and any cost containment provisions, clearly disclosed. Otherwise, the Commission's requirements for a transparent non-discriminatory selection process in which cost estimates are scrutinized (Order 1000-A, P 455) cannot be satisfied. *See also* Order 1000, P 328 (requiring transparency and stakeholder coordination, culminating "in a determination that is sufficiently detailed for stakeholders to understand why a particular transmission project was selected or not").

2. *What can public utility transmission providers in regions do to ensure there is sufficient transparency for transmission developers to understand: a) how a proposal will be evaluated in advance of the proposal submission; b) developments, if any, that occur during the evaluation process; and c) the reasons the selection decision was made? Should cost containment provisions in all proposals, and not just winning proposals, be made known? What, if any, guidance or requirements should the Commission provide with respect to this issue?*

Comments: The Commission has long recognized the importance of transparency in instilling confidence in transmission planning procedures and in preventing undue discrimination. Order 890 was premised on "improv[ing] transparency" to "reduce opportunities for undue discrimination, and increase [the Commission's] ability to detect undue discrimination."[8] To achieve this goal, the Commission required transmission providers ("TPs") "to reduce to writing and make available the basic methodology, criteria, and processes they use to develop their transmission plans." Order 890, P 471. In Order 1000, the Commission reemphasized its commitment to transparency in the planning process[9] as well as project selection. As

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[8] Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266, 12,275 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, P 51 (2007) ("Order 890"), *order on reh'g and clarification*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 Fed. Reg. 61,511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).

[9] *See, e.g.*, Order 1000, App. C (*Pro Forma* Open Access Transmission Tariff Attachment K, requiring Transmission Providers to provide in their transmission planning processes sufficient detail for Transmission Customers to understand, *inter alia*, "[t]he methodology, criteria, and processes used to

discussed above, Order 1000, P 328, expressly required transparency in the selection process, with sufficient details to enable stakeholders to understand why a particular transmission project was selected or not selected.[10]

The Commission should reinforce Order 1000's requirements and objectives by insisting on maximum transparency in all phases of the transmission planning and selection process. Such transparency requires disclosure to all stakeholders (potentially subject to appropriate non-disclosure agreements)[11] of the cost details of all proposals—not just the winning proposal—that are submitted through these processes. Thus, all cost containment provisions, as well as developer-requested ROEs and capital structures, and any incentives the developer reserves the right to request, should be disclosed. Transparent cost information is especially important because the ratepaying public bears the ultimate burden of funding the transmission projects, but is not a party to the selection process.[12] Requiring maximum transparency will facilitate development of a record that can be used to evaluate the efficacy of competitive processes, understand their benefits,

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develop a transmission plan; [and] [t]he method of disclosure of criteria, assumptions and data underlying a transmission plan."). Order 1000-A, P 281 & n.330, reiterated the importance of such openness, subject to appropriate provisions to protect commercially sensitive and confidential information in a manner that allows stakeholders to effectively participate and replicate the results of planning studies.

[10] *See also* Order 1000, P 315 (reaffirming Order 890's requirement that TP Open Access Transmission Tariffs ("OATTs") identify how the TP will evaluate and select among competing solutions—i.e., the criteria to "evaluate the relative economics and effectiveness of performance for each alternative offered for consideration").

[11] *See* Order 890, PP 460, 471-72 (requiring transmission providers to develop safeguards to "protect against inappropriate disclosure of confidential information or CEII").

[12] *See* Peggy Bernardy, California Department of Water Resources, Transcript of Competitive Transmission Development Technical Conference, June 27–28, 2016, June 28 at 21:8–14, Docket No. AD16-18-000, eLibrary Nos. 20160707-4001, 20160628-4014 ("Tech. Conf. Tr."). ("There's a lack of transparency that we would like to explore remedying. We are not able to see the bids at the ISO when they are put in. We are not able to review at all the ISO's selection process until well after the fact and then once the cases got to FERC for rate review during the summary process we've not been able to see the bids that were put in. [W]e could get that in discovery at hearing but not prior to that and I feel that some additional transparency in that regard would assist ratepayers.").

and inform Commission review of rate filings and disputes regarding the facilities that result from the processes.[13]

In addition, transparency would be enhanced by requiring greater clarity on the weighting of factors to be used in project selection. That is more challenging in regions that use the sponsorship model (which is the preferable model for non-RTO regions). However, if an RTO's planning process for developing and selecting solutions to identified transmission needs is robust, and competitor bids include cost containment provisions that are standardized and comprehensive, as discussed below, RTOs should use a competitive solicitation model, with clear selection criteria weighted heavily toward cost.[14] *See* response to Question 1 above, Question 3 below, and to Panel 5, Question 5.

3. *Should there be standardization of cost containment provisions or exclusions of certain costs to facilitate comparison of proposals with differing cost containment provisions? If so, what role should the Commission and/or public utility transmission providers in regions play in pursuing standardization?*

4. *What quantitative and qualitative methods can public utility transmission providers in regions use to evaluate proposals with different cost containment provisions, such as cost caps with different exclusions or that cap different components of the revenue requirement?*

Comments: The potential variety of cost containment provisions, and exemptions to those provisions, is virtually unlimited, constrained only by the imagination of the lawyers, risk managers, and accountants of transmission developers. We recognize that developers at the Technical Conference urged against standardization,

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[13] *See, e.g.* George Dawe, Duke American Transmission Company, Tech. Conf. Tr. June 28 at 13:18–25 ("[M]any of the competitive proposal evaluations and comparative analyses conducted by RTOs have resulted in controversial determinations, raising questions about the transparency and subjectivity of the administration of these processes. Confidence in the RTO evaluation process is of utmost importance.").

[14] TAPS is not aware of any RTO with a competitive process that currently meets these criteria.

raising among other things regional differences, evolving markets, and the potential for innovation.[15]

However, "innovation" in making bids appear more cost-contained than they are is not the type of innovation the Commission is seeking to incent through Order 1000's process for selection of more cost-effective and efficient projects for regional cost allocation. Absent standardization, it will be virtually impossible for transmission providers or the Commission to assess and compare competing proposals in a fair and transparent manner. To make such comparisons, TPs must reduce each proposal's disparate elements to a set of common estimated cost and risk indices. Transmission providers lack the internal expertise to do so accurately.

Even if an individual TP could secure that expertise, the costs would be high, and the results would at best be rough, requiring complicated weighting of different types of risk. Such an analysis would not provide stakeholders with adequate assurance that the TP's ultimate choice was non-discriminatory, as Order 1000, P 328, requires.[16] This will undermine the ability to achieve Order 1000's objective of reducing costs to consumers by selecting the more cost-effective and efficient project, as well as the credibility of the selection process.

For this reason, TAPS urges the Commission to initiate a rulemaking process to develop a standardized cost containment provision that will enable transmission providers and the Commission to fairly and fully compare the costs of competing transmission

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[15] *See, e.g.,* Sharon Segner, LS Power Development, LLC, Tech. Conf. Tr. June 27 at 24:17–22; *see also* Anthony Ivancovich, California Independent System Operator, Tech. Conf. Tr. June 27 at 52:15–18.

[16] *See, e.g.,* Steve Herling, PJM Interconnection L.L.C., Tech. Conf. Tr. June 28 at 212:13–25 (noting that stakeholders need to understand how a decision is made).

development proposals. The resulting standardized cost containment provision should be comprehensive and fully inclusive (i.e., no hidden loopholes or exemptions), and should separately state the ROE, the capital structure, and any incentives the developer may seek.[17] As a result, all cost elements will be transparent, to facilitate an informed comparison in the selection process, as well as an understanding as to how the developer envisions the cost containment provision would operate when incorporated in its proposed rate. *See* response to Panel 2, Question 4. The rule need not require that all competitive developers only submit bids that conform to this standard. However, only bids that include such provisions will be accorded cost containment weight in an RTO's competitive solicitation process. *See* Panel 1, Question 1.

While TAPS prefers that the Commission develop a standardized cost containment provision that is comprehensive—i.e., fully inclusive and containing all costs without exemptions—it is possible that consumers could realize much of the benefit from competition if cost containment bids were standardized to require inclusion of ROE, capital structure, and incentives, but with other costs being recovered on a full cost-of-service basis. Transmission construction is a mature technology, so for most projects there may be only insignificant variation in the unit costs of equipment and construction incurred by different competitors.[18] Other cost factors, however, may be impossible to pin down precisely prior to bidding. For example, competitive developers that do not

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[17] *See, e.g.,* Commissioner Cheryl LaFleur, Tech. Conf. Tr. June 28 at 55:20–57:1 (asking whether the Commission would be leaving money on the table for consumers, if ROE is excluded from the competitive process, preventing developers from competing on how much risk they are willing to take).

[18] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 147 FERC ¶ 61,127, P 344 (2014) (noting MISO's assertion that its proposed 30 percent weight for cost estimates is reasonable "because such estimates are less variable under its competitive bidding framework than under a sponsorship approach") (subsequent history omitted).

already own the necessary rights-of-way will have to factor uncertainty with respect to siting and environmental mitigation requirements into the cost containment provisions included with their bids. To the extent those sources of uncertainty cannot be mitigated in advance, competitive developers will either include significant risk premiums in their estimates, driving up consumer costs, or drop out of the competition. Thus, competition on ROE, capital structure, and incentives may well be the primary potential source of significant cost savings for consumers.

In any event, the Commission should require that every bid—whether cost-contained or not cost-contained—be transparent. The Commission should require clear identification of all elements, including ROE, capital structure, any incentive the developer reserves the right to seek, and any proffered cost containment provisions. The Commission should also require a clear explanation of what is and isn't covered by any proposed cost containment provisions, recognizing that the task of assessing the impact to consumers of varied cost containment exemptions will still be difficult and expensive.

II. PANEL TWO: COMMISSION CONSIDERATION OF RATES THAT CONTAIN COST CONTAINMENT PROVISIONS AND RESULT FROM COMPETITIVE TRANSMISSION DEVELOPMENT PROCESSES

1. *Should the Commission have a role in evaluating the rate-related components of competing proposals for transmission facilities eligible to be selected in a regional transmission plan for purposes of cost allocation (e.g., terms of cost containment provisions, rate of return, transmission incentives) before the public utility transmission providers in a region select a proposal? If so, what role? What steps could the Commission take to prevent such a role from creating undue delays in transmission planning processes?*

Comments: As discussed in response to Panel 1, Question 3 above, TAPS urges the Commission to initiate a rulemaking process to develop a standardized cost containment provision that transmission providers can rely upon in comparing the costs of competing transmission development proposals. TAPS urges the standardized cost containment provision be comprehensive and fully inclusive—including ROE, capital structure, and any incentive the developer may seek. A bid that uses the standardized cost containment provision would then get significant weight in an RTO's competitive solicitation process. *See* Panel 1, Question 1.

No other change in the Commission's pre-selection role is warranted. The Commission already provides developers with the option to make formula rate filings in advance of selection that provide certainty on how prudently incurred costs for projects, if selected, will be recovered, as well as ROE and capital structure and the terms for recovery of certain non-ROE incentives.[19] The 2012 Policy Statement on Promoting Transmission Investment Through Pricing Reform[20] and the cases applying it provide effective guidance on the availability of other incentives, should the developer choose to seek them.

To the extent the developer reserves the right to seek incentives, those incentives must be identified in the bid so their impact on consumers can be evaluated in the selection process. However, any effort to interject an expedited Commission determination during the selection process will likely unduly delay the process without providing the certainty developers seek (because of the potential for rehearing and appeal), while impeding the Commission's ability to fully perform its statutory obligations to ensure just and reasonable transmission rates.

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[19] *See, e.g.*, *NextEra Energy Transmission West, LLC*, 154 FERC ¶ 61,009 (2016); *DesertLink, LLC*, 156 FERC ¶ 61,118 (2016).

[20] 141 FERC ¶ 61,129, P 28 (2012) ("2012 Policy Statement").

2. *What types of performance-based rates could the Commission accept to reduce asymmetrical risk?*

The Federal Power Act ("FPA") is a consumer protection statute. As the Supreme Court recently reaffirmed, "[t]he statute aims to protect 'against excessive prices.'"[21] The Act does not allow, let alone require, "symmetry" that would permit transmission developers to earn excessive returns. Thus, especially where a developer voluntarily undertakes the risks associated with submitting a bid with cost containment provisions in an effort to enhance the likelihood that its bid will be selected, it would be inconsistent with the Act to institute ratemaking measures to protect developers from "asymmetrical risk." Indeed, in *Federal Power Commission v. Sierra Pacific Power Co.,* 350 U.S. 348, 354-55 (1956), the Supreme Court concluded that the Commission could not find a freely entered contract unjust and unreasonable simply because it proved unprofitable to the supplying utility:

> [W]hile it may be that the Commission may not normally impose upon a public utility a rate which would produce less than a fair return, it does not follow that the public utility may not itself agree by contract to a rate affording less than a fair return or that, if it does so, it is entitled to be relieved of its improvident bargain.

In such cases, the Commission's sole concern should be whether the rate is so low as to adversely affect the public interest (when the low rate would impair the financial ability

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[21] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760 (2016), slip op. at 28 ("*FERC v. EPSA*"), quoting *Penn. Water & Power Co. v. FPC*, 343 U.S. 414, 418 (1952); *see Gulf States Util. Co. v. FPC*, 411 U.S. 747, 758 (1973). *See FERC v. EPSA*, slip op. at 14 (stating that "the contrary view would conflict with the Act's core purposes by preventing all use of a tool that no one (not even EPSA) disputes will curb prices and enhance reliability in the wholesale electricity market"); *id*., slip op. at 29 ("We will not read the FPA, against its clear terms, to halt a practice that so evidently enables the Commission to fulfill its statutory duties of holding down prices and enhancing reliability in the wholesale energy market."). *See also Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959), construing the purpose of the analogous Natural Gas Act (Congress intended to afford the public a "complete, permanent and effective bond of protection from excessive rates and charges").

of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory)—what has been termed the "practically insurmountable" standard.[22] The Supreme Court's protection of contracts in *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1*, 554 U.S. 527, 551 (2008), would support holding a developer to the cost containment commitments made in its voluntarily submitted bid, while preserving full Commission scrutiny of tariff charges to the public for monopoly transmission service to ensure their justness and reasonableness.

FPA Section 219(a)'s provision for incentive-based (including performance-based) rates is expressly focused on benefitting consumers. In addition, Section 219(d) subjects all such rates to the requirements of FPA Sections 205 and 206, that all rates, charges, and terms and conditions be just and reasonable and not unduly discriminatory. Consistent with that mandate, Order 679's[23] implementation of Section 219 restricts incentive returns to the high end of the zone of reasonableness, as determined by the Commission's DCF analysis.[24] To protect consumers, it also requires evaluation of the package of incentives as a whole. Order 679-A, P 27. The 2012 Policy Statement fine-tuned that analysis by requiring applicants to first examine the use of risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges (2012 Policy Statement, P 11). Among other things, the 2012 Policy Statement also required applicants for ROE adders to include a commitment to limit the rate base value

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[22] *Papago Tribal Auth. v. FERC*, 723 F.2d 950, 954 (D.C. Cir. 1983).

[23] Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) ("Order 679"), *on reh'g*, Order No. 679-A, 72 Fed. Reg. 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006) ("Order 679-A"), *clarified*, 119 FERC ¶ 61,062 (2007).

[24] *See* Order 679-A, PP 64, 67-70.

to which the adder is applied, such that it is capped in some reasonable fashion by the project's expected rather than final cost (*id.* PP 28-29).

Similarly, the Commission has stated that performance-based rates must provide quantifiable benefits to consumers:[25]

> All [incentive rate] proposals must include a quantified estimate of the consumer benefits compared to cost-of-service regulation (i.e., a comparison of projected cost-of-service rates to prospective rates under the proposed incentive rate mechanism), and a realistic estimate of the program's prospects for success and the risks of failure. The projected cost-of-service rates will serve as an overall cap on incentive rate increases to limit consumer risk. The cap must be designed to ensure that the incentive rate is no higher than it otherwise would have been under the projected traditional cost-of-service ratemaking [for the period of the incentive rate].

The 1992 Policy Statement recognized that because incentive ratemaking mechanisms based on performance targets were an experiment, they must include specific procedures and a time certain for Commission review. *Id.* It also noted the importance of establishing that the starting "base" rate is just and reasonable. *Id.*; *see also id.* at 61,592 (stating a key issue to be addressed is "how to set the targets," and noting the goal that "the overall effect of the performance targets remain[] neutral with respect to operations and ultimately rates"). The 1992 Policy Statement recognized that due to "[u]npredictable changes," incentive rates must be "reexamined in a comprehensive rate filing," and required inclusion of triggers for periodic rate review (e.g., if the rate of return becomes greater than an agreed ceiling, or after some stated time interval). *Id.*

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[25] Policy Statement on Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, 61 FERC ¶ 61,168, at 61,590 (1992) ("1992 Policy Statement") (footnote omitted).

Consistent with its 1992 Policy Statement, before introducing any new performance-based rates into electric transmission, the Commission must take a hard look and support any such decision with hard data. It also needs to consider the trickiness of establishing targets for performance-based rates that fairly protect consumers. For example, with the best information on cost and risk in the developer's control, it will be challenging to establish a realistic base rate and performance target that do not make it more likely that developers, rather than consumers, will benefit. A more even-handed performance-based rate is certainly preferable to one structured only to provide upside benefits to the developer.[26] However, in the absence of a reliable mechanism to establish a reasonable base rate and performance target, even a performance-based rate that appears designed to provide benefits to consumers may in fact operate in a one-sided manner, allowing significant above-cost recoveries and thereby undermining the FPA's assurance of just and reasonable rates for a monopoly service.

3. *The Commission has accepted proposals to allow incumbent and non-incumbent transmission developers to recover, under certain circumstances, costs associated with developing transmission projects that are proposed but not selected in a regional transmission plan for purposes of cost allocation. [footnote omitted] Should the Commission reexamine, in general, whether such costs may be recovered?*

Comments: As the question notes, the Commission has accepted proposals to allow non-incumbent transmission developers to establish regulatory assets to enable them to seek recovery, under certain circumstances, of costs associated with developing unsuccessful competitive bids, on the theory that to do otherwise would unduly discriminate against non-incumbent developers, as compared with incumbent

[26] Peggy Bernardy, California Department of Water Resources, Opening Statement for the Competitive Transmission Development Technical Conference, June 27–28, 2016, at 5, Docket No. AD16-18-000 (June 30, 2016), eLibrary No. 20160630-4014.

transmission owners which may include their planning-related costs in rates.[27] However, where incumbent Transmission Owner ("TO")/TP or non-incumbent developers choose to compete for project selection for regional cost allocation, it would be more appropriate to exclude *both* from recovery of unsuccessful bidder costs. At minimum, the impact of unsuccessful bid costs should be made transparent in future bids, so those cost impacts can be taken into account in evaluating future bids.

We recognize that incumbent TPs/TOs have planning obligations under North American Electric Reliability Corporation ("NERC"), Commission, and applicable RTO requirements, and they should be able to recover under the relevant OATT costs incurred to meet those obligations. Incumbent transmission providers have an obligation to serve, and to plan and expand the transmission system to meet NERC and Commission requirements and ensure transmission adequacy. They also have the obligation to conduct the Order 1000 planning process pursuant to their tariff. Incumbent TPs should not bear the risk that they will be prevented from recovering the costs of conducting the Order 1000 process, or the costs of planning and developing projects to meet these requirements—e.g., through inclusion of such projects in the underlying regional plan—even if others ultimately seek to compete to develop a more cost-effective and efficient alternative project through the Order 1000 selection process. Likewise, costs incurred by

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[27] *See, e.g., Midwest Power Transmission Ark.*, 152 FERC ¶ 61,210, P 17 (2015) (allowing establishment of a regulatory asset for potential later recovery of unsuccessful bidder costs); *Xcel Energy Southwest Transmission Co., LLC*, 149 FERC ¶ 61,182, PP 33, 94 (2014) (same). While allowing deferral of such costs in a regulatory asset, ultimate recovery will depend on a demonstration in a future FPA Section 205 filing of their justness and reasonableness. *Midwest Power Transmission Ark.*, 152 FERC ¶ 61,210, P 18; *Xcel Energy Southwest Transmission Co., LLC*, 149 FERC ¶ 61,182, P 35. To the best of TAPS' knowledge, the Commission has not yet acted on a request for recovery of such regulatory assets.

incumbent transmission owners to fulfill planning obligations under applicable RTO agreements and tariffs should continue to be recoverable under the RTO's tariff.[28]

Allowing recovery of such required planning costs by incumbents, however, does not mean that non-incumbents that voluntarily choose to compete in the Order 1000 project selection process should also be assured recovery of their failed bid's development costs. Such bidders are not similarly situated to TOs/TPs performing mandatory planning functions and should not be allowed to charge captive ratepayers for their unsuccessful project proposals. To assure comparability, to the extent that incumbent TOs/TPs (or their affiliates) go beyond their required planning obligations and voluntarily seek to compete for selection as more cost-effective and efficient projects subject to regional cost allocation, the incumbent TO/TP's unsuccessful bidder costs should be treated in the same way as the development costs of an unsuccessful non-incumbent bid.[29] Thus, TAPS urges the Commission not to allow cost recovery of bid development costs by unsuccessful bidders—whether an incumbent TO/TP, an affiliated developer, or a non-incumbent developer—that elect to compete for selection as a more cost-effective and efficient regional project.

There is no need to incent submission of bids that are not the most cost-effective and efficient by requiring customers to subsidize unsuccessful bidders. Indeed, such

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[28] Similarly, in the event that no acceptable competitive proposal is submitted, an incumbent TO/TP's costs of fulfilling an obligation to build under applicable tariffs would continue to be recoverable under the RTO's tariff. *See* Order 1000-A, P 490 (while Order 1000 does not require an incumbent to construct a project selected and abandoned by an non-incumbent, the RTO tariff or membership agreement may allow the RTO to direct a TO member to construct a transmission facility under certain circumstances).

[29] Significantly, an incumbent transmission developer/provider is defined as "an entity that develops a transmission project within its own retail distribution service territory or footprint," and a "'nonincumbent transmission developer' is any entity that is not an incumbent transmission developer/provider." Order 1000-A, P 416 (citing Order 1000, PP 225, 253 n.231). Thus, a nonincumbent transmission developer would include an incumbent proposing to develop a project outside its footprint.

subsidies are likely to drive up the total cost of transmission, defeating Order 1000's purpose of incenting more efficient and cost-effective solutions. At the June 28 Technical Conference, Southwest Power Pool, Inc.'s ("SPP") general counsel described SPP's recently completed competitive process, in which eleven competitive developers collectively spent between 3.3 million – 4.4 million dollars to produce competitive bids for a project estimated to cost $8.3 million.[30] Allowing unsuccessful bidders to recover their development costs from captive ratepayers would thus increase the total cost of that project by up to 50 percent.

Ratepayer subsidies to unsuccessful bidders would encourage bidders to incur development costs, even if they would far exceed any potential consumer benefits from competition. Such subsidization should be eliminated, or at an absolute minimum capped, to avoid the unintended consequence of spawning a cottage industry of poorly designed bids.

If the Commission nevertheless continues to provide an opportunity for potential recovery of costs associated with unsuccessful bids, any such recovery should be made contingent on the successful award and commencement of service of one or more future projects that have been selected for regional cost allocation through a process where those deferred unsuccessful bidder costs have been fully disclosed and considered. The Commission has allowed non-incumbent developers, in the context of obtaining advance

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[30] Paul Suskie, Southwest Power Pool, Prepared Statement for the Competitive Transmission Development Technical Conference, June 27–28, 2016, at 2, Docket No. AD16-18-000 (June 30, 2016), eLibrary No. 20160630-4036 ("Prepared Statement of Paul Suskie"). *See also* Tech. Conf. Tr. June 28 at 185:10–20 (Paul Suskie, Southwest Power Pool). Of the estimated 4.0 million – 5.0 million in SPP and developer costs, approximately 3.3 million – 4.4 million was spent by competing developers, while over $500,000 was spent by SPP to administer the process and evaluate the developer submissions. Prepared Statement of Paul Suskie at 2. After the selection process was completed, the project was cancelled. *See* footnote 41 below.

approval of formula rates and hypothetical capital structures, to create a regulatory asset to enable the developer to justify recovery of pre-award development costs associated with prior unsuccessful bids when that developer is awarded and puts in service another project.[31] To the extent a competitive developer wishes to pursue the regulatory asset treatment for unsuccessful bids costs, it should be required to disclose the amount of that additional potential cost recovery in its bids for future projects; to do otherwise would understate the real costs to be recovered from consumers if its future bid is accepted (because the developer intends to include that regulatory asset as part of the costs it recovers for any projects for which the developer is selected). Comparable treatment should be required for unsuccessful bid costs of incumbent TOs/TPs and their affiliates that choose to compete in the Order 1000 project selection process.

4. *Which entities should monitor, verify, and/or enforce compliance with cost containment provisions of selected transmission facilities? What are effective ways for them to do so and what are the advantages and disadvantages of different approaches?*

Comments: The Commission should require that any cost containment provisions associated with projects selected as part of the Order 1000 planning process be carried over from the developer's bid into the filed rate as a cap on the rates the developer may lawfully charge. Such limits should not only be recognized as terms mutually agreed upon by the developer and the RTO (with the expectation that the parties would abide by them), but also treated as elements of the filed rate that restrict the amounts the developer may seek to recover through its rate (either formula or stated).[32] Thus, the

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[31] *See* footnote 27.

[32] Compare *NextEra Energy Transmission West, LLC*, 154 FERC ¶ 61,009, P 75 n.129 (2016) (declining to provide the requested confirmation of the California Independent System Operator's understanding that the cost containment provisions will serve to limit the amounts that may be recovered through the developer's formula rate, but noting NextEra Energy Transmission West's response in which it agreed not to seek to

Commission should enforce these caps in the same way it enforces other aspects of a filed rate—i.e., on its own motion (through audits, etc.) and in response to complaints by RTOs or those subject to paying the costs (customers, state commissions/consumer advocates on behalf of retail ratepayers, other transmission owners in an RTO, transmission providers in non-RTO regions).

In addition, the Commission must fulfill its obligations to ensure that rates are not only consistent with the agreed upon cost containment provisions, but are just and reasonable under FPA Sections 205 and 206.

III. PANEL THREE: TRANSMISSION INCENTIVES AND COMPETITIVE TRANSMISSION DEVELOPMENT PROCESSES

1. *Should the Commission pre-approve any or all of the following incentives for transmission facilities selected in a regional transmission plan for purposes of cost allocation through competitive transmission development processes: 100 percent construction work in progress in rate base; regulatory asset treatment; or recovery of 100 percent of the cost of abandoned facilities?*

Comments: The Commission should adhere to its long-standing rule and policy requiring incentive rates to be proposed and reviewed on a case-by-case basis and subject to a demonstration as to the costs actually incurred. The Commission began Order 679, which implements FPA Section 219, by stating that "the Rule does not grant incentives to any public utility but instead permits an applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of Section 219." Order 679, P 2. It continued that it "will permit incentives only if the incentive package as a whole results in a just and reasonable rate." *Id.* The Commission reaffirmed this aspect of its policy on incentives in 2012, stating in its 2012 Policy Statement that "the Commission will continue to require applicants

recover any costs above the relevant caps).

seeking incentives to demonstrate how the total package of incentives requested is tailored to address demonstrable risks and challenges." 2012 Policy Statement, P 10. Requiring case-by-case consideration of incentives is thus consistent with Section 219 of the FPA, which authorizes incentive rates for transmission investment, but also provides that "[a]ll rates approved under the rules adopted pursuant to this section, including any revisions to the rules, are subject to the requirements of [Sections 205 and 206] that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential." 16 U.S.C. § 824s(d).

Continued case-by-case review should not be a major burden in most cases. Order 679 establishes a rebuttable presumption that a project included in a regional plan satisfies FPA Section 219's requirements that the facilities either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. *See* 18 C.F.R. §§ 35.35(d), 35.35(i)(i). Projects selected for regional cost allocation pursuant to an Order 1000-compliant process warrant the same presumption; and for projects subject to the presumption, applicants need only demonstrate the nexus between the requested incentive and investment. That requirement should not be an undue burden with regard to incentives designed to reduce risks and which are neutral to ratepayers (at least over the long term)—i.e., 100 percent construction work in progress in rate base, and regulatory asset treatment of development costs.

For the third type of incentive identified in the Commission's question—recovery of 100 percent of the cost of abandoned facilities—case-by-case evaluation is important to protect consumers from exposure to excessive and unwarranted costs. Order 1000-A explicitly reaffirmed that the Commission would continue to grant 100 percent abandoned plant cost recovery only on a case-by-case basis. Order 1000-A, P 489; *see also Tampa Elec. Co.*, 148 FERC ¶ 61,172, PP 431-32 (2014). Indeed, based on particular facts and circumstances, the Commission recently rejected the abandoned plant incentive for a project designated as a market efficiency project through the PJM Interconnection L.L.C. ("PJM") planning process, finding an insufficient demonstration that the incentive addressed demonstrable risks specific to the project.[33]

Case-by-case evaluation is also essential to ensure achievement of the 2012 Policy Statement's requirement that the overall package of incentives be evaluated for justness and reasonableness. It also facilitates maintenance of the conditions the Commission has placed on receipt of various incentives in Order 679 and its case-by-case orders. For example, regulatory asset treatment of prudent pre-commercial costs should be allowed only with recovery in rate base, subject to a demonstration in a future Section 205 filing of their justness and reasonableness.[34] Similarly, authorization to recover 100 percent of abandoned plant costs is subject to a demonstration of the justness and reasonableness of the abandoned transmission facilities costs in a separate Section 205 filing.[35] Further, actual recovery of 100 percent CWIP in rate base is subject to review under Sections 205 and 206.[36]

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[33] *PJM Interconnection L.L.C.*, 155 FERC ¶ 61,304, P 24 (2016).

[34] *See* Order 679, P 178; *Xcel Energy Southwest Transmission Co., LLC*, 149 FERC 61,182, P 35 (2014); *DesertLink, LLC*, 156 FERC 61,118, P 23 (2016).

[35] *See* Order 679, P 166; *DesertLink, LLC*, 156 FERC 61,118, P 29 & n.56 (citing Order 679, PP 165-66).

[36] Order 679, PP 117-18. *See, e.g., Desert Southwest Power, LLC*, 135 FERC ¶ 61,143, P 67 (2011) ("Our acceptance of Desert Southwest's request to recover 100 percent of CWIP in rate base is conditioned upon Desert Southwest's demonstration in a future FPA section 205 filing that its costs are prudent and result in a just and reasonable rate." (citing Order 679, P 118)).

If, despite TAPS' comments, the Commission moves forward to considering generic preapproval of certain incentives, it must do so in a way that maintains the requirements of Order 679 and the 2012 Policy Statement that the preapproved incentives be considered as part of the total incentive package to determine their justness and reasonableness. Thus, they should not be taken for granted, but rather must still be factored into the full package of incentives for purposes of assessing whether cost-increasing incentives (e.g., ROE) are merited. In addition, the specific conditions on those incentives need to be maintained.

2. *If there are benefits to customers from risk mitigation measures that transmission developers use in competitive transmission development processes, should the Commission revise its incentive policy to encourage similar risk mitigation measures that may provide customer benefits for transmission projects that are not subject to a competitive transmission development process? If so, what risk mitigation measures should the Commission encourage through application of the incentive policy?*

Comments: There is no need to change the 2012 Policy Statement. The 2012 Policy Statement, P 24 & n.33, rightly recognizes joint ownership as a risk mitigation measure that should be considered in awarding ROE incentives. This risk reduction measure is being used by some competitive developers,[37] but is already available both to developers participating in competitive development processes, and for projects developed outside those processes.[38]

This question seems to be focused on whether other risk mitigation measures used in the competitive process—presumably the variety of cost containment measures

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[37] For example, GridLiance, whose mission is to jointly plan, develop, own, and operate transmission projects with public power entities, has bid into ROE competitive transmission processes. GridLiance GP, LLC, *About* (last visited Sept. 28, 2016), http://www.gridliance.com/about/.

[38] *See* TAPS, *Inclusive Joint Transmission Ownership Arrangements: An Effective Means to Getting Needed Transmission Sited and Built* (2012), http://www.tapsgroup.org/wp-content/uploads/2013/01/TAPS-Joint-Ownership-White-Paper.pdf; TAPS, *Effective Solutions for Getting Needed Transmission Built at Reasonable Cost* (June 2004), http://www.tapsgroup.org/wp-content/uploads/2013/01/effectivesolutions.pdf.

discussed at the Technical Conference—should be encouraged for projects *not* subject to Order 1000 competitive transmission development processes via the award of ROE incentives. TAPS supports efforts to avoid excessive transmission rates by controlling the cost of all new transmission—not just transmission competitively developed. However, we strongly urge the Commission *not* to reward incumbent TOs and TPs for applying so-called "cost containment measures" to projects not covered by the Order 1000 competitive development process.[39]

TAPS sees no realistic potential for consumer benefits from rewarding such measures offered by an incumbent on a project for which it is not subject to any competition. Indeed, if such incentives were allowed, they would likely increase, rather than decrease, costs to consumers. Where the facts are fully within the incumbent's control and there is no competition, the availability of an incentive for not exceeding the "cost-contained" commitment would likely simply raise the cost containment commitment to a level the incumbent was sure to beat. As a result, consumers would be subjected to rates above cost-of-service.

Thus, there is no need to revise the 2012 Policy Statement to provide additional incentives for incumbents to include measures ostensibly containing costs on projects not subject to Order 1000 competitive processes. Indeed, cost containment measures do not merit new incentives under any circumstances. *See* Panel 3, Questions 3 and 4 below.

3. *In light of the emphasis that Order No. 1000 places on regional transmission planning, do the risks and challenges of a particular transmission project remain an appropriate focal point for incentives requested pursuant to Federal Power Act section 219? If not, what are the attributes that warrant incentives?*

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[39] If the Commission reopens the 2012 Policy Statement and Order 679, TAPS asks that the Commission reconsider whether the 50-basis point RTO adder is still warranted. *See* Peggy Bernardy, California Department of Water Resources, Tech. Conf. Tr. June 28 at 31:9–21.

Comments: The 2012 Policy Statement's focus on the risk and challenges of particular projects is the appropriate focal point for incentives pursuant to FPA Section 219. No change in focus is warranted.

Increased incentives are not needed to foster competition, as confirmed by LS Power,[40] as well as the high level of interest expressed by would-be developers in the Order 1000 processes to date. As a matter of common sense, if many competitors are voluntarily vying for the right to build a transmission project, there is clearly no need to grant additional incentives as an inducement.[41] The opportunity to receive assured cost recovery (including a Commission-determined ROE, except to the extent contained by commitments) is ample incentive to create and maintain developer interest. The regional transmission planning process, which is funded by load, combined with the *ex ante* cost allocation methodology required by Order 1000, decreases the financial risk associated

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[40] Lawrence Willick, LS Power, Tech. Conf. Tr. June 28 at 3:16–22 ("We find transmission to be an attractive investment under traditional cost and service rate regulation. We find it attractive enough to be aggressively competing, taking on additional risk, providing ratepayer benefits through mechanisms like caps and we do that in order to earn the right to undertake a cost of service investment opportunity."); Edward D. Tatum, Jr., American Municipal Power, Introductory Comments for the Competitive Transmission Development Technical Conference, June 27–28, 2016, at 1-2, Docket No. AD16-18-000 (June 30, 2016), eLibrary No. 20160630-4013 ("Introductory Comments of Edward Tatum") ("[R]ecent history has shown that rate incentives are not really necessary to encourage transmission investment. EEI correctly points out that transmission investment has been on the upswing over the last several years, for a number of reasons having nothing to do with incentives. In fact, what we've seen in recent years is that a number of companies have pulled money out of merchant generation activities, where their returns were uncertain, and redeployed capital toward their regulated business sectors, especially transmission. The reason is that these companies view FERC-regulated transmission service as providing a stable and relatively attractive return on investment.").

[41] In SPP, for example, eleven developers competed for a project estimated to cost $16.8 million, resulting in proposals from $8 million to $17 million. *See* SPP, Request for Proposal, RFP # SPP-RFP-000001 (RFP Issued Date: May 5, 2015), https://www.spp.org/documents/28843/spp-rfp-000001_website%20watermarked%20posting%20version_regdateupdate080315.pdf; SPP, Industry Expert Panel Recommendation Report at 4, RFP-000001 (Walkemeyer – North Liberal 115kV) (April 12, 2016) https://www.spp.org/documents/37708/iep%20recommendation%20report%20with%20process%20and%20appendix%20public%20redacted%20041216_redacted.pdf. Ultimately, the project was canceled based on reassessment of need. Tom Kleckner, *SPP Cancels First Competitive TX Project, Citing Falling Demand Projections*, RTO Insider (July 18, 2016), https://www.rtoinsider.com/spp-ferc-order-1000-transmission-demand-projections-28978/.

with non-incumbent transmission development. Few investment opportunities provide that degree of certainty.

Finally, the 2012 Policy Statement's objective of tailoring incentives to addressing the unique risks, if any, posed by the particular project is made all the more appropriate by the Order 1000 process for selection of the more cost-effective and efficient projects that yield reliability, economic, or public policy benefits. As noted in response to Panel 3, Question 1, Order 679 establishes a rebuttable presumption that projects included in a regional plan satisfy FPA Section 219's requirement that the facilities for which incentives are sought either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. Projects selected in the Order 1000 process should qualify for that presumption. However, satisfaction of Order 679's nexus requirement—which involves an evaluation of the specific risks of the project—remains necessary and appropriate.

4. *What, if any, changes are needed to the framework the Commission uses to evaluate return on equity adders and other transmission incentives for transmission projects that use cost containment provisions?*

The Commission should not modify the 2012 Policy Statement to allow ROE and other incentives for cost containment measures. As discussed in response to Panel 3, Question 2, such incentives are inappropriate for incumbent projects that are not subject to any competition. Nor are they necessary or appropriate to incent developers to elect to submit a bid with cost containment measures in order to enhance its chance of selection. As discussed in response to Panel 3, Question 3, the opportunity to secure an assured cost recovery (including a FERC-regulated return, except to the extent limited by cost containment measures) is itself sufficient reward without adding more. It would be contrary to Order 1000's objective of providing savings to consumers, to reduce those benefits by granting ROE incentives to compensate the developer for risks it is in the best position to evaluate and address through its voluntary bid.

The uniform opposition of developers speaking at the Technical Conference to the suggestion that cost containment measures be standardized highlights the unreasonableness of granting incentives for bids that include such measures. Absent Commission standardization of fully effective and inclusive cost containment provisions (as TAPS requests in response to Panel 1, Question 3), the term "cost containment" will cover a range of provisions, with loopholes and exemptions limited only by the creativity of the developer and its experts. Even robust competition may be insufficient to discipline the fine print. As a result, so-called cost containment measures may well prove more apparent than real, leaving consumers shouldering significant risks notwithstanding purported cost containment. Adding incentive ROEs to reward developers for pseudo-containment measures makes it more likely that consumers will be subjected to above-cost rates.

Thus, the Commission should take developer requests for incentives for voluntary cost containment bids with a huge grain of salt; no new ROE incentive is warranted. In any case, the Commission should not allow any incentive that was not expressly included in bids submitted for evaluation in the Order 1000 process. In addition, as discussed in response to Panel 5, Question 6, no change in the Commission's DCF methodology is warranted to take account of the claimed risks associated with cost containment bids.

5. *Order No. 1000 requires public utility transmission providers in regions to have an ex ante cost allocation method for transmission facilities selected in the regional transmission plan for purposes of cost allocation. To what extent does the ex ante cost allocation method reduce risks to transmission developers?*

<u>Comments</u>: *Ex ante* cost allocation greatly reduces risk by ensuring cost recovery. That was an express purpose of requiring *ex ante* cost allocation. *See* Order 1000, P 561 ("By imposing the cost allocation requirements adopted here, the Commission seeks to enhance certainty for developers of potential transmission facilities by identifying, up front, the cost allocation implications of selecting a transmission facility in the regional transmission plan for purposes of cost allocation."). Few investment opportunities come with assurance of full cost recovery through formula rates, with a FERC-regulated return, including RTO participation incentives and the potential for project specific incentives, if warranted.[42] There is simply no basis to believe that additional incentives are necessary to attract needed capital for transmission projects.

6. *Transmission developers face at least two types of risks: risk associated with participation in the transmission planning processes and risk associated with developing a transmission project. The Commission's current incentive policies focus on the latter. Please comment on risks associated with participation in the transmission planning processes and indicate what, if any, changes to the planning processes could mitigate the risk.*

<u>Comments</u>: A key purpose of Order 1000 (PP 289, 253, 284) is to reduce transmission costs to consumers by allowing competition from non-incumbent developers, so we shouldn't eliminate the competitive risk of the transmission planning process. As discussed above, increased incentives are *not* required to foster such competition; the regional transmission planning process, which is funded by load, and *ex ante* cost allocation required by Order 1000, significantly decrease the financial risk associated with non-incumbent transmission development.

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[42] Compare, for example, the hurdles a merchant transmission developer faces in securing subscriptions.

In RTO areas, *if* the regional planning process is robust,[43] using a competitive solicitation model—rather than a sponsorship model—can both make competition more transparent and effective, and mitigate the risks for competitive transmission developers from participating in transmission planning processes. Under the competitive solicitation model, developers submit bids for constructing and owning projects that have already been identified and well-defined (through earlier stages of the Order 1000 process) as the more cost-effective and efficient solution to a need. Holding a focused competitive solicitation at this later stage of the process provides participating developers with greater certainty as to the project to be developed, greater ability to assess their likelihood of winning, and more assurance that a winner will in fact be selected and the project actually constructed. To maximize consumer benefits, such competitive solicitation should give significant weight (e.g., 85–90 percent) to cost in qualifying bids that satisfy the project specifications, particularly if bids include standardized, effective, and fully inclusive cost containment provisions (*see* Panel 1, Question 3). Focusing evaluation in this manner would also provide developers with greater certainty as to how their bids would be assessed. Competitive solicitation procedures could also provide for bonus points for a competitor whose designs/ideas are adopted in earlier stages of the planning process and subsequently bid out, increasing the likelihood that competitor would win the competitive solicitation.

The competitive solicitation model, however, isn't the best choice in all regions. As discussed in Panel 5, Question 5, the sponsorship model works better for non-RTO

[43] Note, however, that the Commission recently issued a show cause order, identifying concerns that the local planning process used by PJM TOs was not compliant with Order 890, therefore not compliant with Order 1000. *Monongahela Power Co.*, 156 FERC ¶ 61,134 (2016).

areas. Individual TPs in non-RTO areas typically do not focus on developing projects outside their footprint; non-incumbents are therefore more likely to see and propose regional solutions that cross TP borders. To get the benefits of non-incumbent planning perspectives, the sponsorship model should be used in those areas.

In both RTO and non-RTO areas, we should be looking for incremental improvements to eliminate unnecessary risk as we gain more experience. Maximizing transparency as to the bids submitted and how they are evaluated, as discussed in response to Panel 1, Question 2, would be a major step forward in this direction.

7. *Do public utility transmission providers in regions consider that a transmission developer may request and be awarded transmission incentives when evaluating transmission proposals and, if so, how? For example, how would public utility transmission providers in regions consider a proposal with a potential transmission incentive given that the incentive might or might not be granted? Should a competitive transmission development process clearly state whether, and, if so, how incentives should be part of a developer's proposal and how requests and grants of such incentives will be evaluated by the public utility transmission providers in the region? Is there an optimal time for submission of incentive requests to the Commission and for Commission decisions upon them?*

Comments: A competitive transmission development process should clearly state whether, and, if so, how incentives will be included in each developer's proposal and how requests and grants of such incentives will be evaluated by the public utility TPs in the region. Even if a bid does not include ROE or capital structure, the developer's position on whether it reserves the right to seek incentives and, if so, which ones (and in what amounts), should be spelled out in the bid so it can be considered in the evaluation process. Otherwise, the Commission is inviting a "bait and switch" game that has no place in a process intended to benefit consumers.

IV. PANEL FOUR: INTERREGIONAL TRANSMISSION COORDINATION ISSUES

1. *What factors have contributed to the lack of development of interregional transmission facilities (i.e., a transmission facility that is located in two or more transmission planning regions)? Are there actions the Commission could take to facilitate such development?*

2. *What would be the advantages and disadvantages to the use of common models and assumptions by public utility transmission providers in regions in their interregional coordination processes? Are there problems that such an approach would solve or create? If such common models and assumptions could be developed, how should they be developed and by which entity or entities?*
3. *Should the Commission revisit Order No. 1000's requirement that an interregional transmission facility be selected in the regional transmission plan of all transmission planning regions where the facility will be located before it is eligible for interregional cost allocation? Why or why not?*
4. *What reforms, if any, could the Commission adopt to facilitate the identification of shared interregional transmission needs?*
5. *Do interregional cost allocation methods accepted by the Commission, such as the "avoided cost only" method, impede interregional transmission coordination? [footnote omitted] If so, are there alternative cost allocation methods that could better facilitate interregional transmission development? Would those methods be consistent with interregional transmission coordination processes or would the interregional transmission coordination processes need to change to accommodate such alternative cost allocation methods?*

Comments: It is premature for the Commission to consider generically mandating significant changes to the Order 1000 interregional coordination requirements. The interregional coordination efforts required by Order 1000 have barely begun—there has not even been one full cycle in many places. It is simply too soon to assess whether Order 1000's interregional coordination requirements strike the right balance, or whether additional reforms should be considered. TAPS urges the Commission to wait for completion of one to two interregional planning cycles before considering further reforms.

For example, as recognized in Question 3, Order 1000 requires that an interregional facility be selected in the regional transmission plan of all transmission planning regions where the facility will be located before it is eligible for interregional cost allocation. While that requirement could operate to limit interregional facilities, it is important to assuring that both regions "buy in" to all interregional projects. It also provides protection against excessive construction.

Similarly, as recognized in Question 5, while Order 1000 does not allow exclusive reliance on avoided cost in regional cost allocation, the Commission has allowed an avoided-cost-only cost allocation methodology for interregional projects.[44] As a result, interregional projects cannot be approved unless each region has a project in its regional plan that will be avoided as a result of the interregional facility. While this may unduly limit interregional facilities—because regions do not plan for interregional needs, there may be nothing in one or both regional plans to displace—the requirement may provide important safeguards against excessive construction and may help build trust, recognizing that the institutions needed to perform effective interregional joint planning often don't exist.

With particular reference to Question 2, efforts are underway in some regions to develop either common models, or regional models that interact better with neighboring regional models at their seams.[45] The Commission should give these efforts time to develop and learn from the results before generically considering major modeling changes that could disrupt ongoing local and regional planning efforts.

In short, interregional coordination is in its infancy. While further reforms (e.g., joint planning) may be required for this process to produce the interregional facilities the Commission hopes to encourage, both the need for change and the needed changes may be clearer after we have had more experience (1-2 cycles) with the new interregional coordination processes.

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[44] Question 5 cites *Midcontinent Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,045, PP 176-180 (2015) (subsequent history omitted) in that regard.

[45] *See, e.g.,* ISO-New England/NYISO/PJM - Joint ISO/RTO Planning Committee and its open stakeholder group, Interregional Planning Stakeholder Advisory Committee, http://www.pjm.com/committees-and-groups/stakeholder-meetings/ipsac-ny-ne.aspx; Eastern Interconnection Planning Collaborative, http://www.eipconline.com/home.html. The Commission has also directed that PJM and MISO explore potential use of a joint model with the same assumptions and criteria in each of their regional planning processes. *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc. & PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,058, PP 88-90, 92 (2016).

V. PANEL FIVE: REGIONAL TRANSMISSION PLANNING AND OTHER TRANSMISSION DEVELOPMENT ISSUES

1. *To maximize the benefits of competition, should the Commission broaden or narrow the type of transmission facilities that must be selected through competitive transmission development processes? If so, how?*

Comments: The Commission has allowed a range of thresholds (voltage, length, and cost) for projects eligible for selection in Order 1000 plans for regional cost allocation, thereby limiting the projects open to Order 1000 competitive processes. In some early competitions, the cost of the competitive process may have outweighed any potential cost savings.[46] However, increasing thresholds for competitive development projects could discourage creative, low-cost solutions. [47]

The Commission should remain open to consideration of case-by-case requests to adjust (by broadening or narrowing) the types of transmission facilities that must be selected through competitive transmission development processes, subject to appropriate reporting requirements.[48] However, it should not at this time generically narrow or expand the range of transmission projects. The industry is still gaining experience with Order 1000 competitive transmission development processes, and thresholds vary from region to region. Over time, competitive transmission development processes should

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[46] *See* discussion above at 20 and footnote 30.

[47] *See N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc. & PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,058, PP 129, 131, where the Commission found certain provisions of the MISO-PJM Joint Operating Agreement and MISO tariff unjust and unreasonable because cost and voltage thresholds excluded from consideration certain projects in the MISO-PJM interregional transmission planning process that benefit both regions. It required MISO to reduce its minimum voltage threshold for interregional economic projects from 345 kV to 100 kV, and eliminate the $5 million threshold for such projects. In doing so, the Commission relied on the low hanging fruit identified for improving the PJM/MISO seam ("Quick Hits" projects). *Id.* PP 108, 131-32.

[48] *See, e.g.*, *PJM Interconnection, L.L.C.*, 156 FERC ¶ 61,132 (2016), in which the Commission granted (with modification) PJM's request to exempt certain below-200 kV facilities from the competitive process, conditioned on additional transparency requirements.

work better and more efficiently, decreasing transactions costs and delay. After we have more experience, the Commission may want to consider revisiting the scope of competitive processes.

2. *Has the introduction of competition into the regional transmission planning processes led public utility transmission providers to focus more on developing local transmission facilities or other transmission facilities not subject to competitive transmission development processes?*

Comments: Although TAPS has not compiled detailed metrics, our impression is that TOs are focusing on developing local projects that are not subject to the RTO's planning process and competition. This is due in part to changing definitions. For example, MISO's decision to eliminate regional cost allocation for Baseline Reliability Projects ("BRPs"), contemporaneous with submitting its Order 1000 compliance, made BRPs "local" rather than "regional" for purposes of Order 1000.[49]

Data from PJM likewise indicate that there has been a large increase in planned "Supplemental" projects that are local and ineligible for selection in PJM's regional plans for regional cost allocation, and a shift away from "Baseline" projects (which are eligible for regional cost allocation).[50] Not only are such Supplemental projects exempt from

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[49] *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 FERC ¶ 61,215, PP 20, 518 (2013) (subsequent history omitted).

[50] Although data limitations and the inherent lumpiness of transmission investment make it difficult to draw definitive conclusions, data on constructed and planned projects in PJM suggest a shift toward local projects not eligible for regional cost allocation. Planned Supplemental projects (which are locally allocated) appear to have increased dramatically after the issuance of Order 1000. Based on PJM's spreadsheets for Supplemental projects, the estimated value of all Supplemental projects planned between 2005-2011 (and not subsequently cancelled) totaled $4.9 billion. In contrast, the total value of the Supplemental projects planned (and not cancelled) since 2012—a shorter period—is approximately $12.9 billion. *See* three "Transmission Owner Initiated/Supplemental" Spreadsheets available at http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx; each filtered for Initial_TEAC_DATE.

Meanwhile, the data on Baseline project investment (which is regionally allocated) show the opposite pattern. According to PJM's spreadsheets, the estimated value of all Baseline projects planned between 2005-2011 (and not subsequently cancelled) totaled about $15.5 billion. The total value of the Baseline projects planned (and not cancelled) since 2012 fell to about $10.3 billion. *See* three "Transmission Owner Initiated/Supplemental" Spreadsheets available at http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx; each filtered for Initial_TEAC_DATE.

Order 1000 competitive processes, the Commission recently issued a show cause order because of concerns that Transmission Owner local planning processes in PJM, as implemented, do not fully comply with Order 890's planning requirements.[51]

3. *Are there other competitive approaches compared to the existing competitive transmission development processes that could potentially reduce the time and cost to conduct the process, or the risk of litigation over proposal selection, but still benefit consumers? If so, what are the strengths and weaknesses of such approaches and could they be used in transmission planning regions in specified circumstances, for example, for transmission projects needed in the near-term to address reliability needs, in conjunction with existing competitive transmission development processes?*

Comments: See responses to Panel 3, Question 6 and Panel 5, Question 5.

4. *What types of information (please be specific) could be used to measure the impact of the Order No. 1000 reforms on transmission development? For example, what information could be used to evaluate whether the more efficient or cost-effective transmission facilities are being selected within and between transmission planning regions? How should that information be tracked and reported or posted? Should common metrics be developed for evaluation of the information?*

Comments: TAPS has long supported development of a grid capable of supporting robust wholesale competition. At the same time, as transmission dependent utilities, we bear—and care about controlling—transmission costs. Order 1000 shares both of these goals. Its purpose is not simply to build more transmission, regardless of expense or benefits; instead, it seeks to foster the development of transmission that is efficient and cost-effective in meeting the needs of load-serving entities ("LSEs").

To determine whether these goals are being achieved, the Commission must look beyond simple counts of the number of non-incumbent proposals submitted in regional and interregional processes, and the number of transmission projects selected for regional cost allocation. Even if averaged over multiple years to account for the inherent

Planned Baseline project investment, therefore, appears to have been almost triple the level of planned Supplemental project investment over the 2005-2011 regional planning years. In contrast, the value of Baseline projects planned after Order 1000 is *less* than the value of Supplemental projects planned during that same period ($10.3 billion of Baseline projects versus $12.9 billion of Supplemental projects). *See* Spreadsheets available at http://pjm.com/planning/rtep-upgrades-status/construct-status.aspx.

[51] *Monongahela Power Co*., 156 FERC ¶ 61,134 (2016).

lumpiness of major transmission investment, these types of descriptive statistics do not capture whether, and to what extent, new projects meet the reasonable needs of LSEs, consistent with FPA Section 217(b)(4). Low counts, for example, may be the result of a robust existing transmission network, or high thresholds for eligibility for regional cost allocation—not the region's failure to build needed projects. High counts may be the product of excessive construction or a region's low thresholds for eligibility for regional cost allocation, rather than an indication that the region is doing a good job of meeting LSE needs.

The key, instead, is to develop metrics for assessing whether appropriate levels of transmission investment exist, and to track those metrics over time. For RTO areas, measuring congestion—nodal pricing differentials—seems like a reasonable focus. For regions without organized markets, FERC Staff indicated in its March 2016 Transmission Metrics report that EQR data could be used to understand pricing trends in bilateral markets, and to develop an analogous price-based transmission infrastructure metric for non-RTO regions.[52]

For paths between Balancing Authorities—typically between individual transmission providers in non-RTO regions, and for paths between regions—we suggest that the Commission consider a variety of metrics, including the following:

- A transmission utilization factor, as measured by the ratio of Available Transfer Capability ("ATC") to Total Transfer Capability ("TTC").
- ATC availability, as measured by the percentage of time that firm ATC is zero on an ATC path.

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[52] Federal Energy Regulatory Commission, *Transmission Metrics: Initial Results – Staff Report* at 14, Docket No. AD15-12-000 (Mar. 17, 2016), eLibrary No. 20160317-3068.

To make these specific proposed metrics more manageable, TAPS recommends limiting them to ATC paths between Balancing Authorities that have loads greater than 1,000 MW.[53]

In addition, the Commission should develop metrics to track the actual cost of transmission facilities selected in Order 1000 processes, as compared to: (1) the cost estimates used to evaluate the transmission solutions included in the regional plan; and (2) the estimates submitted by developers that are used to select the winning projects and developers. All too often, actual costs to consumers far exceed the estimated costs of proposed transmission. Particularly since Order 1000 selection processes rely on a comparison of costs and benefits, it is important to understand whether, and to what extent, the cost estimates provided at various stages are accurate. This information will help regions and the Commission better understand the factors that drive variation from estimated cost, improve Order 1000 benefit-cost analysis and project selection methodologies, and evaluate the benefits of cost containment provisions.

5. *How do the sponsorship model and competitive bidding model, respectively, and variations on these models, capture the benefits of competition, such as increased innovation and selection of the more efficient or cost-effective transmission facilities? What are the positive features and drawbacks of each model? How can their drawbacks be addressed?*

<u>Comments</u>: Order 1000 allowed regional flexibility in the models to be used for selecting developers for projects subject to regional cost allocation. Two different

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[53] For such interfaces, the Commission might also consider tracking: (1) transmission requests denied, as measured by frequency or total volume; or (2) percentage of transmission requests approved. These metrics, however, may be less reliable than the transmission utilization and ATC availability metrics discussed in the main text, because customers often stop requesting service over constrained interfaces—despite persistent price differentials—if they expect all such requests will be denied. *See, e.g.*, *Transmission Metrics: Initial Results – Staff Report* at 14 (noting that if transmission operators in a region use very conservative ATC assumptions in deciding whether or not to approve transmission service requests, customers may stop requesting transmission service, despite price differentials that would otherwise lead them to seek less expensive supplies).

approaches have emerged: (i) the "competitive solicitation model" (solicit proposals for a well-defined project that has been first determined to be the best solution to a transmission need, such as the construction of a new transmission line to be built on a pre-determined route and to predetermined construction standards); or (ii) the "sponsorship model" (solicit various design proposals that provide solutions to a defined transmission need).

As discussed in response to Panel 3, Question 6, for RTO areas that have a robust planning process for developing and selecting solutions to transmission needs, TAPS prefers the competitive solicitation model, which it believes will provide the greatest benefits for consumers. As also discussed above, cost should also be the dominant selection criterion in those RTO competitive solicitation processes. RTOs could be given the option of considering non-cost factors on a limited basis (e.g., whether the competitive developer proposed the design for the transmission solution for which bids are being solicited), perhaps weighted at up to 10 percent of 15 percent of the project score. Cost, however, should be weighted at 85–90 percent, assuming cost differences are non-trivial. This approach might not prevent the winning developer's bid from significantly exceeding just and reasonable cost-of-service rates,[54] but this focus on cost will make the selection process both less expensive to administer and more transparent and objective.

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[54] *See, e.g.*, Introductory Comments of Edward Tatum at 2, (noting that "cost containment provisions aren't a good deal for the consumer if the costs of developers' hedges, or even the impact on developers' borrowing costs, wind up being greater than the construction costs kept out of rates by operation of the cap.")

However, as also explained in response to Panel 3 Question 6, in non-RTO areas, the sponsorship model is better suited to identifying more efficient and cost-effective projects. Individual TPs in non-RTO areas typically do not focus on developing projects outside their footprint; non-incumbents are more likely to see and propose regional solutions that cross TP borders. It is therefore important to bring non-incumbent proposals into the process early, so that their alternative solutions can compete for selection in the regional plan. Waiting until the competitive solicitation stage may unduly limit the designs and solutions being considered.

In addition, in non-RTO areas that use the sponsorship model, it may be inappropriate for cost to be the dominant selection criterion. In the sponsorship model, competition among potential solutions to identified needs will necessarily be influenced by factors other than cost. It also is much more difficult to make an apples-to-apples comparison between competing proposals that may have very different configurations.

6. *Are changes to the Commission's current application of the Discounted Cash Flow (DCF) analysis needed to better accommodate nonincumbent transmission developers, in particular with respect to the identification of appropriate proxy groups? If so, what changes are necessary?*

Comments: At the Technical Conference, former Chairman Kelliher, appearing for the transmission-developing subsidiary of NextEra Energy, urged that transmission developer ROEs should be set using proxy groups that are "different," in some unspecified way, because "[i]f competitive entrants are different they have different risk profiles" from "operating incumbents."[55] Proxy groups used in setting transmission developers' regulated rates should be risk-comparable to the entity raising funds for project investment. However, existing Commission policy is already well-designed to

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[55] Joe Kelliher, NextEra Energy Transmission, LLC, Tech. Conf. Tr. June 28 at 25:10–22. *See also id.* at 26-28, 37-39.

identify risk-comparable proxy groups, and NextEra Energy's vague proposal for "different" proxy groups would do more harm than good. Four points compel this conclusion.

One, NextEra Energy's argument relies on a false premise. Under existing Commission policy, DCF proxy groups do not consist of "operating incumbents." The DCF methodology inherently requires that proxy companies be entities that issue publicly-traded stock, and DCF proxy companies therefore consist of holding-company-level entities—Alliant Energy Corp., not Wisconsin Power & Light; Duke Energy, not Duke Energy Florida; NextEra, not Florida Power & Light; and so forth. Entities that serve as DCF proxies under existing Commission policy typically hold diverse lines of business, commonly including merchant generation and/or non-incumbent transmission development, not only regulated "incumbent" activities. Consider the 41 proxy companies that were referenced in Opinion 531, which encompassed virtually the entire universe of U.S. electric utility holding company stocks as of 2013.[56] Of those 41 proxy companies, seven have been acquired or are presently in the process of being acquired, and therefore are no longer candidates to serve as DCF proxies; the other 34 remain extant as proxy candidates. Almost all of those potential proxies—31 of 34—have substantial generation risk exposure, typically including unregulated merchant operation through affiliated power producers. Only four of the 34 have divested their "incumbent transmission" ownership.

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[56] *Coakley v. Bangor Hydro-Electric Co.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014) ("Opinion 531"), *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *reh'g denied*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *pet. for review filed*, *Emera Me., f/k/a Bangor Hydro-Elec. Co., et al. v. FERC*, Nos. 15-1118, et al. (D.C. Cir. filed Apr. 30, 2015).

Table. DCF Proxy Entities and Selected Characteristics.[57]

Ticker	*Entity Name*	*Stock Defunct?*	*Substantially Generation-divested?*	*Substantially Transmission-divested?*
ALE	ALLETE, Inc.			
LNT	Alliant Energy Corp.			X
AEE	Ameren Corp.			
AEP	American Electric Power Co.			
AVA	Avista Corp.			
BKH	Black Hills Corp.			
CNP	CenterPoint Energy, Inc.		X	
CNL	Cleco Corp.	X		
CMS	CMS Energy Corp.			X
ED	Consolidated Edison, Inc.		X	
D	Dominion Resources, Inc.			
DTE	DTE Energy Co.			X
DUK	Duke Energy Corp.			
EIX	Edison International			
EE	El Paso Electric Co.			
EDE	Empire District Electric Co.	X		
FE	FirstEnergy Corp.			
GXP	Great Plains Energy Inc.			
HE	Hawaiian Electric Industries, Inc.			
IDA	IDACORP, Inc.			
TEG	Integrys Energy Group, Inc.	X		
NEE	NextEra Energy, Inc.			
NU/EE	Northeast Utilities/Eversource		X	
NWE	NorthWestern Corp.			
OGE	OGE Energy Corp.			
OTTR	Otter Tail Corp.			
POM	Pepco Holdings, Inc.	X		
PCG	PG&E Corp.			
PNW	Pinnacle West Capital Corp.			

[57] S&P Global Platts, *UDI Directory of Electric Power Producers and Distributors* (2015); Interstate Power & Light Co., FERC Financial Report Form No. 1 (Apr. 14, 2016), eLibrary No. 20160416-8030 (regarding Alliant Energy Corp.); *Algonquin Power & Utilities Corp. to Acquire The Empire District Electric Company in C$3.4 Billion (US$2.4 Billion) Transaction*, Business Wire (Feb. 9, 2016), http://www.businesswire.com/news/home/20160209006719/en/Algonquin-Power-Utilities-Corp.-Acquire-Empire-District; *Great Plains Energy to Acquire Westar Energy, Creating Long-Term Value for Shareholders and Cost Savings for Customers*, Westar Energy (May 31, 2016), http://www-wichita.westarenergy.com/content/about-us/news/2016-news-releases/great-plains-energy-to-acquire-westar-energy.

Ticker	*Entity Name*	*Stock Defunct?*	*Substantially Generation-divested?*	*Substantially Transmission-divested?*
POR	Portland General Electric Co.			
PPL	PPL Corp.			
PEG	Pub. Serv. Enterprise Grp.			
SCG	SCANA Corp.			
SRE	Sempra Energy			
SO	Southern Company			
TE	TECO Energy, Inc.	X		
UIL	UIL Holdings Corp.	X		
VVC	Vectren Corp.			
WR	Westar Energy, Inc.	X		
WEC	Wisconsin Energy Corp.			X
XEL	Xcel Energy, Inc.			

Thus, the fact that non-incumbent transmission developers may face a form of competition in some transmission development contests does not meaningfully differentiate them from the publicly-traded U.S. electric utility holding companies that currently serve as DCF proxy candidates; those holding companies face competition too.

Two, existing Commission policy already provides for the formation of risk-comparable proxy groups, by selecting from within the universe of publicly-traded holding-company-level firms, those with corporate credit ratings resembling the subject utility. Specifically, the Commission's standard methodology, as refined in Opinion 531, requires that all proxies' corporate credit ratings, as available from both Moody's and Standard & Poors, be within one ratings "notch" of the regulated entity at issue.[58] The Commission has explained that it relies on credit ratings as a good synoptic summary of the various factors that affect entities' risks. *See, e.g., Virginia Electric & Power Co.*,

[58] *See* Opinion 531, 147 FERC ¶ 61,234, PP 103-08.

123 FERC ¶ 61,098, P 62 (2008) ("It is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both financial and business risk."). Commonly, Moody's rates operating utility subsidiaries as less risky than their holding-company-level parents. Consequently, proxy groups used in setting operating utility ROEs will tend to reflect the safer end of the spectrum of parent-level stocks.[59] In contrast, if a competitive transmission developer is riskier than is typical of operating utility subsidiaries, then its credit rating will suffer accordingly, and the proxy group used to set its ROE will be selected from the riskier end of the spectrum of parent-level stocks. For example, whereas a parent-level stock rated Baa1 would not be a suitable proxy for a utility operating subsidiary rated A1, that rating would not disqualify such a parent from serving as a proxy for a competitive transmission developer rated Baa1. In this way, the proxy group used to set a transmission developer's ROE will reflect that developer's higher risk. Thus, existing Commission policy already provides a straightforward mechanism through which proxy group selection directly reflects variations in subject utility risk.

Three, many competitive transmission developers are subsidiaries of parent holding companies that also own operating service-area utilities, and conversely, many of the candidate holding-company-level proxies have established or are considering establishing affiliated transmission developers. For example, NextEra Energy Transmission is a wholly-owned indirect subsidiary of NextEra Energy, and has informed

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[59] For example, Moody's recently affirmed its credit rating for NextEra Energy, Inc. as "Baa1," and its ratings for NextEra subsidiary Florida Power & Light Company ("FPL") as "A1." *Moody's affirms NextEra Energy (Baa1 stable) on Oncor acquisition announcement*, Moody's Global Credit Research (July 29, 2016), https://www.moodys.com/research/Moodys-affirms-NextEra-Energy-Baa1-stable-on-Oncor-acquisition-announcement--PR_351579. NextEra's Baa1 rating currently makes it too risky to pass the "one notch" test to qualify as a proxy for use in setting FPL's ROE.

investors that it receives financial support from its parent.[60] American Electric Power Co. has formed transmission developer affiliates in multiple states; Ameren Corp. has formed "ATX" transmission developer subsidiaries for the SPP and MISO regions; Berkshire Hathaway Transmission is affiliated with MidAmerican Energy Co., and so on through the alphabet (Westar Energy, Inc. has formed Kanstar Transmission, LLC, and is participating with MidAmerican Energy Co.'s affiliate in the "Midwest Power Transmission Arkansas" joint venture). Where a transmission developer subsidiary issues its own bonds as its own financially distinct entity, it presumably will have its own bond rating that can be used to identify comparably risky parent-level stock issuers. (Where such a subsidiary does not have such an independent financial life, its cost of equity is that of the parent,[61] and the parent will have a bond rating of its own.) And where parent-level stock issuers own competitive transmission developers, their parent-level risk and growth prospects, and thus their DCF-indicated costs of equity, will reflect the risks and rewards of competitive transmission development.

Four, contentions that competitive transmission projects should receive a higher ROE because cost-contained bids increase project-specific risk should be rejected as "Lake Wobegon ratemaking," under which all rates are above average. The Commission has repeatedly rejected calls to reduce transmission-service ROEs so as to reflect that service's low risk relative to other services of the transmission-owning regulated entity, holding instead that returns should reflect the company-wide risk of the company that

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[60] *See* NextEra Energy Transmission, *Building tomorrow's energy infrastructure*, http://www.nexteraenergy.com/pdf/NEET-Trans-factsheet.pdf.

[61] *See, e.g., Transcon. Gas Pipe Line Corp.*, Opinion No. 414-A, 84 FERC ¶ 61,084, *reh'g denied*, Opinion No. 414-B, 85 FERC ¶ 61,323 (1998).

invests in transmission assets. *See, e.g., Boston Edison Co.*, 79 FERC ¶ 61,328, at 62,430 (1997) ("*Boston Edison*") (return is properly calculated on a company-wide basis, not on a customer-specific or contract-specific basis); *cf. Chehalis Power Generating, L.P.*, 123 FERC ¶ 61,038, P 170 (2008) (citing *Boston Edison* and applying it to debt costs). In fairness to customers, the Commission cannot reasonably turn around and increase ROEs when associated with an asset that is deemed to be relatively risky on a stand-alone basis, but which is owned by a company that, on an enterprise-wide basis, investors view as safe.

CONCLUSION

The Commission should take into account TAPS' comments as it considers actions to be taken on the important issues raised in its questions.

Respectfully submitted,

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