NITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Transmission Investment Through Pricing Reform	**)** **)**	**Docket No. RM11-26-000**

JOINT COMMENTS OF
THE AMERICAN FOREST & PAPER ASSOCIATION, THE AMERICAN PUBLIC POWER ASSOCIATION, THE CALIFORNIA MUNICIPAL UTILITIES ASSOCIATION, CALIFORNIA PUBLIC UTILITIES COMMISSION, CITY AND COUNTY OF SAN FRANCISCO, CONNECTICUT OFFICE OF CONSUMER COUNSEL, ELECTRICITY CONSUMERS RESOURCE COUNCIL, INDIANA UTILITY REGULATORY COMMISSION, MARYLAND OFFICE OF PEOPLE'S COUNSEL, MODESTO IRRIGATION DISTRICT, MONTANA PUBLIC SERVICE COMMISSION, THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES, NEW ENGLAND CONFERENCE OF PUBLIC UTILITIES COMMISSIONERS, NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION, NEW JERSEY BOARD OF PUBLIC UTILITIES, NEW JERSEY DIVISION OF RATE COUNSEL, NORTHERN CALIFORNIA POWER AGENCY, OFFICE OF THE NEVADA ATTORNEY GENERAL-BUREAU OF CONSUMER PROTECTION, OFFICE OF THE OHIO CONSUMERS' COUNSEL, OLD DOMINION ELECTRIC COOPERATIVE, ORGANIZATION OF MISO STATES, PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE, PUBLIC POWER COUNCIL, PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK, PUBLIC SERVICE COMMISSION OF WISCONSIN, SACRAMENTO MUNICIPAL UTILITY DISTRICT, SOUTH DAKOTA PUBLIC UTILITIES COMMISSION, STATE OF MAINE, OFFICE OF THE PUBLIC ADVOCATE, TRANSMISSION AGENCY OF NORTHERN CALIFORNIA, THE VERMONT DEPARTMENT OF PUBLIC SERVICE AND VERMONT PUBLIC SERVICE BOARD

In accordance with the Federal Energy Regulatory Commission's ("Commission") May 19, 2011 "Notice of Inquiry"[1] ("NOI") and its June 8, 2011 and August 12, 2011 "Notices Extending Comment Period" issued in the above-noted docket, an *ad hoc* coalition of state public utility commissions, state consumer advocates, public power systems, rural electric cooperatives, and end users, which are comprised of the American Forest & Paper Association, American Public Power Association, California Municipal Utilities Association, California

[1] 76 Fed. Reg. 30,869 (May 27, 2011).

Public Utilities Commission, City and County of San Francisco, Connecticut Office of Consumer Counsel, Electricity Consumers Resource Council, Indiana Utility Regulatory Commission, Maryland Office of People's Counsel, Modesto Irrigation District, Montana Public Service Commission, National Association of State Utility Consumer Advocates, New England Conference of Public Utilities Commissioners,[2] New Jersey Board of Public Utilities, New Jersey Division of Rate Counsel, Northern California Power Agency, Office of the Ohio Consumers' Counsel, Office of the Nevada Attorney General's Bureau of Consumer Protection, Old Dominion Electric Cooperative, Pennsylvania Office of Consumer Advocate, Public Power Council, Organization of MISO States,[3] Public Service Commission of the State of New York, Public Service Commission of Wisconsin, Sacramento Municipal Utility District, South Dakota Public Utilities Commission, State of Maine, Office of the Public Advocate, Transmission Agency of Northern California, the Vermont Department of Public Service and the Vermont Public Service Board, (together, "Joint Commenters"), submit their joint comments on the scope

[2] NECPUC's members include the Connecticut Public Utilities Regulatory Authority, Maine Public Utilities Commission, Massachusetts Department of Public Utilities, New Hampshire Public Utilities Commission, Rhode Island Public Utilities Commission, Vermont Department of Public Service and Vermont Public Service Board. The Maine Public Utilities Commission did not vote to join and takes no position on these comments.

[3] The Organization of MISO States, Inc. (OMS) is a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the Midwest Independent System Operator, Inc. (MISO). Its members are the Illinois Commerce Commission, Indiana Utility Regulatory Commission, Iowa Utilities Board, Kentucky Public Service Commission, Manitoba Public Utilities Board, Michigan Public Service Commission, Minnesota Public Utilities Commission, Missouri Public Service Commission, Montana Public Service Commission, North Dakota Public Service Commission, Public Utilities Commission of Ohio, South Dakota Public Utilities Commission and the Public Service Commission of Wisconsin. The Iowa Utilities Board, the Kentucky Public Service Commission, the Manitoba Public Utilities Board, and the Michigan Public Service Commission abstained and the Illinois Commerce Commission did not vote to join in the comments.

and implementation of the Commission's transmission incentives regulations and policies under Order No. 679.[4]

Incentive ratemaking, applied narrowly and appropriately, can be part of a sound policy to remove impediments to needed transmission infrastructure. As discussed below, however, Joint Commenters believe that the Commission must reevaluate and recalibrate its transmission rate incentive policy to better balance the interests of transmission owners and developers with the interest of consumers of electricity, and to ensure that both wholesale and retail electric customers (and the consumers they serve) pay only just and reasonable transmission rates, as the Federal Power Act ("FPA") requires. Accordingly, Joint Commenters welcome the opportunity to comment on the need for revisions to the Commission's current incentive rate policy. [5]

I. JOINT COMMENTERS' INTERESTS

The Joint Commenters are a diverse group composed of state public utility commissions, industrial users of electricity, public power utilities, consumer advocates, rural electric cooperatives, and trade associations representing such entities. All of them, however, share the conviction that end use consumers should pay only just and reasonable rates for transmission service under the Federal Power Act ("FPA").[6] While the Joint Commenters are not opposed to

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[4] *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[5] Many of the Joint Commenters are also filing individual comments in this docket and/or joining in additional comments being filed by other groups. Hence, the fact that Joint Commenters have submitted these comments should not be taken as an indication that any of the Joint Commenters share other positions expressed in other sets of comments being filed by other Joint Commenters in this docket. Moreover, the Joint Commenters have come together as an *ad hoc* group to prepare these consensus-based comments for the Commission's review and consideration. As with any such group, while the Joint Commenters generally support the policy recommendations set out in these Comments, not every Joint Commenter necessarily fully supports every position set out in them.

[6] The Commission's statutory duty is to ensure consumers are afforded "a complete, permanent and effective bond of protection from excessive rates and charges." *Atlantic Refining Co. v. Public Service Commission*, 360 U.S. 378, 388 (1959).

the granting of transmission rate incentives in circumstances where they are indeed required, they have been deeply concerned by the direction of the Commission's transmission rate incentive policy since the issuance of Order No. 679. Many of the Joint Commenters previously joined in comments filed in Docket No. RM10-23-000[7] on the issue of transmission rate incentives, to express their strong concerns with the Commission's ongoing application of its transmission rate incentives policy and the adverse impact this policy has on the ability of parties to reach transmission cost allocation solutions. As they there noted, the granting of transmission rate incentives, rather than being reserved for those cases in which incentives are truly needed to move a transmission project forward, are being granted routinely. Moreover, the packages of incentives granted, taken together, in many cases have gone far beyond what is required to reduce the risk of a transmission project to reasonable levels or to overcome barriers that would prevent needed projects from moving forward.

Joint Commenters therefore welcome the Commission's issuance of its NOI, and the willingness that it signals to reconsider the provisions of Order No. 679. They deeply appreciate the opportunity to submit comments on these issues.

II. COMMUNICATIONS

Joint Commenters request that service in this proceeding be made upon, and communications directed to, the following:

[7] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Docket No. RM10-23-000, Joint Comments of American Chemistry Council, *et al.*, filed September 29, 2010, available in FERC's e-Library as Submittal No. 20100929-5305.

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III. GENERAL COMMENTS

The Commission in its NOI requests comments on myriad aspects of its transmission rate incentive policy set out in Order No. 679 and implementing cases. In Section IV below, the Joint Commenters respond to these questions in detail, and support their responses with the statements of Jim Tracy, Hans Mertens and Ron Behrns, all of whom have extensive relevant transmission-related experience. In this section, however, the Joint Commenters provide their general views on the Commission's transmission rate incentive policy.

After several years of experience with the Commission's transmission rate incentive policies set out in Order No. 679 and its successors, it is time to take a close look at how those policies are functioning. A broad cross-section of the energy industry and its participants, including the Joint Commenters, agree that new transmission infrastructure is needed in the United States. But there exists an equally broad-based concern, also shared by the Joint Commenters, that the rapid expansion of the grid has been accompanied by an alarming escalation in the costs of transmission service, and that the ready availability of rate incentives has contributed to that escalation.[8]

Then-Commissioner Wellinghoff warned several years ago that Commission interpretations of the Order No. 679 nexus test were not "sufficiently rigorous."[9] The Commission was approving incentive adders, he pointed out, for "virtually all new transmission

[8] *See* Attachment A, a summary of FERC Orders on Incentive Applications for Transmission Development.

[9] *Bangor Hydro-Electric Co., et al.*, 122 FERC ¶ 61,265 at p. 62,543 (2008).

projects."[10] This problem, despite the warning, persists. The Commission's incentive rate policies, as Commissioner Norris has more recently observed, have become "too one-sided."[11]

The Commission, in reviewing applications for transmission rate incentives, should distinguish between those rate policies that reduce utility risk (full recovery of construction work in progress, increased abandoned plant cost protection, formula rates, and accelerated depreciation) and those that enhance utility/developer returns (rate of return adders and hypothetical capital structures). Return-enhancing incentives, except in extraordinary cases, should not be extended to those projects already receiving risk-reducing rate treatment; rather, the Commission should favor risk-reducing incentives over return-enhancing ones. The Commission should calibrate incentives to relative risk, rejecting incentive treatment for low risk projects (*i.e.*, projects that are routine or have alternative sources of funds available), entertaining requests for risk-reducing incentive treatment for projects of intermediate risk (*i.e.*, projects with significant and demonstrable risk elements), and reserving return enhancing incentives only for the highest risk projects.

The Joint Commenters also urge the Commission to limit the application of return-enhancing incentives, like rate of return adders, solely to the estimated, and not the ultimate actual costs of new transmission projects. Applying these incentive adders to actual project costs creates disincentives to cost containment and reliable cost estimates and will inappropriately reward transmission owners for coming in over budget. A utility cannot logically anticipate earning an incentive return on equity ("ROE") on unanticipated costs, removing any nexus

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[10] *Id.* at p. 62,543-44; *see also, Baltimore Gas and Electric Co.*, 121 FERC ¶ 61,167 (2007); *PPL Electric Utilities Corporation, et al.*, 123 FERC ¶ 61,068 (2008); *Commonwealth Edison Co., et al.*, 122 FERC ¶ 61,037 (2008).

[11] *Potomac Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 at p. 61,737 (2010) ("*PATH*").

between an ROE adder based on actual (rather than estimated) project costs and the decision to move forward with the project.

In considering applications for incentive rate treatment, the Commission should also consider whether lower ROE allowances for retail services already enhance the attractiveness of transmission investment for regulated public utilities. While the theory behind transmission rate incentives is that they will make transmission investments preferable to competing investment opportunities available to utilities, transmission projects face little internal competition for capital investments from distribution projects when base ROEs for transmission alone (*i.e.*, absent premiums) already exceed a public utility's corresponding retail ROE allowances.

The Commission's policies regarding RTO participation also merit reassessment. Although Order No. 679 contemplated case-by-case review of what size adder is appropriate for incentivizing RTO membership, the Commission in fact has applied a standard practice of granting an automatic 50 basis point adder not only for joining an RTO but for remaining a member. The incentives to induce RTO membership are qualitatively different from incentives to encourage *continued* membership. In the latter case, there is no justification for continuing the full 50 basis point adder years after a utility has joined an RTO (particularly where the utility's membership was required by regulatory order, merger condition, or otherwise) and it has effectively committed to participation.

Finally, if a utility cannot qualify for incentive rate treatment under Order No. 679, invocations of amorphous public policy justifications to grant incentive rate treatment anyway should be disfavored. Order No. 679 was intended to establish a policy to provide incentives for the construction of new transmission. There is already an extant 1992 Policy Statement addressing incentive rate requests outside this context.[12] Commission clarification that applications for incentive rate treatment outside of Order No. 679 must comply with the provisions of the 1992 Policy Statement would benefit the public interest by adding certainty and demanding more rigorous showings of need.

IV. SPECIFIC COMMENTS ON QUESTIONS POSED IN THE NOI

Q1: What have been the effects of the incentives policies adopted in Order No. 679 with respect to the goals set forth in section 219?

The short answer to this question is that there is no way to know. To be sure, significant transmission construction has occurred in the years since issuance of Order No. 679, much of it no doubt serving to improve reliability and/or reduce congestion. Since Order No. 679 did not incorporate either a "but for" test or a requirement that incentives be tied to specific performance objectives, however, there is no practical way to ascertain, after the fact, whether the incentives granted have had a positive effect or possibly no effect at all. But, as discussed further below, it *is* likely that, because of the numerous and often duplicative incentive mechanisms approved by the Commission and what the Chairman has described as a test for eligibility that was not "sufficiently rigorous," consumers have overpaid for any benefits that *did* result.

There are a number of obstacles that would prevent preparation of an after-the-fact analysis of the effects of the transmission rate incentives awarded under Order No. 679. The first is the difficulty in conducting such an analysis. The Commission could have, but chose not, to demand proof that projects would not have been built "but for" the availability of the incentives the Commission awarded.[13] In the past the Commission, guided by the courts, has examined

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[12] *Policy Statement on Incentive Regulation*, 61 FERC ¶ 61,168 (1992) ("1992 Policy Statement").

[13] In defining what constitutes a "nexus" under the nexus test, the Commission declined to impose a "but for" test that absent the incentives, the expansion would not occur, or a requirement for a showing of need. Order No. 679 at PP 48, 53. It also eliminated an earlier requirement that incentive requests be supported by a cost-benefit analysis. *Id.* at P 65; Order No. 679-A at PP 25, 35.

whether particular incentives in excess of cost-based rate allowances were necessary and to "see to it that the increase is in fact needed, and is no more than is needed, for the purpose."[14] To be sure, significant transmission facilities have been built or planned in the last few years. Without a "but for" test, however, there is, by definition, no way to know for certain whether these projects would have been built even in the absence of the Commission's incentive awards. In at least some significant cases, the projects were built because the transmission owners had contractual obligations to build them or had a statutory public service obligation to do so.[15] The Commission itself recently noted that prudent public utility transmission providers plan for the transmission facilities needed to maintain reliability or to reduce congestion. [16] As Jim Tracy observes in his attached statement, what the Commission's incentive policies added in such cases would be purely speculative.[17] Indeed, the depressed economy and the resulting dampened demand for electricity could equally explain reduced congestion or improved reliability.[18] As to whether the Commission's incentive policies may have accelerated the deployment of new transmission facilities, we see no evidence of such impact. Rather, its incentive policies may, in fact, have had the *opposite* effect. Because some transmission adders have applied to the ultimate costs of transmission projects, transmission owners would have the perverse incentive to

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[14] *Farmers Union Central Exchange Inc.*, 734 F.2d 1486, 1503 (D. C. Cir. 1984) (quoting *City of Detroit*, 230 F.2d 810, 817 (D.C. Cir. 1955)).

[15] The Commission in Order No. 679-A (at P 122) declined to find that an obligation to build a project should disqualify an applicant from eligibility for incentives.

[16] Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Docket No. RM10-23-000, 136 FERC ¶ 61,051, July 21, 2011 at P 83 ("Order No. 1000").

[17] Attachment B, Tracy Statement at P 6.

[18] *Id*. at P 7.

delay project completion if doing so would increase project costs and therefore the rate base to which the return adder would apply.[19]

In addition to rejecting application of a "but for" test in Order No. 679, the Commission also rejected tests that would have required the applicant to quantify benefits in relation to the costs of the incentives sought.[20] This policy choice, as the attached Tracy Statement explains, would make any effort to measure the efficacy of the Commission's policy difficult enough. But compounding the problem with any after-the-fact analysis is the insuperable obstacle of isolating the variables that have produced the types of benefits recognized in FPA Section 219 – improved reliability and lower delivered power costs resulting from reduced congestion. For example, the economy has suffered a substantial economic downturn over the last several years. The lower level of economic activity includes a dampening of power consumption. That, in turn, has in many instances reduced demand on the electrical grid, increasing reserve margins and reducing congestion. As Mr. Tracy notes, attempting to isolate the impacts of reduced economic activity and the impacts of transmission incentives approved by the Commission would be a futile undertaking.[21]

While it is nearly impossible to measure the effectiveness of the Commission's incentive rate policies in producing the benefits of increased reliability and/or reduced congestion, *if* these benefits resulted from the application of Order No. 679, consumers overpaid for them. Then-Commissioner Wellinghoff warned several years ago, in dissents to a series of Commission orders approving applications for transmission rate incentives, that the Commission was "not

[19] Attachment C, Mertens Statement at P 7.

[20] Order No. 679 at P 49.

[21] Tracy Statement at P 7.

applying a sufficiently rigorous nexus requirement" in cases implementing Order No. 679.[22] As a result, he added, the Commission was allowing application of ROE incentive adders "to virtually all new transmission projects."[23] Commissioner Norris voiced similar concerns in his recent concurrence to an order approving certain incentives for a transmission project in the PJM Interconnection L.L.C. ("PJM") region:

> [T]he Commission's current approach may not appropriately balance the different types of incentives awarded to a project. Some incentives, such as the collection of rates during construction work in progress (CWIP) and the approved recovery of prudently incurred costs if the project is abandoned, serve to substantially lower risk for investors in the project. Other kinds of incentives, such as an incentive ROE adder, give investors the opportunity for greater rewards. *The Commission has not articulated a sufficiently clear framework to balance requests for packages of incentives that individually seek to both limit downside risk and provide greater potential upside rewards.*[24]

Commissioner Norris's points are well-taken. In the past, for example, the Commission had observed that the availability of formula rates reduced the financial risks public utilities faced and was a factor that should reduce a utility's return allowance.[25] As the Commission explained in *Indiana and Michigan Power Co*., a cost-of-service tariff:

> permits immediate recovery of any increase in costs, thus limiting [the utility's] risk and minimizing not only the risk of regulatory lag, but also the risk of disapproval. It will automatically make its allowed rate of return on equity regardless of whether it delivers the power or not. The steady stream of revenues

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[22] *See, e.g., Bangor Hydro-Electric Co., et al.,* 122 FERC ¶ 61,265 at p. 62,543-44 (2008).

[23] *Id.*; *see also, Baltimore Gas and Electric Co.,* 121 FERC ¶ 61,167 (2007); *PPL Electric Utilities Corporation, et al.,* 123 FERC ¶ 61,068 (2008); *Commonwealth Edison Co., et al.,* 122 FERC ¶ 61,037 (2008).

[24] *PATH*, 133 FERC ¶ 61,152 at p. 61,737 (2010) (emphasis added).

[25] *See, e.g., Northeast Utilities Service Co. (Re Public Service Company of New Hampshire),* 56 FERC ¶ 61,269 at p. 62,053 (1991); *Indiana & Michigan Power Co.*, 4 FERC ¶ 61,316 at p. 61,739 (1978); *South Carolina Generating Co.,* 40 FERC ¶ 61,116 at p. 61,311 (1987).

> from such an arrangement provides the company with a very real advantage over those utilities not operating under similar cost-of-service tariffs.[26]

This reduced risk factor, the Commission has held, justifies a lower return allowance.[27] Yet, more recently, the Commission has granted incentive adders to public utilities that already possess formula rates without so much as a nod to the significance of this factor.[28]

In sum, because of the Commission's failure to: (1) require a "but for" showing by applicants as a precondition to the granting of transmission rate incentives; (2) tailor the package of incentives granted for a particular project to the corresponding risks; (3) require the quantification of costs and benefits; and (4) take into account external factors such as the availability of formula rates, the answer to Question 1 is "we cannot know, but we do know that consumers substantially overpaid for the new transmission facilities that have been constructed."

Q2: Are the Commission's incentives policies appropriately promoting investment in transmission infrastructure in accordance with section 219?

No, the incentives provided have not been "appropriate," for the reasons noted in the response to Question No. 1. Section 219 did not change the just and reasonable standard under

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[26] 4 FERC ¶ 61,316 at p. 61,739.

[27] *Id*.

[28] In recent years, the Commission has approved formula rates that even further reduce the transmission owner's risk. Traditionally, formula rates have allowed utilities to recover their actual historical costs and to revise their inputs annually based on the prior year's actual costs. More recently, several utilities have sought and received authorization to include *estimated* future costs in their formulas, what FERC has described as "a forward looking formula rate using projected test period cost inputs with an annual true-up, rather than a formula rate based on historical test period data." *See. e.g.*, *Otter Tail Power Co.*, 129 FERC ¶ 61,287 at P 5 (2009); *see also*, *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284 (2007); *Michigan Elec. Transmission Co.*, 117 FERC ¶ 61,314 (2006); *Virginia Elec. and Power Co.*, 123 FERC ¶ 61,098 (2008); *Public Serv. Elec. & Gas Co.*, 124 FERC ¶ 61,303 (2008); *ITC Holdings Co.*, 121 FERC ¶ 61,229 (2007); *Int'l Transmission Co.*, 116 FERC ¶ 61,036 (2006). While the operation of these formulas, too, contemplates an annual true up to reflect costs actually incurred in a prior period, the use of estimated future costs allows the filing utility to avoid even the very limited time lag associated with the difference between historical costs used to establish charges each year and the actual costs incurred by the utility. Indeed, that is the purpose of this type of formula rate. *Otter Tail*, 129 FERC ¶ 61,287 at P 19. Thus, the Commission should not only factor into evaluation of incentive rate requests whether the applicant has formula rates, but whether these formula rates give it even additional risk protection by allowing charges to be based on estimated costs.

Sections 205 and 206. Indeed, Section 219(d) specifically states 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 824d and 824e of this title that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential." The Commission's insufficiently rigorous nexus test has likely caused consumers to incur more costs than necessary to achieve Section 219's goal of promoting investment in infrastructure that would reduce congestion or improve reliability.

While calculating the benefits to consumers associated with the Commission's incentive rate policies is not possible,[29] we do know that the Commission's policies have increased transmission rates by hundreds of millions, if not billions of dollars. As Ron Behrns notes in his attached statement, accepting that *some* incentive may have been needed to encourage *some* of the transmission projects that have been found eligible for rate incentives, it would be the extraordinary case, not the usual one, where rate of return adders – rather than risk-reducing mechanisms – would have been warranted.[30] Yet we know that for scores of projects, the Commission has approved rate mechanisms (*e.g.,* formula rates, CWIP, abandoned plant cost protection, and combinations thereof) that greatly reduce the transmission owner's risk and, at the same time, has granted rate of return adders for the same projects – rate adjustments normally reserved for undertakings that pose *added* risk. As Mr. Behrns notes, this, by definition, has resulted in consumers overpaying for any project benefits.[31]

A review of Commission actions in some illustrative cases shows how Commission incentive rate policies have required consumers to overpay for new transmission facilities. In

[29] *See* response to Question No. 1 above; Tracy Statement at PP 6-10.

[30] Attachment D, Behrns Statement at P 10.

[31] *Id*. at P 11.

New England, for example, the Commission approved transmission rate of return adders worth several hundred million dollars to New England transmission owners even though these companies: (1) already have formula rates; (2) already have abandoned plant cost recovery; and (3) were already contractually obligated to construct the facilities in question under the terms of their Transmission Operating Agreement with ISO New England.[32] While the Commission reasoned that the adder provided greater incentives to the applicants to bring needed transmission on line sooner,[33] it initially established no deadlines for completion of the projects as a condition of eligibility,[34] and, when it later added a deadline,[35] it subsequently granted waivers.[36] The Commission required no showing by the applicants that the benefits of early deployment were worth the additional cost, nor any showing that the incentives themselves had even produced accelerated deployment.[37]

As recently as June of this year, the Commission, over Chairman Wellinghoff's dissent, reaffirmed its decision to grant a combination of ROE adders and risk-reducing incentives for the

[32] Attachment K of the ISO-NE Open Access Transmission Tariff ("OATT") imposes an obligation on incumbent transmission owners to construct upgrades as determined by the regional plan. *See* ISO New England Open Access Transmission Tariff, Attachment K, § 8; *see also* Transmission Operating Agreement at Schedule 3.09(a) (obligating transmission owners to build facilities and make upgrades for reliability and market efficiency as determined by the Regional System Plan).

[33] *Bangor Hydroelectric Co., et al*., 117 FERC ¶ 61,129 (2006).

[34] *Id*.

[35] *Bangor Hydroelectric Co., et al*., 122 FERC ¶ 61,265 at P 55 (2008).

[36] *See, e.g., Northeast Utilities Service Co*., 124 FERC ¶ 61,044 at P 1 (2008).

[37] To be sure, under the deferential standard of review accorded Commission decisions the Commission was not required to demand these showings from the applicants before awarding incentive adders. *Connecticut Dept. of Public Utility Control v. FERC*, 569 F.3d 477 (D. C. Cir. 2009). Joint Commenters presume from the Commission's decision to issue the NOI that it has chosen to reconsider its policy choices in this area, its authority to apply them notwithstanding. The flexibility of an agency to reexamine its prior policies in light of experience and changing circumstances is the hallmark of administrative law. *American Trucking Ass'n v. Atchison, Topeka and Santa Fe Railway Co.*, 387 U.S. 397, 416 (1967) ("Regulatory agencies do not establish rules of conduct to last forever; they are supposed, within the limits of the law and of fair and prudent administration, to adapt their rules and practices to the Nation's needs in a volatile, changing economy. They are neither required nor supposed to regulate the present and the future within the inflexible limits of yesterday.")

New England East-West Solution Transmission Project ("NEEWS") proposed by Northeast Utilities and National Grid USA, even though the transmission owners of that project were contractually obligated to build it. While acknowledging its statement in Order No. 679 that a contractual obligation to build "could" be a factor relevant to evaluation of the applicant's request for incentive rate treatment, the Commission rejected protests that it had failed to give the contractual obligation any weight in its analysis, concluding that it was the protesters' responsibility to "show that such obligations are relevant" and that "neither Municipals nor the Joint Protesters provided the Commission with any reason why Applicants' obligation to build should factor into the nexus test in this particular case."[38] But a preexisting obligation to build is self-evidently relevant to the need for incentives. The Commission itself has long noted that denying incentive rate treatment to utilities for undertaking what they are already obligated to do is in the public interest.[39]

The Commission has also approved incentive adders for transmission projects in New England that apply to actual project costs, not the estimates of project costs presented to the Commission at the time the incentive adders were requested. Consumers, as a result, have paid more than an additional $100 million in adder charges because qualified projects have run double or more their original estimated costs.[40] The Commission explained several years after granting the adders that the *sole* qualifying criteria for the adders was whether the projects had been approved in the New England planning process; the estimated cost to the ratepayer was

[38] *Northeast Utilities Service Co. and National Grid USA*, 135 FERC ¶ 61, 270 at P 19 (2011).

[39] *See, e.g., New England Power Pool*, 97 FERC ¶ 61,093 at 61,477 (2001) ("This decision is in the public's interest as it does not unjustly reward NEP for doing what it is supposed to do.").

[40] *See New England Conference of Public Utilities Commissioners, Inc. v. Bangor Hydro-Elec. Co., et al.*, Complaint of the New England Conference of Public Utilities Commissioners, Inc. Seeking Limitation on Amount of Transmission Costs to Which Incentive ROE Adder Applies, filed June 12, 2008, Docket No. EL08-69-000, Exhibit A.

irrelevant.[41] When ROE adders are applied to the ultimate costs of the projects, not the project sponsors' estimated cost of the projects, transmission project developers are given the perverse incentive to bring their projects in over-budget, since they will earn additional return dollars for doing so.

Similarly, in PJM, rather than make a detailed analysis of whether projects meet the requirement to demonstrate that they will provide reliability benefits and are non-routine, the Commission has relied excessively – in some cases almost solely – on whether a project has been included in PJM's Regional Transmission Expansion Plan ("RTEP"). Here too, the Commission has granted ROE adders where the transmission owners were already obligated to construct the facilities, but has offered no explanation for why this factor should not have militated against awarding the adders. The result of the Commission's near automatic assumption that projects that were included in the RTEP meet the Order No. 679 requirement to ensure reliability benefits or reduce the cost of delivered power by reducing congestion is that millions of dollars in adders have been – and are still being – collected for projects that might not convey any such reliability or congestion benefits. Moreover, the Commission's determination in *Baltimore Gas and Electric Co.* ("*BG&E*") that PJM RTEP baseline projects should be deemed to meet the Order No. 679 nexus requirement has been relied upon as a substitute for case specific evaluation.[42] While the Commission subsequently clarified that *BG&E* does not mean that projects in PJM's RTEP will qualify automatically for incentives,[43] in practice, the policy appears unchanged. For

[41] *New England Conference of Public Utilities Commissioners, Inc. v. Bangor Hydro-Electric Co.*, 124 FERC ¶ 61,291 at P 44 (2008) *reh'g denied*, 135 FERC ¶ 61,140 (May 19, 2011) ("[T]he Commission authorized the incentive in Opinion No. 489 without reference to the cost estimates of specific projects and not on the basis of any criteria apart from their RTEP status.").

[42] 120 FERC ¶ 61,084, *order on reh'g*, 122 FERC ¶ 61,034 (2008).

[43] *Commonwealth Edison Co.*, 124 FERC ¶ 61,231 (2008).

example, in a proceeding regarding Virginia Electric and Power Company's request for incentive rate treatment, the Commission found that elements of the Order No. 679 incentive rate requirements were met simply because projects were included as PJM RTEP baseline projects.[44] This has led to the award of several million dollars in incentives that were not warranted, or at least not sufficiently reviewed and explained by the Commission.

Transmission owners in Midwest Independent Transmission System Operator ("MISO") also have an obligation to construct transmission facilities that are approved in the MISO planning process.[45] But, as has been the case in PJM and New England, the Commission has granted MISO transmission owners incentive rate treatment for projects they were obligated to build.[46] And, as has been the case in PJM and New England, the Commission's orders give no indication that the existence of these contractual obligations has been given any weight in the Commission's decisions whether to grant or modify the incentives requested.

Finally, it bears emphasis that, in the experience of the Joint Commenters, most of the transmission projects that have been the subject of the Commission's incentive orders have

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[44] *Virginia Electric and Power Co.*, 124 FERC ¶ 61,207 (2008), *reh'g pending*.

[45] *See* Midwest ISO, Tariff, Attachment FF, Section VI C. The MISO Tariff provides:

> Approval of the MTEP by the Transmission Provider Board certifies it as the Transmission Provider plan for meeting the transmission needs of all stakeholders subject to any required approvals by federal or state regulatory authorities. The Transmission Provider shall provide a copy of the MTEP to all applicable federal and state regulatory authorities. The affected Transmission Owner(s), or other designated entity(ies), shall make a good faith effort to design, certify, and build the designated facilities to fulfill the approved MTEP. However, in the event that a proposed project is being challenged through the dispute resolution procedures under this Tariff, the obligation of the Transmission Owners, or other designated entity(ies), to build that specific project (subject to required approvals) is waived until the project emerges from the dispute resolution procedures as an approved project. The Transmission Provider Board shall allow the Transmission Owners, or other designated entity(ies), to optimize the final design of specific facilities and their in-service dates if necessary to accommodate changing conditions, provided that such changes comport with the approved MTEP and provided that any such changes are accepted by the Transmission Provider. Any disagreements concerning such matters shall be subject to the dispute resolution procedures of this Tariff.

[46] *See, e.g., Ameren Services Co.*, 135 FERC ¶ 61,142 (2011).

involved facilities installed to satisfy the reliability needs of the regions in which they have been built. Projects designed to reduce congestion in order to lower delivered power costs – referred to in some regions as "market efficiency" projects – by contrast, have been few and far between. This is not to say that transmission projects to improve reliability should not qualify for incentives. But it does warrant note that improving and maintaining reliability are core functions of public utilities that should not ordinarily merit incentive rate treatment.

The experience in PJM, in particular, points up the weak correlation between the Commission's incentive rate policies and the construction of new transmission infrastructure that has occurred since the policy was implemented. Within PJM, decisions to propose and construct new transmission infrastructure for the purpose of reducing congestion, unlike reliability projects, are based on a bottom-up decision model. Entities, such as incumbent transmission owners located in PJM, can propose to build these market efficiency projects based on the needs of the market as it is reported by PJM. Yet – notwithstanding the current Commission policy as to the availability of incentives for such projects – proposals to build new transmission systems or to upgrade the current systems with the goal of reducing congestion within PJM have been virtually nonexistent. As noted above, there has been a similar experience in New England. The paucity of market efficiency projects, however, should not be construed as evidence that the problem is the lack of sufficient return-enhancements.

The only "market efficiency" projects proposed in PJM in recent years were two companion projects developed by a merchant transmission provider, Northeast Transmission Development LLC, a subsidiary of the LS Power Group.[47] And the applicant in *that* case

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[47] *See Northeast Transmission Development, LLC*, 135 FERC ¶ 61,244 (2011). On April 6, 2011, Northeast Transmission Development, LLC ("Northeast"), filed a petition ("Northeast Petition") in Docket No. EL11-33 seeking a declaratory order from the Commission for incentive rate treatment as to two market efficiency projects. Northeast is proposing to build within the PJM control area specifically

eschewed any request for an enhanced return allowance other than the RTO participation adder.[48] LS Power has previously stated that the principal impediment to development of market efficiency projects is not the lack of return-enhancing incentives, but the lack of competition faced by incumbent transmission providers.[49]

It seems apparent that current incentive rate policies are not appropriately promoting the growth of new transmission infrastructure to improve reliability or to reduce congestion. As to reliability enhancements, it is not reasonable to believe that the availability of incentives plays any substantial part in the determination as to the reliability needs of the transmission system.

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to reduce congestion. *Id.* at PP 5-7. Northeast's filing states that its two proposed projects would be the first major transmission lines to be approved in PJM as market efficiency projects. *Northeast Transmission Development, LLC*, Petition for Declaratory Order on Incentive Rate Treatments, filed April 6, 2011, Docket No. EL 11-33, at 13-15 ("Northeast Petition"). In fact, the Northeast Petition states that only *one* market efficiency project has been previously approved by PJM for inclusion in the RTEP, a relatively minor 230 kV transformer and transmission line upgrade. *Id.* at 13, n.27.

[48] As Northeast states in its Petition (at 29):

> Based on Commission precedent, Northeast Transmission's development of the Projects would appear to qualify for additional rate incentives identified in Order No. 679, such as an ROE adder of 100 basis points in recognition that it is a Transco, an ROE adder to reflect the risks and challenges facing the Liberty East Project and the Kanawha Project, a hypothetical capital structure during construction, use of accelerated depreciation of fifteen years or less, and inclusion of CWIP in rate base. However, Northeast Transmission is mindful that the incentive measures requested, taken together, must balance the need to reduce the risk for the Projects sufficiently to allow Northeast Transmission to raise capital in sufficient amounts at reasonable cost with the need to ensure that rates to consumers remain just and reasonable. Northeast Transmission has tailored its request to the minimum package of incentives needed given the risks and challenges faced by each project consistent with ensuring just and reasonable rates and, consequently, does not request any of the additional incentives outlined above.

[49] *See, e.g.*, LS Power Comments, Docket No. RM10-23, at 38-39, Sept. 29, 2010:

> To date, the Commission has used its incentive rate authority to make certain that needed transmission was being built because incumbent transmission owners made it clear that those incentives were necessary for them to economically build that transmission. By opening up transmission development to independent developers, the Commission will only need to use incentive rates where they are really needed, when there is no one willing to build a needed project, or where the cost savings achieved warrant a reward and thus incentive rates on the overall lower cost. Consumers benefit when costs are compared fairly and consistently.

Similarly, even when the decision-making ability is put directly in the hands of market participants as to what market efficiency projects should be proposed, the availability of return-enhancing incentive rates does not appear to be a determining factor.

Nonetheless, the result of the Commission's past application of its incentive rate policy under Order No. 679 is that, in many cases, transmission project developers have been granted rate incentive packages (in many instances over the strong objection of those being asked to pay them) that in the Joint Commenters' view substantially exceed the incentives that would result in just and reasonable rates.[50] Among these cases are:

Green Power Express LP, Docket No. ER09-681-000, 127 FERC ¶ 61,031 (2009), *order approving settlement*, 135 FERC ¶ 61,141 (2011). (Applicant requested: (1) recovery of costs of abandoned facilities; (2) deferred recovery for start-up, development and pre-construction costs through the creation of regulatory assets; (3) 100 percent CWIP in rate base; (4) a hypothetical capital structure of 60 percent equity and 40 percent debt; and (5) a 160 basis point incentive ROE adder (50 basis points for participating in a RTO, 100 basis points for independence, and 10 basis points for the risks and challenges of the Project), for an overall ROE of 12.38 percent; and (6) a formula rate structure under which the costs of the Project would ultimately be recoverable through the applicable open access transmission tariffs of Midwest Independent Transmission System Operator, Inc. (Midwest ISO and PJM Interconnection, L.L.C. (PJM). The Commission granted all requested incentives except for the formula rate request, which was set for hearing/settlement proceedings.).

Green Energy Express LLC, Docket No. EL09-74-000, 129 FERC ¶ 61,165 (2009), *reh'g denied*, 130 FERC ¶ 61,117 (2010). (Applicant sought: (1) deferred recovery of pre-commercial expenses; (2) inclusion of 100 percent of CWIP in rate base; (3) abandoned plant recovery; (4) an ROE adder of 50 basis points for participation in a qualifying Transmission Organization; (5) an ROE adder of 100 basis points in recognition of Green Energy's status as a transco; (6) an ROE adder of 50 basis points to otherwise compensate for the unique risks and challenges facing the Project and Green Energy's investors; and (7) a hypothetical capital structure of 50 percent equity and 50 percent debt until the Project was placed in service. The Commission conditionally granted the Applicant's request for these incentives, conditioned on it submitting a filing that met certain criteria set out in the California Independent System Operator Corporation's

[50] Joint Commenters do not claim that the incentives the Commission has awarded to date cannot withstand judicial scrutiny. In a number of cases, the Commission's orders have, in fact, been found to satisfy the courts' deferential standard of review. The issue here, however, is not whether the Commission could continue to apply its Order No. 679 policies, but whether it *should*.

("CAISO") planning process. Commissioner Kelly dissented from the grant of the 50 basis point ROE adder.).

Bangor Hydro-Electric Co., et al, Docket No. ER04-157, 117 FERC ¶ 61,129 (2006) ("Opinion No. 489"), *affirmed, Connecticut Dept. of Public Utility Control v. FERC*, 569 F.3d 477 (D. C. Cir. 2009). (Applicants, already operating under formula rates and under a contractual obligation to build new transmission facilities, were awarded a 100 basis point adder for new transmission projects. At the time the Commission approved the adder, the expected cost to consumers was $148 million, but cost overruns – to which the adder also applies – have nearly doubled the cost of the adder.[51]).

Virginia Electric and Power Co., Docket No. ER08-1207, 124 FERC ¶ 61,207 (2008), *reh'g pending.* (FERC granted applicants' request for 150 basis point adders for four projects and 125 basis point incentive adders for an additional seven projects. The projects for which incentive rate treatment was granted include several projects that were arguably routine in nature, as well as a project that had not yet been approved in the PJM RTEP.).

Baltimore Gas and Electric Company - Mid-Atlantic Power Pathway ("MAPP"), Docket No. ER09-745-000, 127 FERC ¶ 61,201 (2009), *reh'g denied*, 130 FERC ¶ 61,210 (2010). (Applicant requested: (1) 150 basis point adder to its authorized Base ROE of 11.30 percent, for an overall ROE of 12.8 percent; and (2) abandoned plant recovery. Applicant's portion of the MAPP project was 10.4 miles, or about 4.5 percent, of the entire 230-mile MAPP project. In addition, Applicant's portion of the MAPP project: (1) was located entirely within Applicant's existing right-of-way and within a single jurisdiction; (2) would not be constructed by the Applicant; and (3) involved construction of a "traditional" overhead transmission line, unlike the rest of the MAPP project, which involved the use HVDC technology as well as construction over or under the Chesapeake Bay and Potomac River and across the Delmarva Peninsula on which are located many square miles of wetlands. The Commission granted all requested incentives. Commissioner Kelly dissented from the grant of the 150 basis point ROE adder.)

Potomac-Appalachian Transmission Highline ("PATH"), Docket No. ER08-386, 122 FERC ¶ 61,188 (2008). (Applicant sought: (1) 50 basis point adder to authorized ROE for membership in qualifying RTO; (2) approval of ROE at the high end of the zone of reasonableness or alternatively, approval of a 150 basis point adder (separate and in addition to the RTO membership adder) to result in an overall ROE of 14.3 percent; (3) approval to include 100 percent CWIP in rate base; (4) amortization of development (pre-commercial) costs over 60 months; (5) hypothetical capital structure of 50 percent equity and 50 percent debt until completion of construction of the PATH project; and (6)

[51] *See New England Conference of Public Utility Commissioners et al. v. Bangor Hydro-Electric Co., et al*, Docket No. EL08-69, Complaint at 1-2, 11 (filed June 12, 2008), *complaint denied, New England Conference of Public Utilities Commissioners, Inc. v. Bangor Hydro-Electric Co., et al.*, 124 FERC ¶ 61,291 (2008), *rehearing denied*, 135 FERC ¶ 61,140 (2011).

abandoned plant recovery. The Commission granted all requested incentives (including a 14.3 percent overall ROE), except for the formula rate request, which was set for hearing/settlement proceedings. Commissioner Kelly dissented from the Commission's decision to establish an ROE directly in the order rather than set the ROE determination for evidentiary hearing. Then-Commissioner Wellinghoff also dissented from the majority's decision to grant PATH an ROE of 14.3 percent. On November 19, 2010, FERC issued its Order on Rehearing, which granted rehearing on the issue of establishing a base ROE and establishing a suitable proxy group through full evidentiary hearings.[52] Commissioner Norris issued a separate statement expressing his concerns about the Commission's application of its incentive rate policy. The Commission's 2008 Order had granted PATH a 12.3 percent base ROE. Commission-sponsored settlement discussions are currently continuing among the parties.

Trans Bay Cable, LLC, Docket No. ER05-985-000, 112 FERC ¶ 61,095 (2005), *order on clarification*, 114 FERC ¶ 61,031 (2006). (Applicant sought and received through approved Rate Principles: (1) a 13.5 percent post-tax ROE, significantly in excess of the prevailing returns earned by major Participating Transmission Owners within the CAISO; and (2) a hypothetical capital structure of 50 percent equity and 50 percent debt for the first three years of the project's commercial operation, when the actual capital structure was estimated by parties to be approximately 70 percent debt and 30 percent equity. Subsequently, in Docket No. ER10-116-000, the Commission did reject Transbay's additional request for a 50 basis points adder for placing the facility under the operational control of an RTO.[53] It is also notable that the incentives are now applied to project costs that have ballooned from $300 million at the time of CAISO planning approval, to $521 million net plant in service as per Transbay's own rate filing.).

Northeast Utilities Service Co. and National Grid USA, 135 FERC ¶ 61,270 (2011). (Applicants sought a 150 basis point adder for new transmission, abandoned plant cost protection, and CWIP for a $2 billion transmission project they were contractually obligated to build. Although the Commission acknowledged that Applicants' existing formula rate reduced their risk, as did CWIP and abandoned plant cost protection, it approved all the requested incentives, adjusting the adder downward by only 25 basis points. Since the Commission did not reexamine the Applicants' existing 11.64 percent ROE, the resulting approved ROE was 12.89 percent. Chairman Wellinghoff dissented in part.).

[52] *PATH*, 133 FERC ¶ 61,152 (2010).

[53] *Trans Bay Cable, LLC*, 132 FERC ¶ 61,083 (2010).

Q3: Some barriers to construction of new transmission facilities fall outside of the Commission's jurisdiction. How do the Commission's incentives policies affect such barriers?

The Commission is correct that there are barriers to construction of new transmission that fall outside of its jurisdiction. It is unlikely that the Commission's incentive policies can overcome such barriers. Simply "throwing money at the problem" by providing an overgenerous package of risk-reducing and return-enhancing incentives certainly does not surmount such barriers. Worse yet, it creates other problems, by increasing resistance to the allocation of transmission costs. As a number of Joint Commenters pointed out in the joint comments they filed last fall in Docket No. RM10-23-000, the larger the size of the transmission revenue requirement to be allocated, the more difficult it is do so.

Q4: How can the Commission's rate incentives policies balance the need for regulatory certainty with the changing investment climate over time? Are there metrics the Commission should monitor to achieve this balance, and if so, what are they? Are there other factors that change over time that the Commission should consider in evaluating incentives applications? Should the Commission consider these changes over time on a generic or case-by-case basis?

To date, the Commission has not taken into account the reasonableness of previously approved base return allowances in effect at the time an applicant submits a request for incentive rate. Nor has it considered whether the applicant's current return allowance is already higher than needed to attract investment before incentive enhancements. This is not an inconsequential matter. In the years since the issuance of Order No. 679, conditions in the United States' (indeed the world's) economy have changed profoundly. The Nation has undergone its most severe economic contraction since the Great Depression, and it does not appear to be over yet. Interest rates are at historic lows, and unemployment is over 9 percent. Given the fundamental changes in economic conditions that may have occurred since the return allowance was originally approved, the Commission should reexamine its policy of granting incentive adders without simultaneously examining the reasonableness of the underlying, or base rate of return allowance. Simply put, the rate of return needed to attract investment in a long-lived asset that is used to provide a monopoly service is less than it was a few years ago. The Commission needs to acknowledge this reality and incorporate consideration of reasonableness of the applicant's base rate of return at the time it seeks an enhanced return allowance.

As to the question whether the Commission should consider changed conditions on a generic or case-by-case basis, the short answer is that the concern is generic, but the solution will need to be applied on a case-by-case basis. For example, if a utility's request for incentive rate treatment coincides with a general rate increase filing, the utility's base return would be examined as part of that process. But some applicants, well-satisfied with return allowances set years earlier, may seek return adders or other incentive rate treatment for new transmission facilities, taking the existing return allowance as a given. In such cases, if the issue is raised, the Commission should engage in a proactive review of the reasonableness of the applicant's existing return allowance.

Finally, the Commission must consider the state-awarded return allowances provided to the same entities applying to the Commission for transmission rate incentives. As noted in the response to Question No. 8 below, state-awarded return levels have generally been below the base return awards granted by this Commission.

Q5: Should specific rate incentives be tailored to address specific goals set forth by Congress in section 219?

Q6: Are there other factors or considerations which the Commission should consider as part of its transmission incentives policies, in order to be consistent with the goals of section 219?

As noted in response to Question No. 2, Section 219 did not change the just and reasonable standard under Sections 205 and 206 of the FPA. Section 219 only added a requirement for the Commission to have in place an incentive policy to encourage the development of transmission facilities that would benefit consumers by improving their reliability of service or reducing the cost of delivered power by reducing congestion. Historically, the Commission has demanded that applicants for incentive rates demonstrate and quantify actual benefits. Nothing in Section 219 obligated the Commission to abandon such a requirement as a prerequisite for incentive rate eligibility.

Section 219 refers to incentives to improve transmission reliability, but it is implicit in that Section's express preservation of Section 205 and 206 standards of justness and reasonableness that Congress could not have intended to promote marginal improvements in transmission reliability achieved at disproportionate cost. Nor is it reasonable to assume that transmission owners should be awarded incentives for reducing congestion – irrespective of the cost to consumers – so long as they result in some reduction in delivered power costs. At a minimum, achievement of Section 219's goals requires the reward of incentives to be tied to associated benefits. The principal flaw in the Commission's existing incentive rate policy is that it demands no accountability from applicants. They do not have to quantify benefits, even roughly, nor does the Commission in many instances tie the incentive rate treatments granted to actual performance. As noted in response to earlier questions, it is these flaws in the Commission's existing policy that make it impossible to ascertain whether its existing policies have been successful in achieving the goals of Section 219.

The most important factors the Commission should consider as part of its transmission incentives policies are: (1) whether the applicants can demonstrate a measurable benefit (in the form of increased reliability or lower delivered power costs) to consumers that is likely to be realized if the specific incentive is granted; (2) whether the applicant can demonstrate a causal relationship between each incentive sought and the consumer benefits to be derived from that incentive; and (3) whether the applicant can demonstrate that the benefits to be gained by consumers materially exceed the costs of the requested incentives. These factors must be considered to ensure that the incentives awarded further the goals of Section 219 and meet the just and reasonable standard specifically retained in that section.

Q7: Have the incentives granted to transmission projects had an impact on consumer rates and service, including impacts related to reliability and the reduction of congestion?

As noted in response to Question No. 1, it is impossible to say whether there has been a positive impact on reliability or delivered power costs resulting from the Commission's implementation of Section 219. Chairman Wellinghoff noted early in the administration of Order No. 679 that the Commission was "not applying a sufficiently rigorous nexus requirement." The absence of any requirement that applicants either: (1) demonstrate a causal relationship between their incentive requests and the benefits they expect their projects to produce; or (2) produce a cost/benefit study as part of their applications for incentive rate treatment, makes meaningful after-the-fact analysis of the success of the Commission's incentive rate orders impossible. But if there has been a positive impact traceable to the incentives the Commission has granted, the evidence, discussed earlier, is clear that consumers have overpaid for any benefits they have received.

Q8: Have the incentives granted to transmission projects had an impact on investment patterns in the electricity industry? Do the incentives impact the allocation of investment capital among transmission, generation, and distribution facilities?

As noted earlier, the Commission's nexus test has left it and the public with little ability to measure the effects of its transmission rate incentive policies after-the-fact. That said, one likely effect of the Commission's incentive rate policy, as discussed in the statement of Mr. Tracy, is that the investment decisions of vertically integrated utilities may have been skewed away from investment in distribution (where state-set return allowances have been lower) and into transmission plant.[54] This conclusion, we should add, is consistent with the Commission's own expectations.

In Order No. 679, the Commission stated: "We expect that an incentive ROE will make transmission projects more attractive, and therefore more likely, when transmission projects must compete for capital in vertically integrated utilities as well as in transmission and delivery utilities."[55] If the theory behind granting transmission incentives is that they are required because transmission projects must compete with other investment opportunities, it logically follows that the overall effect of potential incentives on the comparative attractiveness of other investment opportunities, such as a utility's distribution investments, will be an underinvestment in the latter. In other words, because the utility has only a finite amount of capital to invest, increased investments in transmission will translate into underinvestment in distribution. ROE awards by the Commission which are significantly more generous than relevant state ROE allowances in effect could skew utility investment decisions as between transmission and distribution level infrastructure additions.[56]

Under the seminal case law in this area,[57] a utility rate of return should be sufficient to: (1) maintain the financial integrity of the enterprise; (2) enable the company to attract new capital; and (3) provide a return to the common equity owner that is commensurate with returns on investments in other enterprises of corresponding risk. As the Supreme Court stated in

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[54] Tracy Statement at P 15.

[55] Order No. 679 at P 91.

[56] Tracy Statement at P 15.

[57] *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944) ("*Hope*"); *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923) ("*Bluefield*").

Bluefield, "[a] rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."[58]

As the Commission knows well, the economy has gone through a protracted recession, from which it has been struggling to emerge. This has been reflected in declining bond yields. In the summer of 2003, long-term U.S. Treasury yields hit a 60-year low at 3.33 percent. They subsequently increased and fluctuated between the 4.0 percent and 5.0 percent levels over the next four years in response to ebbs and flows in the economy. Ten-year Treasury yields began to decline in mid-2007, at the beginning of the current financial crisis. In 2008 Treasury yields declined to below 3.0 percent as a result of the expansion of the mortgage and subprime market credit crisis, the turmoil in the financial sector, the government bailout of financial institutions, and the economic recession. On August 4, 2011 (a day when the Dow Jones industrial average lost 512.76 points, and investors fled to investments they perceived to be safer), the yield on the ten-year treasury note tumbled to just 2.46 percent by 3:00 p.m.[59] On August 8, 2011 (the Monday that markets reacted to the downgrade by Standard & Poor's of the United States' sovereign debt rating the prior Friday evening, with the Dow falling a further 634.76 points), investors poured money *into* U.S. treasury bonds, and the yield of the ten-year treasury was pushed down to 2.339 percent.[60] On Tuesday, August 9, 2011, the Federal Reserve issued a

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[58] *Bluefield*, 262 U.S. at 693.

[59] Tom Lauricella, *Stocks Nose-Dive Amid Global Fears: Weak Outlook, Government Debt Worries Drive Dow's Biggest Point Drop Since '08,* Wall Street Journal, Friday, August 5, 2011, at A7.

[60] Matt Phillips & Min Zeng, *Downgrade Raises Treasurys' Appeal*, Wall Street Journal, Tuesday, August 9, 2011, at A4.

statement including plans to keep interest rates near zero for at least the next two years.[61] By September 9, 2011, the yield on the ten-year treasury note had fallen to 1.93 percent.[62] In such unsettled economic times, investors will no doubt continue to seek out lower risk investments.[63] And while utility equity costs might not move in lock-step with bond yields, it is unlikely that they will spike back up to anywhere near the levels that might justify the range of incentive ROE awards the Commission has granted in recent years.[64] Utility equities will likely continue to be considered a relatively safer class of investment, and investors will continue to seek them out.[65]

A number of state regulatory authorities have adjusted allowed ROEs in the past several years to reflect these events, but such adjustments have not occurred as frequently at the wholesale level. The following table shows examples of state-level and Commission ROE allowances currently in effect for the same utility:

Company	FERC base ROE	State ROE
National Grid (MECo/Nantucket)	11.14 (2006)	10.35 (MA 2009)[66]

[61] Sudeep Reddy & Jonathan Cheng, *Markets Sink Then Soar After Fed Speaks: Pessimism Melts After Traders Parse Statement; Biggest Down Rise Since '09,* Wall Street Journal, Wednesday, August 10, 2011, at A1.

[62] *See* U.S. Department of Treasury, Daily Treasury Yield Curve Rates, http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield (visited September 9, 2011).

[63] *See, e.g.*, Value Line, Electric Utility (East) Industry, August 26, 2011 at p. 137:

> During these volatile times, investors tend to seek out safe havens for their money, which as far as equities are concerned, usually leads them to the utility sector. The industry's relative stability has been highlighted considerably over the past twelve months. Year-to-date, the Value Line Utility Average has remained relatively flat, rising a modest .3%, while the Value Line Geometric Average is down 12.1%.

[64] *See* response to Question No. 2 above.

[65] Paul Carlsen, *S&P's Government Cut Impacts Some Utility Debt But Sector Stocks Outperform Volatile Markets*, Electric Utility Week, August 15, 2011, at 13 ("Power sector stocks outperformed the wildly volatile overall markets in the wake of Standard & Poor's Ratings downgrade of the US government late August 5.")

[66] *National Grid*, D.P.U. 09-39 at 400 (2009), *available at* http://www.mass.gov/Eoeea/docs/dpu/electric/113009dpuordng.pdf.

National Grid (Narrangansett)	11.14 (2006)	9.80 (RI 2010)[67]
Northeast Utilities (WMECo)	11.14 (2006)	9.60 (MA 2011)[68]
Northeast Utilities (CL&P)	11.14 (2006)	9.40 (CT 2010)[69]
United Illuminating	11.14 (2006)	8.75 (CT 2009)[70]
Northeast Utilities (PSNH)	11.14 (2006)	9.67 (NH 2010)[71]
Green Mountain Power	11.14 (2006)	9.45 (VT 2010)[72]
Central Maine Power	11.14 (2006)	9.80 (ME 2008)[73]
PSEG	11.18 (2008)*	10.30 (NJ 2010)[74]
Constellation Energy (BG&E)	11.30 (2006)*	9.86 (MD 2010)[75]
Pepco Holdings	11.30 (2006)*	9.83 (MD 2010)[76]
Exelon (Commonwealth Ed)	11.00 (2008)*	10.50 (IL 2011)[77]

[67] *Narragansett Electric Co., d/b/a National Grid*, R.I. P.U.C., Docket No. 4065 at 92 (2010), *available at* http://www.ripuc.org/eventsactions/docket/4065-NGrid-Ord19965A%284-29-10%29.pdf.

[68] *Western Massachusetts Electric Co*., D.P.U. 10-70 at 280 (2011), *available at* http://www.env.state.ma.us/dpu/docs/electric/10-70/13111dpuord.pdf

[69] *Connecticut Light & Power Co*., CT D.P.U.C., Docket No. 09-12-05 at 115 (2010), *available at* http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/f630442888d36776852577520055066a?OpenDocument.

[70] *The United Illuminating Co*., CT D.P.U.C., Docket No. 08-07-04 at 106-107 (2009), *available at* http://www.dpuc.state.ct.us/FINALDEC.NSF/0d1e102026cb64d98525644800691cfe/3b76f3e31c22cb19852575cb005cea73?OpenDocument

[71] *Public Service Company of New Hampshire*, NH P.U.C., Docket No. DE 09-035 at 33-34 (2010) (approving a settlement agreement), *available at* http://www.puc.nh.gov/Regulatory/Orders/2010orders/25123e.pdf.

[72] *Green Mountain Power*, VT PSB, Docket No. 7673 (2010) (PSB approved GMP's proposed ROE set forth in its July 30, 2010 filing without discussion), *available at* http://psb.vermont.gov/sites/psb/files/orders/2010/7673OrderClosingOrder.pdf.

[73] *See Central Maine Power Co., Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirements and Rate Design, and Request for Alternative Rate Plan*, No. 2007-215, Order Approving Stipulation (Me. P.U.C. July 1, 2008); *Central Maine Power Co., Chapter 120 Information (Post ARP 2000) Transmission and Distribution Utility Revenue Requirements and Rate Design, and Request for Alternative Rate Plan*, No. 2007-215, Bench Analysis, (Me. P.U.C. September 14, 2007).

[74] *Public Service Electric & Gas Co*., NJ BPU, Docket No. PUCRL-07599-2009N at 9 (2010), *available at* http://www.state.nj.us/bpu/pdf/boardorders/2010/6-7-10-2H.pdf.

[75] On December 6, 2010, the Maryland Public Service Commission ("PSC") issued an "abbreviated order" authorizing BGE to increase its distribution rates with a 9.86% rate of return on equity. *Baltimore Gas & Electric Co*., MD P.S.C., Docket No. 9230 at 4 (2010), available at http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\CaseNum\9200-9299\9230\78.pdf .

[76] *Potomac Electric Power Co*., MD P.S.C., Docket No. 9217 at 58 (2010), *available at* http://webapp.psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\CaseNum\9200-9299\9217\105.pdf.

Progress Energy Florida	10.8 (2007)*	10.50 (FL 2010)[78]

** Base ROE determined by FERC-approved settlement.*

As the table illustrates, more recently-established state-approved ROEs generally are lower than Commission-allowed ROEs that were established prior to the financial crisis and remain in effect. While the theory behind granting transmission rate incentives is that they are required because transmission projects must compete with other investment opportunities available to utilities, transmission projects will face little internal competition for capital investments from distribution projects when even base ROEs for transmission exceed retail ROE allowances. Accordingly, in evaluating whether incentives are necessary to support needed investment in transmission, the Commission should consider whether lower ROE allowances for retail services already enhance the attractiveness of transmission investment. Furthermore, layering ROE adders on top of a base ROE that is overly-generous because it has not been updated to reflect current market conditions will unreasonably inflate transmission revenue requirements.

Q9: How should the Commission best balance the promotion of transmission investment with the assurance of just and reasonable rates?

The Commission retains discretion to mix incentives and penalties to promote timely and cost-effective transmission investments and should do so to protect consumer interests. In Order No. 679-A, the Commission found that FPA Section 219 did not rule out symmetrical approaches to return or performance based rates.[79] Thus, while it has not, to date, linked eligibility to incentive awards to the applicant's agreement to accept penalties for non-performance, the

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[77] *Commonwealth Edison Co.*, IL CC, Docket No. 10-0467 at 153 (2011), *available at* http://www.icc.illinois.gov/docket/files.aspx?no=10-0467&docId=166950.

[78] *Progress Energy Florida, Inc*., FL PSC, Docket No. 090079-EI at 95 (2010), *available at* http://www.psc.state.fl.us/dockets/orders/singleDisplay.aspx?orderNumber=PSC-10-0131-FOF-EI.

[79] Order No. 679-A at P 130.

Commission could – and should – require greater symmetry for certain types of incentive treatment consistent with Order No. 679.

In 1992, the Commission issued an Incentive Rates Policy Statement.[80] What the Commission said there about regulatory symmetry is as true today as it was in 1992:

> Incentive mechanisms should be designed to reward utilities that succeed in reducing costs, expanding services, and streamlining operations. At the same time, incentive regulation should be designed to penalize utilities that fail to achieve these efficiencies – opportunities for reward should be offset by a symmetric downside risk.[81]

Joint Commenters recognize that, in some circumstances, it may be appropriate to grant incentive rate treatment for transmission projects in the form of abandoned plant cost protection. This type of rate treatment significantly reduces project risks. If it serves to make an otherwise too risky project feasible, then it also seems reasonable that, in return for this protection (*i.e*, to make the incentive more symmetrical) the applicant should be required to forego an incentive-based return allowance if the project is in fact constructed.

In several recent cases, the Commission has granted applicants incentive rate treatment for new transmission facilities even where the applicant acknowledged that it did not qualify for incentive rate treatment under Section 219 of the FPA and Order No. 679.[82] The Commission has the authority to grant incentives, it correctly noted, independent of Section 219, something it observed in Order No. 679.[83] But while the Commission has the authority to grant incentive rates for new transmission facilities outside of Order No. 679, Joint Commenters strongly urge

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[80] 1992 Policy Statement, *supra.*

[81] *Id.* at p. 61,590.

[82] *See, e.g., Southern California Edison Co.*, 133 FERC ¶ 61,108 (2010), *reh'g denied*, 133 FERC ¶ 61,254 (2010) ("*SoCal Edison*").

[83] *SoCal Edison*, 133 FERC ¶ 61,208 at P2; *see, e.g., Pacific Gas & Elec. Co.*, 123 FERC ¶ 61,067, at P 32 (2008) (citing Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21 n.37); *Southern California Edison Co.*, 133 FERC ¶ 61,107 (2010), *reh'g denied*, 133 FERC ¶ 61,255 (2010).

the Commission to eschew the "public policy" grounds it invoked in *SoCal Edison* and instead employ in such cases the fully developed standards established in its still extant and well-reasoned 1992 Incentive Rates Policy Statement. There are several reasons for doing so.

First, Order No. 679 and FPA Section 219 were the tools chosen by Congress and the Commission to encourage new transmission construction. Order No. 679 *liberalized* the Commission's existing incentive rate policy. Yet, in *SoCal Edison, where the applicant could not meet the Commission's generous Order No. 679 policy*, the Commission relied on its general authority under Section 205 to grant incentive rate treatment to the applicant based on a "combination of policy reasons" – an amorphous, nearly standardless approach that could be used to justify incentive rate treatment virtually any time the Commission is so inclined.[84]

Second, apart from the absence of predictable standards, this approach to invoking general public policy grounds is of questionable legality. While terms such as "just and reasonable" and "public interest" found in the FPA are general in nature, as the Supreme Court concluded in *National Association for the Advancement of Colored People, et al. v. FPC*, Congress's direction to the Commission to act in furtherance of the "public interest" under the FPA "is not a broad license to promote the general public welfare."[85]

Finally, there is already an incentive rate policy in place where Order No. 679 does not apply, and it is well-suited to address individual requests for incentive rate treatment. The Commission's 1992 Policy Statement, as previously noted, contained two features particularly appropriate where an applicant for transmission rate incentives cannot meet Order No. 679 standards, but nonetheless seeks incentive rate treatment: (1) the requirement that incentive rate mechanisms be symmetrical (*i.e.*, that they offer both upside rewards to applicants *and* downside

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[84] *SoCal Edison*, 133 FERC ¶ 61,208 at P 2.

[85] 425 U.S. 662, 669-70 (1976).

risks for poor performance); and (2) the requirement that applicants quantify – at least in some way – the benefits to ratepayers if the incentive payment is awarded. [86]

Q10: Do the rebuttable presumptions established in Order No. 679 serve as appropriate bases for satisfying the statutory threshold for section 219(a)?

In Order No. 679, the Commission declined to make approval of a project through a regional transmission planning process an absolute prerequisite for incentives.[87] In a number of subsequent specific cases, however, the Commission has conditioned preliminary awards of incentives on subsequent approval of a project in an ISO/RTO transmission planning process.[88] Conditioning an award of incentives on project approval in an open and transparent regional transmission planning process both reinforces participation in regional planning and provides greater assurance that projects receiving incentives will deliver ratepayer benefits. On the other hand, while approval or acceptance of a project in a regional plan is a necessary condition for receipt of incentive rate treatment, many projects receiving such approval are routine in nature. Hence, their approval should not automatically qualify such projects for incentive rate treatment.

Joint Commenters, therefore, urge the Commission to adopt as a general policy that acceptance or approval of a transmission project under a Commission-approved regional planning process is a relevant, but not necessarily *sufficient* condition in order to receive incentives. If a project receives approval prior to submission of the request for incentives to the Commission, depending on the nature of the applicable planning process, it is reasonable to apply a rebuttable presumption that the project will meet the statutory standard of improving

[86] 1992 Policy Statement, 61 FERC ¶ 61,068 at p. 61,590.

[87] Order No. 679 at P 58.

[88] *Central Maine Power Co.*, 125 FERC ¶ 61,182 (2008), *requests for reh'g dismissed*, 129 FERC ¶ 61,153 (2009), *reh'g denied*, 135 FERC ¶ 61,236 (2011); *Green Energy Express LLC*, 129 FERC ¶ 61,165 (2009), *reh'g denied*, 130 FERC ¶ 61,117 (2010); *So. Cal. Edison Co.*, 129 FERC ¶ 61,246 (2009), *order on compliance filing and granting partial rehearing*, 133 FERC ¶ 61,108 (2010), *order denying request for clarification or reh'g*, 133 FERC ¶ 61,254 (2010).

reliability or reducing the cost of delivered power.[89] But, as currently provided in Order No. 679-A, the applicant should be required to demonstrate that these considerations were part of the planning process to qualify for any such presumption.[90] The presumption could be rebutted if, for example, a project was approved under the regional transmission planning process based upon considerations other than enhancement of reliability or reduction in the cost of delivered power. Similarly, if the project's expected cost at the time it was presented to the planning group was substantially lower than at the later time when the incentive rate treatment was sought, the presumption that the project would lower delivered power costs would be also be rebutted.

If the project developer submits the request for incentives prior to review and approval under a Commission-approved regional transmission planning process, while the conditional grant of incentive rate treatment should not be precluded, the applicant should face a high hurdle. At a minimum, the applicant should be required to demonstrate, as stated in the Joint Commenters' earlier response to Question No. 6: (1) an expected measurable benefit (in the form of increased reliability and/or lower delivered power costs) to consumers that is likely to be realized if the specific incentive is granted; (2) that there is a causal relationship between each incentive sought and the consumer benefits to be derived from the project; and (3) that the benefits expected materially outweigh the costs of the requested incentives. The Commission should further condition any preliminary grant of incentives on subsequent approval under the relevant regional transmission planning process accompanied by evaluation of the effects of the

[89] A region, for example, might limit evaluation of projects that are approved for the regional plan and resulting cost allocation to those that improve reliability, leaving transmission providers, including merchant transmission companies, to develop efficiency-enhancing projects outside of the regional plan. If, on the other hand, the regional planning process evaluated both reliability and efficiency projects it would be reasonable to require approval in a regional plan as a precondition to apply for incentive rate treatment.

[90] Order No. 679-A, at P 49.

project on reliability and the cost of delivered power and a determination that the project either will enhance reliability or reduce the cost of delivered power and that the costs of the incentives, in fact, are materially outweighed by the benefits. If a project is reviewed under a regional transmission planning process and rejected, then the Commission should not allow incentives.

The Commission has recognized that participation in robust and comprehensive regional planning is essential to cost-effective development of transmission.[91] The framework summarized above appropriately will apply the incentives policy to encourage such participation.

As noted above, approval of a project as part of a regional planning process should not itself qualify the applicant to receive transmission rate incentives; in some regions, like New England, such approval carries with it benefits (*e.g.*, abandoned plant cost recovery) that may obviate the reason for rate incentives. In other regions the planning process may give inadequate attention to the costs of alternatives. But the limitations of individual regional planning processes notwithstanding, conditioning incentives on approval in a regional planning process can enhance the probability that the project will deliver benefits to ratepayers sufficient to justify the incentives. If a project is not evaluated under a regional transmission planning process (whatever its shortcomings), there is no basis for comparing the asserted benefits of the project with benefits that would be available under potential alternatives.

Q 11: Are there other criteria that the Commission should adopt as additional rebuttable presumptions for satisfying the statutory threshold for section 219(a)?

Joint Commenters urge the Commission to adopt a rebuttable presumption that the granting of return-enhancing incentives (*e.g.,* ROE adders and use of a hypothetical capital

[91] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 421-25 and n.232, *order on reh'g*; Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*; Order No. 890-C, 126 FERC ¶ 61,228 (2009); Order No. 1000 at P 2 ("the Commission concludes that the reforms adopted herein are necessary for more efficient and cost-effective regional transmission planning.").

structure), is not appropriate in conjunction with the granting of risk-reducing incentives (*e.g.*, the recovery of abandoned project costs and the allowance of CWIP in rate base). The presumption should be rebuttable only where the applicant demonstrates that there are extraordinary risks associated with the project that cannot be mitigated by risk-reducing incentives.

Q 12: What types of information, data, or studies should the Commission consider in evaluating whether an applicant has made an independent showing that satisfies section 219(a)?

If a project has not been accepted under a Commission-approved regional transmission planning process prior to submission of the request for incentives, the Commission should require: (1) a detailed engineering assessment of the project's impacts on transmission system reliability demonstrating that the project will not harm but will enhance reliability; and (2) a comparative analysis demonstrating that the proposed project is likely to reduce the cost of delivered power. The cost impact analysis should reflect the full estimated cost of the proposed project, including the impact of any proposed return-enhancing incentives. The Commission should not accept generalized assertions of positive impacts on reliability or congestion as sufficient satisfaction of the Section 219 statutory standards.

Q 13: Would it assist applicants if the Commission established a procedure that applicants may follow to make such an independent showing? If so, what should be the characteristics of that procedure?

It would likely assist applicants and other interested parties if the Commission established standards and/or templates for the engineering assessment and cost analysis described above. Joint Commenters suggest that the Commission convene technical conference procedures to develop such standards and templates.

Q 14: In some cases, when an applicant has sought incentives, the Commission has conditionally approved the request subject to the project receiving approval in a regional transmission planning process or state siting process. [Note: These processes are related to satisfying the rebuttable presumptions set forth in Order No. 679.] Intervenors in various rate proceedings have raised concerns that a project scope may change in the planning and siting process. In light of this, how should the Commission balance the value of and need for the requested incentives in promoting project development and financing with the potential uncertainty surrounding project scope?

Substantial modifications in the scope of a project may result in significant changes in the impact of the project on reliability or the project's effect on the cost of delivered power. The Commission should require a project sponsor to file with the Commission a notification if the scope of a project changes significantly after the Commission has made a determination to grant incentives, including a conditional grant of incentives. Such notification should describe in detail the changes in the project and the anticipated consequences of those changes for the project's effects on reliability and/or cost of delivered power. In response to any such notification, the Commission should establish procedures to allow interested parties to evaluate and comment on the impacts of the changes in the project on the project's satisfaction of the statutory prerequisites for incentives. Based on the notification of changes to the project and the comments submitted by interested parties, the Commission should reevaluate the appropriateness of incentives in light of the reported changes. Although this reevaluation may give rise to some uncertainty regarding the continued availability of incentives, it would be inconsistent with the statutory standards to permit developers to receive incentives granted on the basis of an original project description for a substantially modified project. Absent a reevaluation, a developer could apply for incentives based upon an effectively hypothetical project. A modified project should retain incentives only if it remains likely to deliver the anticipated benefits relied upon to justify the original award of incentives.

Q 15: Pursuant to section 219(b)(1), what steps could the Commission take to "promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce"?

The Commission should support the use of open and transparent regional planning processes, and the thorough evaluation of all potential alternatives. Incentives, when granted, should tie the efficient construction and completion of projects to the incentives authorized.

As noted above in response to Question No. 10, in Order No. 679, the Commission declined to make approval of a project through a regional transmission planning process an absolute prerequisite for incentives, but has since conditioned preliminary awards of incentives in a number of cases on subsequent approval of a project in an ISO/RTO transmission planning process. Conditioning an award of incentives on project approval in an open and transparent regional transmission planning process both reinforces participation in regional planning and provides greater assurance that projects receiving incentives will deliver ratepayer benefits.

The core policy challenge before the Commission is to ensure that needed infrastructure is built in a cost effective manner. Open and transparent planning processes provide greater indication of the relative benefits of a proposed transmission project prior to the granting of transmission rate incentives for such a project. But actions must be taken to assure that a project, once approved, is constructed in a cost effective manner. Granting income enhancing rate incentives on cost overruns is contrary to such a policy. Instead, incentives should be used to promote cost efficiencies and minimize perverse incentives favoring cost overruns.

Q 16: How would these steps affect other aspects of the Commission's rate-making policy?

See Response to Question No. 17.

Q 17: Pursuant to section 219(b)(3), what steps could the Commission take to "increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities"?

Joint Commenters submit that, where the regional planning process evaluates both reliability and efficiency-enhancing projects, any grant of incentives should only be considered after a project has been approved through that regional planning process.[92] When such an evaluation is made, the Commission would be in a better position to understand and evaluate the basis for granting incentives for new infrastructure. This thorough analysis and evaluation of potential alternatives could also assist the Commission in determining what are "routine" upgrades that should not be considered for incentives.

Joint Commenters further agree that there is a need for new transmission infrastructure. In one typical scenario, areas that have high electric usage but lack adequate generation become what are called "load pockets." Because these areas are generation-deficient (as often the case in highly-congested urban areas), existing transmission lines that bring power into these areas are prone to overloads. Thus, the potential for reliability issues and increased congestion costs arise if one or more of these existing lines are unavailable. There are, however, other ways besides just building new transmission lines to address these potential reliability issues and the related congestion costs created by load pockets.

In simple terms, if the demand for electricity within a load pocket exceeds the available supply of electricity, one of two things must happen in order to keep the system in balance – supply must go up or demand must go down. Increasing the supply of power involves building more generation facilities within the load pocket, adding adequate storage facilities within the load pocket, or building new transmission lines to deliver additional power supplies into the load

[92] *See also* Response to Question No. 10.

pocket. Reducing demand involves some form of demand side management, such as energy efficiency/conservation measures or demand response programs. Of course, any combination of these strategies can be implemented to achieve the desired result of keeping supply and demand in balance. Hence, the construction of new transmission facilities may be an effective means to address the supply/demand equation but it may not always be the most efficient means to do so.

Joint Commenters are not suggesting that the Commission has jurisdiction to order transmission providers to engage in integrated resource planning. Transmission planning processes, however, should take into account state, local, and regional policy mandates in these policy areas. Where the relevant planning process does incorporate these features, the analysis can inform the Commission's determination of whether a particular transmission project resulting from such a planning process is worthy of a grant of incentives.

Q 18: As indicated above, applicants must show that their project meets the threshold under section 219(a). What showing should the Commission require to support a request for incentives under section 219(b)(1) and (b)(3)?

The Commission should require applicants to show that the project in question is not a project that the applicant was already planning (or required) to undertake. Applicants should also be required to show that their existing transmission infrastructure has been maintained and upgraded over time in an appropriate manner, so that the project in question is not needed to compensate for past failures adequately to maintain existing infrastructure. Applicants should not be allowed to collect incentives to remedy past deficiencies in their transmission building programs.

Q 19: Does the focus of the nexus test on the risks and challenges of a given transmission project remain appropriate for the purpose of justifying incentives? Is that focus more appropriate for some incentives than others? What other factors should the Commission consider?

The question assumes continued application of the Commission's nexus test, presumably in its current form. As noted in response to prior questions, Joint Commenters believe that test is insufficiently rigorous and hence fatally flawed in both concept and execution.

The ultimate objective of Section 219 of the FPA is to benefit consumers through increased reliability or lower delivered power costs (resulting from reduced congestion). The Commission must develop a more rigorous test, one that demands proof from applicants that: (1) the incentives they seek are needed to produce tangible benefits; (2) that there is a causal relationship between the incentives sought and the benefits expected; and (3) that the benefits will materially exceed the expected costs of the project. A showing that the risks and challenges of a given project are out of the ordinary should be a prerequisite for seeking incentive rate treatment. A requirement that the focus be on the expected benefits of the project and the relationship of those benefits to the expected costs of project (including the costs of the incentive rate treatment), as this Commission said many years ago, is not too much to demand of applicants:

> The Commission remains convinced that benefits to consumers must be quantifiable even though the task is admittedly a difficult one. All 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. "Projected cost of service" simply means an annual estimate of the cost of service that the utility would otherwise expect to incur during the effective time period of its incentive rate proposal. If the utility proposed a five-year period, it would be required to include in its application with the Commission a comparison of expected incentive rates to the expected cost of

> service rates that it would otherwise propose to base its rates under traditional ratemaking.[93]

Referring to the analogous issue of incentive rates to encourage new natural gas production, the United States Court of Appeals for the District of Columbia Circuit observed that "[t]his principle has been stated in a number of ways: that there must be a 'quid pro quo' for the extra funding; that there must be an 'inquiry into the incremental increase in . . . supply' attributable to the program; and that there must be 'symmetry' between the funding and increase in production."[94] Such showings are not too much for consumers to ask of this Commission; in fact, such showings are required to ensure rates are just and reasonable.

Q 20: Would focusing on project characteristics or effects be a more effective means than focusing on a project's risks and challenges as the basis for granting incentives? What characteristics or effects would be appropriate for the Commission to consider for that purpose, consistent with section 219? For example, this could include transmission projects that are multi-state or high voltage in nature.

The short answer is that the applicant should be required to demonstrate *both* risk and beneficial effect – and a causal relationship between the incentives requested and the decision to undertake the project. Focusing on the risk of a project divorced from the benefits it is expected to produce is counterproductive. A high risk (or high voltage) project that cannot be shown to produce net benefits to consumers should not be granted incentive rate treatment. Conversely, a beneficial, low risk project should not be entitled to incentive rate treatment either. Transmission owners should not be rewarded for taking routine risks or for doing their job of providing quality service.

[93] 1992 Policy Statement, 61 FERC ¶ 61,168 at p. 61,590 (internal citations omitted).

[94] *Pub. Serv. Comm'n of New York v. FERC*, 589 F.2d 542, 553 (D.C. Cir. 1978) (footnotes omitted).

Q 21: What risks and challenges are transmission developers facing today? Have such risks and challenges evolved since the issuance of Order No. 679, and if so how?

As noted in response to previous questions, the financial environment facing transmission developers has fundamentally altered since the issuance of Order No. 679, due in large part to the economic recession that commenced in 2008. Simply put, investors are looking for conservative infrastructure investments paying a consistent and safe rate of return. Transmission infrastructure investments fit that bill. The money to finance them is available assuming that impediments to siting and constructing transmission can be overcome.

Q 22: Is the distinction between a routine and non-routine project in analyzing "risks and challenges" useful in providing guidance to the industry on how to apply the nexus test? Does this distinction appropriately differentiate between the level of difficulty in constructing various transmission projects?

The question assumes the continued usefulness of Order No. 679's nexus test. That test, as noted in Joint Commenters' responses to prior questions, is insufficiently rigorous. Applicants should be required to demonstrate that the incentives they seek are necessary to the successful completion of needed transmission projects.

The distinction between routine and non-routine investments, however, is still useful in that it would be a rare case in which incentive rate treatment would be appropriate for a routine project. To be sure, the distinction between routine and non-routine projects will still require differentiation among non-routine projects, some of which may warrant greater incentives than others. But requiring the applicant to demonstrate that the specific incentive(s) sought are needed for a particular project allows the Commission to consider the facts of each particular case in deciding whether incentive rate treatment is justified, and, if so, what type of incentive is appropriate. This issue is discussed in greater detail in the Joint Commenters' response to Question No. 34.

Q 23: What types of criteria should the Commission consider when evaluating the "scope of a project" or the "effect of a project," in determining whether a project is routine or non-routine? Should the Commission establish bright line criteria, such that a project meeting those criteria is non-routine regardless of the applicant, or should this evaluation depend on the circumstances of the applicant, e.g. the estimated cost of the project relative to the applicant's transmission rate base?

It bears emphasis, as Mr. Tracy notes, that in "the vast majority of cases," no special rate treatment is needed – "most transmission projects are routine and even large undertakings are part and parcel of the responsibilities of electric utilities."[95] If a project is one the transmission provider is obligated to build, either by contract or public utility obligation, the presumption should be that such a project is routine. That presumption comports with the Commission's observation that it is prudent for transmission providers to plan for new transmission to meet reliability needs or to consider upgrades that would reduce delivered power costs.[96] The presumption here proposed creates a workable "bright line criterion" by which to assess applications for incentive rate treatment, but does not preclude the applicant from demonstrating that some incentive rate treatment may nonetheless be necessary. This type of "bright line criterion" would apply to all applicants for incentive rate treatment, but it does not mean that the same project would necessarily be routine for any applicant. As discussed more fully in response to Question No. 34, what is or is not routine would be determined on a case-by-case basis. A principal indicator that a project is routine would be that it is part of the particular transmission provider's core business obligations.

[95] Tracy Statement at P 12.

[96] Order No. 1000 at P 83.

Q 24: Are there aspects of the Commission's accounting and ratemaking policies, including the use of formula rates, that reduce or increase the risks and challenges of a transmission project? If so, how should the Commission take into account the effect of its accounting and ratemaking policies in evaluating incentive applications?

The Commission has (correctly) noted that the use of formula rates can mitigate the risk of regulatory lag by expediting recovery of the costs of new transmission construction through rates and associated cash flow improvement.[97] As the Commission explained in *Indiana and Michigan Power Co*., a cost-of-service tariff:

> Permits immediate recovery of any increase in costs, thus limiting [the utility's] risk and minimizing not only the risk of regulatory lag, but also the risk of disapproval. It will automatically make its allowed rate of return on equity regardless of whether it delivers the power or not. The steady stream of revenues from such an arrangement provides the company with a very real advantage over those utilities not operating under similar cost-of-service tariffs.[98]

This risk factor, the Commission has held, justifies a lower return allowance.[99] For this reason, in those instances in which the Commission has permitted or may permit the use of formula rates,[100] their use must be considered a factor offsetting the need for other incentives.

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[97] *See, e.g*., *Northeast Utilities Service Co. (Re Public Service Company of New Hampshire),* 56 FERC ¶ 61,269 at p. 62,053 (1991); *Indiana & Michigan Power Co.*, 4 FERC ¶ 61,316 at p. 61,739 (1978); *South Carolina Generating Co.*, 40 FERC ¶ 61,116 at p. 61,311 (1987).

[98] *Indiana & Michigan Power Co.*, 4 FERC ¶ 61,316 at p. 61,739.

[99] *Id*.

[100] By noting that formula rates have been recognized as a risk reducing benefit to transmission owners, Joint Commenters do not thereby intend to suggest that they endorse the use of formula rates generally or in specific instances.

Q 25: In Order No. 679-A, the Commission stated that "[i]n general, we do not consider that contractual commitments or mandatory projects, such as section 215 reliability projects, disqualify a request for incentive-based rate treatment. Provided applicants are able to demonstrate they meet the requirements of section 219, including establishing the required nexus between the requested incentive and the investment, they may qualify for incentive-based rate treatments. A prior contractual commitment or statute may have a bearing on our nexus evaluation of individual applications." [Footnote omitted.] Is the existence of a contractual commitment to build a relevant factor in considering applications for rate incentives?

Joint Commenters believe the answer to this question is a resounding "yes." The relevance of a contractual commitment to build transmission facilities should be self-evident. The Commission itself has in the past held that denying incentive rate treatment to utilities for undertaking what they are already obligated to do is in the public interest.[101] Similarly, the Commission recently stated in Order No. 1000 that "when conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to plan for transmission needs driven by Public Policy Requirements."[102] Given that it would be imprudent not to build needed transmission and that a public utility could be sued for breach of contract if it did *not* build transmission it was obligated to construct, the question is not whether existence of a contractual obligation is relevant, but rather, why should any incentives be granted for complying with contract obligations? There is little reason to believe that incentive rate treatment would "make a transmission owner try harder or work faster to complete a project" it is already obligated to build.[103] Indeed, as noted elsewhere in these comments, the Commission's current policies, by

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[101] *See, e.g.*, *New England Power Pool*, 97 FERC ¶ 61,093 at 61,477 (2001) ("This decision is in the public's interest as it does not unjustly reward NEP for doing what it is supposed to do.").

[102] Order No. 1000 at P 83.

[103] Mertens Statement at P 7.

awarding transmission rate incentives based on ultimate project costs, may actually retard their deployment if delay will increase project costs and hence the awarded return.[104]

In Order No. 679-A, the Commission acknowledged that an obligation to build would be a relevant factor in evaluating an application for incentive rate treatment, but it declined to find that an obligation to build a project should disqualify an applicant from eligibility for incentives.[105] Just two months ago, the Commission, over Chairman Wellinghoff's dissent, interpreted its pronouncement in Order No. 679-A as stating only that the existence of a contractual obligation to build "*could* be" relevant to an application for incentive rate treatment.[106] It rejected the transmission owner's contractual obligation as a factor on the ground that the challenging parties had not demonstrated why a contractual obligation to build was relevant.[107] Joint Commenters urge the Commission to abandon this approach and recognize that the existence of a contractual obligation to build is a critically relevant factor warranting a decision that the award of transmission rate incentives is inappropriate.

Q 26: The Commission has encouraged the joint ownership of transmission facilities but declined in Order No. 679 to make it a requirement for receiving incentives. [Footnote omitted.] Does this approach adequately account for the benefits of joint ownership? Are there other approaches to providing incentives that encourage joint ownership of transmission facilities?

As Mr. Tracy notes in his attached Statement, "one of the reasons frequently given by applicants for incentive rate treatment under Order No. 679 is that the project's large cost in relation to the utility's existing rate base creates cash flow problems and other substantial

[104] *Id*. at P 7.

[105] Order No. 679-A at P 122.

[106] *Northeast Utilities Service Co. and National Grid USA*, 135 FERC ¶ 61, 270 at P 19 (2011).

[107] *Id*.

risks."[108] "Joint ownership of a transmission project," he explains, "diversifies the risk of the undertaking and may obviate the need in whole or in part for transmission incentives."[109] Accordingly, Joint Commenters urge the Commission to require an applicant for incentive rate treatment to demonstrate: (1) that it has considered joint ownership; and (2) why joint ownership either was infeasible or would not suffice to overcome the risks associated with the development of a project.

Q 27: Are there specific criteria the Commission should use in evaluating whether and how to adjust certain incentives to account for the impacts of other incentives?

Joint Commenters believe that return-enhancing incentives generally should not be permitted where the applicant can demonstrate that it should qualify for risk-reducing incentive rate treatment. This issue is addressed more fully in response to Question Nos. 28 and 34.

Q 28: Do certain incentives sufficiently mitigate the risks and challenges of a transmission project so as to obviate the need for granting other incentives, or warrant adjustment in the level of those incentives? For example, should granting 100 percent CWIP and recovery of the costs of abandoned plant affect the evaluation of a request for an incentive ROE adder based on a project's risks and challenges?

The short answer to the Commission's question is yes. As detailed in the attached statements of Mr. Tracy, Mr. Behrns, and Mr. Mertens, risk-reducing incentive rate treatments such as abandoned plant protection and/or CWIP would obviate the need for return-enhancing incentives. This issue is addressed more fully below in response to Question No. 34.

Q 29: Should the Commission limit the application of incentives to the cost estimate utilized for including or retaining the project in the plan submitted through the regional planning process? If so, which incentives should be applied to the cost estimate, and which should be applied to all prudently incurred costs?

The answer to the first part of Question No. 29 is generally, yes. But Joint Commenters would modify the policy slightly to require that the incentives apply to the cost estimate in

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[108] Tracy Statement at P 25.

[109] *Id*.

existence at the time the applicant seeks incentive rate treatment from the Commission. As Mr. Mertens recommends in paragraph 11 of his Statement "there may be several stages in a regional planning process at which revised estimates of a project's cost are submitted. These differences become irrelevant if the Commission's policy is to limit the applicant to enhanced returns based on the estimates of project costs in existence at the time the applicant seeks incentive rate treatment."

As to the second part of the Commission's question, Joint Commenters assume that the only incentive rate treatment to which this question is relevant is the rate of return adder. In that regard, the adder should only apply to the estimated cost of the project. As explained directly below, no incentive adder should apply to any portion of actual costs that exceed the estimate, regardless of whether the costs incurred by the applicant were prudent.

The central purpose of the Commission's incentive rate policies under Order No. 679 is to encourage transmission providers to construct new and innovative transmission projects to improve reliability and reduce the cost of transmission congestion to benefit ratepayers in a timely and efficient manner. The nexus test under that Order, if properly applied, would obligate applicants to tailor their incentive requests to those objectives. In the years since adoption of Order No. 679, however, the Commission has allowed every transmission provider granted ROE adders the right to apply these adders to the ultimate costs of their projects, not the costs estimated at the time they applied for the adders. If actual project cost never deviated substantially from the applicant's estimates, this fact would be largely irrelevant. But the reality is that the actual costs of transmission projects in recent years have routinely, and in many cases, dramatically exceeded the prior estimates of project sponsors – even though project estimates will themselves ordinarily include a significant contingency factor to account for the uncertainty associated with cost estimation. The result is that consumers have been required to pay millions of extra ROE dollars because the ROE adders have been applied to these very large cost overruns.

There are, logically, only three explanations for transmission project costs to exceed estimates: (1) that the cost increases were the result of circumstances beyond the transmission developer's control; (2) that the transmission developers intentionally understated those costs; or (3) that the transmission developers in good faith underestimated the project costs. But in each case, as discussed below, the application of the adder to the ultimate project cost rather than the applicant's estimate is either counterproductive or, *at best*, unnecessary. Joint Commenters discuss each possibility in turn.

To be sure, increases in transmission costs from original estimated levels are often outside the control of the project sponsors. One such example would be changes in construction costs that result from unanticipated changes in regional labor markets.[110] Changes in material costs are likewise influenced by unpredictable fluctuations in global demand for those materials. But allowing the adder to apply to cost increases attributed to these factors irrationally rewards the transmission developer for doing nothing. In Order No. 679 terms, there is no nexus between the application of the adder and the result to be achieved. And worse, applying the adder to the project's actual, higher cost creates a *disincentive* for the transmission developer to ascertain whether a cost is truly beyond its ability to control. If costs exceed projections, the sponsor will earn the adder on the cost overrun.[111] Indeed, to the extent the adder is intended to encourage

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[110] Tracy Statement at P 22.

[111] Behrns Statement at P 11. As Mr. Behrns there states:

> In my experience there is a range of utility conduct that would be considered prudent by regulators. But within this range, the utility has considerable discretion in its business decisions. If utility management knows that it will be allowed a higher return on the costs of

timely completion of projects, applying it to actual project costs creates the opposite incentive. If construction or materials costs are rising through circumstances beyond the applicant's control, the applicant will actually have the incentive to delay project completion and benefit from application of the adder to the now-higher rate base.

Take next the case where the project costs were intentionally understated. Such an underestimate would have unfairly biased the transmission planning decision in favor of the project and against other possible alternatives made artificially to look less competitive and hence uneconomic. The transmission owners should not be rewarded with an incentive adder in such circumstances. And while the intentional misrepresentation of project cost estimates might otherwise be punishable – *if it could be detected* – limiting the adder to estimated project costs will serve the prophylactic purpose of preventing the problem before it occurs, without denying applicants the right to seek ROE adders based on their *bona fide* cost estimates.

Finally, an honest but erroneous underestimate of the project's costs should not justify the adder either. By its terms, the project estimate represented the transmission developer's reasonable expectation as to the costs of completing the project and, under typical utility practice, the estimate also included a substantial contingency factor.[112] It is not only fair, but *logical* to assume that if there was a nexus between the adder and the transmission developer's decision to proceed with the project, it was based on the transmission developer's project cost

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> a new transmission project than the normal ROE allowance, where there is a close decision about how to proceed on a project, it will have little disincentive to choose the more expensive approach. Worse, it will actually have the incentive to take the more costly route, as long as its decision is broadly within the range of a utility's discretion. It would be unsound regulatory policy, in my opinion, to reward the utility for such a decision. Yet that is precisely the effect of a policy that would allow transmission owners to earn ROE adders on the ultimate costs of their projects.

Berhns Statement at P 11.

[112] *See* Mertens Statement at P 9.

estimates.[113] In other words, the transmission developer was prepared to proceed with the project at its projected cost. There is no rational reason to reward the transmission developer for mistakenly underestimating the project's actual cost – the entity will still earn the full base rate of return on the higher, actual project cost (assuming the cost was prudently incurred) and will also earn an incentive adder based on the capital costs it expected to incur.[114] But if the transmission developer earns an incentive adder on the cost overrun, it will be rewarded not only for undertaking the project, but for coming in over budget. An adder in this circumstance sends exactly the wrong message – not merely reducing the transmission developer's incentive to contain project costs but rewarding it for poor performance.[115]

The limitation urged here on the availability of the adder self-evidently does not impinge on reasonable shareholder expectations about the availability of the adder. Having made a good faith representation to the Commission that the developer could build a project at a certain estimated cost, including a contingency factor, and having asked for the adder based on that estimate, the transmission developer and its shareholders would not have a reasonable expectation that the company would earn the incentive adder on cost overruns.[116] Nor is it in any sense unfair to limit ROE adders in this way. First, as noted above, the Project developer will still earn the base ROE allowance on the project's actual cost, even if that cost substantially exceeds the developer's estimates (as long as the costs were prudently incurred).[117] Projects for

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[113] *Id.*

[114] Statement of Ron Behrns at PP 9-10.

[115] *Id.*

[116] *See* Mertens Statement at P 9.

[117] *Id.* at P 12. To illustrate, suppose, for example that the applicant for a transmission ROE adder estimates the cost of its project at $100 million, but the actual cost turns out to be $150 million. If the base ROE is 10% and the adder is 1%, the applicant will be allowed the 10% ROE on the $150 million

which ROE adders are sought, moreover, will usually be subject to a planning process where the estimated costs of the project, which may be competing with other projects, will influence whether it is approved. Again, the applicant should not be rewarded with an added return where the ultimate project cost, had it been known earlier, might have resulted in the planning body choosing an alternative solution.

The Commission should not underestimate the pernicious effect that tying ROE adders to ultimate project costs has on consumers. Joint Commenters recognize the need for additional transmission infrastructure. Even without transmission adders, however, the cost of transmission plant in rate base has jumped dramatically in recent years. In many regions, transmission rates have more than doubled in the middle of a recession. So if consumers are going to be asked to foot the bill for this needed expansion, they need assurances that they will be paying no more than is reasonably necessary to get needed transmission facilities built. If ROE adders remain tied to actual costs, the continuing sharp increases in project costs experienced in recent years means that the adder has become inflated and investors have been getting a windfall they were never really expecting. What was once sufficient incentive to jumpstart a project becomes a bonus for coming in over budget – a result which, by definition, had nothing to do with the positive efforts of the project sponsor. It is as if company management had voted to offer its CEO a $1 million bonus for bringing a project in on time and within budget, but promised twice the bonus if the project came in late and at double its budgeted cost.

The Joint Commenters emphasize here that their concern about cost overruns is not about the prudence of utility conduct. Public utilities are not entitled to recover imprudently incurred

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project cost, but will not be allowed the 1% adder on the $50 million by which the project's costs exceeded the original $100 million estimate.

costs, much less a *return* on rate base inflated by imprudent conduct. The concern is to eliminate the *disincentive* for cost containment inherent in granting ROE adders based on actual cost.

Q 30: How could such an approach be implemented? Would this approach work in all regions of the country? What processes for developing, evaluating, and updating cost estimates must be in place within regional transmission planning processes to facilitate such an approach?

As noted in response to Question No. 29, there is no need to update estimates if the Commission were to confine incentive adders to the applicant's estimate of project costs at the time it applies for incentive rate treatment. This approach not only avoids differences in estimating processes among regions, it comports wholly with the investment decision-making process. These points are explained in detail in the Statements of Mr. Tracy and Mr. Mertens. As Mr. Tracy states:

> Despite likely differences in the way cost estimation processes may vary from region to region, I think there is a generic approach to this problem that transcends regional differences. There may, for example, be several stages in a regional planning process at which revised or updated estimates of a project's cost are submitted. For purposes of incentive ratemaking, however, the focus should be on estimates in existence at the time the applicant seeks incentive rate treatment. At the time an applicant seeks a rate of return adder, it should include the most recent estimate of the project's cost, whether that estimate has been submitted to a regional planning organization, a siting authority or, in the absence of such filings, to its own management. Presumably, if an applicant believes an incentive ROE adder is necessary, it has likewise concluded that the revenues produced by the adder, as applied to the then-estimated cost of the project, are sufficient to undertake the project. Where the applicant then experiences actual costs that exceed its estimates, and those costs were prudently incurred, it is my understanding of conventional ratemaking that the utility would be allowed to earn its standard return on the total cost of the facilities.[118]

Mr. Mertens similarly observes:

> There are, of course, many reasons why the actual costs of a transmission project may exceed the estimated costs. Imprecision is the very nature of an estimate. But my uniform experience in the gas and electric industries is that when utilities make decisions to invest in new infrastructure projects, including transmission

[118] Tracy Statement at P 23.

> projects, they do so based on their estimates of the costs they expect to incur. Those projects are approved because they meet internal financial hurdle rates based on the same estimates that they initially advance to the FERC for approval. There may be some very limited instances in which the availability of an incentive return provides the utility with the impetus to undertake a transmission investment, but the decision to proceed is based on the estimated cost of the project and the expected return on that estimated cost.[119]

As Mr. Mertens, a former Vice President for Electric Transmission Services at Westar, added: "My experience and training leave me certain that no rational utility would turn down an opportunity to invest in a needed transmission project that allowed it a supranormal return allowance on its estimated project costs even if it were allowed only a normal return on project costs that exceed its estimates at time of approval."[120]

The reform proposed in these comments is well within the Commission's discretion. The reform proposed also tackles a problem the Commission itself recognized years ago, namely that allowing a project sponsor an ROE adder without constraints tied to cost containment means there would be no incentive to complete projects on time and within budget.[121]

One other aspect of the Commission's approach in Order No. 17 bears comment. There, the Commission sought to address the cost overrun concern, not solely by limiting the incentive to estimated costs, but by adjusting the actual rate base upward if the project's actual costs were below budget:

> In an effort to discourage cost overruns, the Commission adopted the concept of an Incentive Rate of Return (IROR), a one-time adjustment to rate base that would have the same effect as varying the allowed rate of return over the operating life of the pipeline. The adjustment would either increase or decrease the rate base attributable to equity financing, depending on whether or not the

[119] Mertens Statement at P 9.

[120] *Id*. at P 10.

[121] *Northern Border Pipeline Co.*, 52 FERC ¶ 61,102 at 61,492-93 (1990) ("*Northern Border")* (*citing* Order No. 17, *Incentive Rate of Return for Alaska Natural Gas Transportation System*, 5 FERC ¶ 61,199 (1978) ("Order No. 17")).

> project was completed within budget and on schedule. A one-time adjustment, increasing the equity component of Northern Border's rate base in the project, was made shortly after Northern Border commenced operating to reflect the fact that the project was completed under budget and on schedule.[122]

The principal concern with such an approach to cost containment is that applicants for incentive adders would then have the incentive to inflate their cost estimates so they could claim the adjustment for coming in under budget.[123] Joint Commenters, as a group, do not, therefore, endorse this approach to cost containment. But if the Commission were to consider a cost containment adjustment of this type, they are in agreement that two safeguards would need to be put in place to protect the integrity of the estimating process. First, the adjustment for coming in under budget should be limited to those projects that have been subject to, and approved by, a comprehensive, open, and transparent regional transmission planning process that gives significant weight to project costs as a criterion. Second, the adder should be limited to those instances where the applicant could demonstrate that it faced competition for construction of the project or a substitute and that this competition constrained its incentive to inflate estimates.

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[122] *Northern Border,* 52 FERC ¶ 61,102 at p. 61,492-93 (citing Order No. 17). As the Commission noted, the one-time adjustment it proposed had the same effect as varying the pipeline's return allowance. The Commission contemplated that if the pipeline project came in under budget, it would be allowed to capitalize – and thereby earn a return on – the savings. But the same result could be achieved by allowing the transmission developer to earn a somewhat higher adder when its project is completed at less than budgeted cost. The adder adjustment would produce the same level of return dollars as if the project had come in at budget. A simple numerical example illustrates how this would work. Assume that the expected cost of a project was $100 million dollars. If the project is completed at that cost the transmission owner would earn an incentive adder of $1 million. Now assume that the project is completed for $75 million. In that case, without an adjustment, the transmission owner's incentive adder would be worth $750,000. The adjustment discussed here would increase the adder from 100 basis points to 133 basis points so that the transmission owner would still have the ability to earn $1 million in adder-related revenues.

[123] Material modifications to a project that has been granted or conditionally granted incentives would give rise to similar concerns. The Commission correctly has determined that allowed or conditionally allowed incentives do not automatically apply if a project has been significantly modified subsequent to the incentives determination. Rather, in the event of substantial modifications to a project, the project developer must submit a new filing that demonstrates a nexus between the requested incentives and the features of the redesigned project and otherwise satisfies the Order No. 679 requirements. *Central Maine Power Co.*, 129 FERC ¶ 61,153, at PP 15-16 (2009), *reh'g denied*, 135 FERC ¶ 61,236 (2011).

Q 31: If a change in cost estimate is not due to the failure to contain costs but instead reflects the real cost in building the proposed transmission line, should the Commission take that consideration into account, and if so, how?

The question reflects a misapprehension about the reasons underlying the need to reform the Commission's incentive rate policy. There will inevitably be projects the costs of which exceed the applicant's original estimates, potentially for reasons wholly beyond the applicant's control. But a problem with the Commission's current policy is that it rewards transmission owners for exceeding estimates in *precisely these circumstances*. In other words, they will earn an added return simply because they did not or could not contain project costs. As Mr. Mertens explains in his statement, the applicant will base its decision whether to proceed with a project on its original estimate of project costs.[124] Allowing the applicant a return on the ultimate cost of the project gives no added impetus to the applicant, but simply bestows upon it a windfall because costs turned out higher than it expected.[125] In other words, the adder is larger, not because of the applicant's industriousness, but because of factors beyond its control. As the Commission held in *New England Power Pool,* an incentive mechanism under which the applicant "stands to gain, regardless of costs ultimately incurred," even if the added costs are not "offset with lower energy costs," is not in the public interest.[126]

There is one further problem posed by the approach suggested in the Commission's question. The question implies that return adders will continue to be granted based on ultimate project costs and that the applicants will retain such adders if they can establish, after the fact, that the costs of their projects exceeded their original estimates for good and valid reasons. But the inquiry contemplated by this approach would be counterproductive. An inherent defect in the

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[124] Mertens Statement at P 12.

[125] *Id.*

[126] *New England Power Pool*, 97 FERC ¶ 61,093 at p. 61,480 (2001).

Commission's current policy, as discussed by Messrs Tracy, Behrns, and Mertens in their respective Statements, is that it creates a disincentive to contain costs. Suppose that the applicant could prove that cost overruns above its estimates were not the result of imprudence. Would that entitle the applicant to earn the adder on the project's actual costs? As Mr. Tracy notes in his Statement, a utility might well be acting within the bounds of prudence but still not taking all measures available to contain project costs.[127] When faced with two plausibly reasonable options, it will be inclined to take the option that increases project costs. As Mr. Tracy explained the problem:

> I do not mean to suggest that there cannot be legitimate reasons why a project applicant's ultimate costs will exceed its estimates. During periods of rising commodity or labor costs, for example, ultimate project costs may well exceed estimates, even estimates that contain contingency factors. But human nature being what it is, a developer, without being imprudent, might well put forth less than its best efforts to contain project costs when management knows that shareholders will actually benefit if costs are *not* contained.[128]

Conducting an examination of whether a utility's reasons for exceeding project cost estimates were valid or not would simply enmesh the Commission in an irrelevant inquiry that itself may produce ambiguous answers. Conversely, as noted earlier, there is no disincentive

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[127] Tracy Statement at P 22. The Commission itself has suggested that a utility's conduct will be considered imprudent only if the challenged costs are "attributable to patently unreasonable management action":

> The traditional tool for cost control in pipeline construction has been regulatory oversight, with the attendant threat of disallowing any investment imprudently incurred during construction. Such a regulatory approach, however, is a blunt instrument that is effective only to counteract extreme cases of management's lack of foresight or diligence. Before any costs may be disallowed from the rate base they must be shown to have been imprudently incurred, which implies that only those costs attributable to patently unreasonable management action may be disallowed.

Incentive Rate of Return for the Alaska Natural Gas Transportation System, FERC Stats. & Regs, Proposed Regs, ¶31,996 at 31,861 (1978).

[128] *Id.*

created by limiting the applicant's return adder to the project's estimated costs since it will continue to earn a normal return on the actual, prudently incurred costs of the project.[129]

Q 32: Should new reporting requirements be in place to allow the Commission to audit compliance with a requirement to limit incentives to some project cost estimate?

Joint Commenters have discussed above the proposal that incentive adders apply solely to the applicant's estimate of project costs at the time it applies for incentive rate treatment. That estimate, as Mr. Mertens states, will routinely include a substantial contingency factor.[130] The benefit of this approach is that it does not require the Commission to revisit the accuracy of the original estimate; that estimate establishes the upper bound on the value of the incentive, equivalent to a fixed payment.[131] This approach would not obviate the need for reporting requirements to audit compliance, but it would simplify the process. The utility would simply be required to demonstrate in a compliance filing after project completion that its rates reflect application of the adder to the estimate of project costs contained in its incentive rate filing.

Q 33: The Commission has general ratemaking policies with respect to CWIP and recovery of abandoned plant costs, as discussed below. Pursuant to Order No. 679, incentives above and beyond those general ratemaking policies may be requested on a case-by-case basis. Would it be appropriate to remove these issues from the case-by-case analysis of incentive requests, in favor of exploring changes to the Commission's general ratemaking policies? What would be the impact on ratepayers of revising these ratemaking policies, rather than authorizing higher levels of CWIP or recovery of costs of abandoned plant on a case-by-case basis?

The Joint Commenters do not oppose allowing the recovery of CWIP and abandoned plant costs in cases where the specific risks of the transmission project under consideration merit such rate incentives. They propose in response to Question No. 34 below a framework for the

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[129] Behrns Statement at P 10; Mertens Statement at P 10; Tracy Statement at P 24.

[130] Mertens Statement at P 9.

[131] *Id.* at P 12 ("since the utility would be allowed a normal return on its entire investment, limiting the adder to the project's estimated cost is just a way of quantifying how much of an incentive the Commission will allow and ensuring that the costs of the adder do not outweigh its expected benefits").

Commission's consideration of requests for transmission rate incentives, including recovery of CWIP and abandoned plant costs. They do, however, oppose making recovery of CWIP or abandoned plant incentives routine components of normal ratemaking. Not all transmission facilities projects merit such rate treatment, and not all of them should be given it. Such policies could lead to the undertaking of projects without a sufficiently rigorous assessment of the costs and benefits of those projects, simply because consumers would be effectively insuring the developers in all instances. This, in turn, could produce unjust and unreasonable transmission rates.

If, however, the Commission nonetheless chooses to make recovery of CWIP and abandoned plant costs a routine feature of transmission ratemaking, it should impose a rebuttable presumption that these incentives eliminate the need for any ROE incentive adder or other return-enhancing rate incentives. Otherwise, the Commission's transmission rate incentive policies will continue to be too one-sided, favoring developers at the expense of consumers.

Q 34: The Commission stated in Order No. 679 that it had not established specific eligibility criteria or conditions for incentives because it would limit the Commission's flexibility with respect to its application of the Rule. The Commission is interested in receiving comments regarding whether the establishment of criteria for eligibility for particular incentives would enhance regulatory certainty and predictability and serve to further encourage appropriate investment in transmission infrastructure. Should the Commission establish specific criteria or conditions that applicants must meet in order to be eligible for these individual incentives?

The Joint Commenters generally believe that *in cases where incentives are appropriate*, risk reducing incentives such as CWIP and abandoned plant incentives are the incentives that should be considered first, and that they are generally the only appropriate incentives for projects of intermediate risk, as described below.

The Joint Commenters propose a framework for a more rigorous application of the "nexus" test, based on the concept of a graduated approach to incentives calibrated according to the identifiable risks associated with specific transmission projects. The criteria suggested in this proposed approach for establishing incentives seek to emulate, in concept, the principles applied by doctors in prescribing antibiotics. Doctors might not (in fact, should not) prescribe antibiotics at all for routine infections, especially viruses. If they do prescribe, they select a type and dosage that will address the infection with the least possible interference with the patient's normal metabolism. For more serious infections, doctors will increase the strength of the antibiotic or choose one that is less often prescribed. Doctors reserve certain highly potent antibiotics for the most severe infections that cannot be resolved by more standard prescriptions. By systematically applying such a graduated approach, the Commission can achieve the objective articulated in Order No. 679 of "tailoring" incentives to project risks.[132]

a. Low Risk — There Should Be a Rebuttable Presumption That Incentives Will Not Be Available for Projects That Are Routine or Have Alternative Sources of Funds.

In common parlance, the term "incentive" implies a stimulus or provocation for a desired activity.[133] Conceptually, incentives are neither necessary nor appropriate to encourage transmission projects that are or should be undertaken in the ordinary course of a transmission provider's business or that are not distinguishable from projects commonly pursued by other developers. Consistent with this principle, the Commission should apply a rebuttable presumption that incentives will not be available to projects that the transmission provider is obligated to build by contract or tariff, that are necessary to comply with North American Electric Reliability Corporation ("NERC") Reliability Standards, or are otherwise not substantially different from other projects routinely considered through a regional planning

[132] *See* Order No. 678 at P 26.

[133] This understanding of the term is consistent with the Commission's observation at P 26 of Order No. 679 that it does not view incentives as simply "a 'bonus' for good behavior."

process. For similar reasons, many of the Joint Commenters believe there should be a rebuttable presumption that incentives will not be available for projects where the project developer has elected to forego alternative sources of funding, *e.g.*, project participation funds from other Load Serving Entities in the region that would be expected to pay the costs of the project in their rates or project participation funds provided by other experienced project developers interested in joint participation.

The Commission has stated on multiple occasions that incentives may not be appropriate for "routine" projects.[134] But in practice, it often has been difficult to identify characteristics that define a "routine" project. Logic supports a connection between the concept of a routine project and a course-of-business purpose for pursuing a project. If a transmission project is necessary to satisfy a contract or tariff obligation, that obligation ordinarily should be sufficient to support development of the project. Similarly, compliance with NERC Reliability Standards is part of a transmission provider's core business purpose. The Reliability Standards themselves (and the potential penalties for non-compliance) generally should be sufficient to support development of projects needed for Reliability Standards compliance. There should be a presumption (potentially rebuttable through a demonstration of unusual circumstances) that additional incentives will not be available for projects that are grounded in such core business activities.

The definition of "routine" also should include a comparative dimension. A proposed project would not be routine if it has specific characteristics (*e.g.*, technology, configuration, siting challenges) that establish a significant distinction from other projects approved through the relevant regional transmission planning process. Conversely, a project that is not materially distinct from other projects planned for the relevant region should be considered routine and,

[134] *See*, *e.g.*, Order No. 679 at P 94; *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084 at PP 48-55 (2007), *order denying reh'g*, 123 FERC ¶ 61,262 (2008).

therefore, not eligible for incentives. The Commission should not entertain applications for incentives based upon the bundling together of multiple projects that, individually, are routine. Likewise, the magnitude of investment in a particular project, by itself, does not necessarily demonstrate that a project is risky. The Commission clearly should not accept any suggestion that all transmission projects are non-routine. Such a premise would be fundamentally inconsistent with the concept of incentives and simply would inflate returns on all transmission projects (either directly or by shifting ordinary business risk). That result also would violate the FPA by authorizing returns in excess of levels associated with investments of comparable risk.

For similar reasons, the Commission should apply a rebuttable presumption that incentives will not be available where a transmission developer has made a voluntary decision to forego funding from other sources. It is logical to presume that a transmission developer that has rejected reasonable offers of joint project financial participation by other entities does not require incentives to invest in the project. Likewise, there is no apparent need for incentives where a transmission provider voluntarily agrees to fund network upgrades that interconnection customers otherwise would be required to fund under applicable Large Generator Interconnection Procedures. By taking advantage of alternative sources of funding, a transmission developer can substantially reduce the risks associated with project development.[135] While the point of incentives is to encourage acceptance of prudent risks, incentives should not have the perverse result of discouraging transmission developers from mitigating risks and reducing project costs where possible.

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[135] Tracy Statement at P 26.

b. Intermediate Risk - If the Project Has Significant and Demonstrable Risk Elements, Some Risk-Reducing Incentives May be Appropriate.

The Commission should consider risk-reducing incentives, such as CWIP, recovery of abandoned plant, and recovery of pre-commercial development costs, for projects that have significant and demonstrable elements of risk. Risk elements that appropriately could justify consideration of risk-reducing incentives include exceptionally difficult siting challenges, use of an innovative technology with limited performance data, and disproportionate and non-avoidable financial burden. Mitigating risks of these types may benefit consumers by supporting development of projects that are needed but that transmission project developers, without such mitigation of risks, might seek to avoid or defer.

Most transmission projects, by their very nature, raise siting and permitting challenges, and the Commission should not accept generalized claims of environmental or right-of-way issues as justification for incentives. However, where the transmission developer provides evidence of specific and unusually difficult siting issues, the Commission should consider incentives (such as recovery of prudently incurred abandoned plant costs) designed to mitigate the risks.

Likewise, if a proposed project will utilize a promising new technology with limited performance experience, risk-reducing incentives may be appropriate. The Commission, however, should apply appropriate “book-ends” where a transmission developer seeks to justify incentives based upon use of innovative technology. Use of a relatively new technology that nevertheless has a well-documented performance record and is widely recognized generally should not be sufficient to receive incentives. At the other end of the spectrum, the Commission should not encourage transmission developers to invest multi-millions of dollars in untested experimental technology by shifting all the associated risk of that investment to customers. The

Commission should make explicit that the "prudently-incurred" standard applies to all abandoned plant costs for which transmission developers seek recovery, including any such costs associated with investment in innovative technologies.

It also would be appropriate for the Commission to consider risk-reducing incentives where an individual transmission project involves a configuration or scope that would impose an extraordinary and unavoidable financial burden. Where the transmission developer demonstrates such circumstances, permitting full recovery of CWIP may mitigate cash flow burdens. Full recovery of prudently-incurred abandoned plant costs also may be appropriate where the transmission developer demonstrates that the risk of loss associated with recovery of half of abandoned plant costs (as permitted under the Commission's standard policy) would be so great as to threaten the transmission developer's financial stability or increase its overall costs for capital.

c. Highest Risk – Joint Commenters as a General Rule Favor Risk Reducing Over Return-Enhancing Incentives.

Even where a transmission developer demonstrates that a project involves exceptionally high risks, the Commission should seek first to address such risks through risk-reducing incentives. To return to the antibiotics analogy, the Commission should reserve consideration of return-enhancing incentives (*e.g.*, ROE adders) only for those specific circumstances where risk-reducing incentives cannot adequately mitigate specific and demonstrable risks associated with a project that is reasonably expected to produce significant benefits for customers.

The Commission should consider risk-reducing incentives prior to considering return-enhancing incentives, as risk-reducing incentives are more likely to promote necessary infrastructure development at a reasonable cost than return-enhancing incentives. Although financial analysts and risk managers regularly attempt to monetize risk, the outcome of that exercise is inherently imperfect. Further, risks are likely to change over time, and a return-enhancing incentive that may be reasonable at one stage of a project's development may overcompensate for risks or under-compensate for risks if the risks are assessed at a different stage. By contrast, the benefits of risk-reducing incentives are both more certain and more durable and, therefore, more likely to achieve the intended results.

In light of the anticipated effectiveness of risk-reducing incentives, the Commission should consider application of return-enhancing incentives only in very limited circumstances. The risk must be assessed on a project-by-project basis. Likewise, the efficacy of different types of incentives may vary among project developers. Joint Commenters expect that risk-reducing incentives will be sufficient to encourage development even of very high risk projects by most developers.

The unusual characteristics either of a specific project or a project developer might justify consideration of return-enhancing incentives in certain specific cases. If this does occur, however, there can be no justification for awarding both risk-reducing incentives *and* return-enhancing incentives for the same project. Risk-reducing incentives mitigate or eliminate project risks to developers and shift those risks to transmission customers. Where risk-reducing incentives apply, there is no rational basis for also granting the project developer any incentive that increases expected return above a level that would result from application of the Commission's generally applicable and well-developed rate of return policy. Transmission project developers seeking return enhancing incentives must, therefore, shoulder the associated risks of their projects, rather than seeking the best of both worlds – shifting of risks to transmission customers and enhanced returns based on those shifted risks.

As a necessary first step, the Commission must understand the risks that a proposed project actually faces. Traditional risks faced by almost any transmission project include the relatively minor risk of non-recovery of some portion of the costs of a completed project (prudence review), and the risk inherent in the permitting and siting processes that vary across the country and may lead to project cancellation after significant sums have been expended pursuing it. In addition, some companies can face cash-flow constraints during the period of time when investments must be made but before recovery is allowed. On the other hand, projects of unusual scope, *e.g.*, those involving innovative technology to solve complex reliability or congestion problems, may present additional risks beyond those faced by more conventional projects. The Commission must carefully identify the types of risk present in each case.[136] There can be no substitute for an analysis of what risks a specific project actually faces before consideration of incentives begins. The next step is evaluation of risk-reducing incentives that could help reduce those risks.

1. Full Recovery of Construction Work in Progress.

Full recovery of 100 percent of prudently-incurred CWIP for certain transmission projects squarely addresses the cash flow risk that applicants state may arise: (1) when expenditures are made during lengthy or complex siting or regulatory approval processes; or (2) because of financial constraints within the utility if expenditures for the project represent a significant portion of the company's working capital. Allowing ongoing recovery of one hundred percent of CWIP in lieu of an allowance for funds used during construction ("AFUDC") can give transmission providers access to improved cash flow during the period the line is

[136] Ironically, a project approved in a transparent and inclusive regional planning process, and thus qualified for the rebuttable presumption regarding rate incentives, likely faces less risk of a successful prudence challenge than projects that have not been developed through such a process.

undergoing permitting and construction. In certain cases, applicants have provided evidence demonstrating cost-savings to consumers associated with paying expenses currently rather than requiring the utility to carry those amounts. The mechanism can also mitigate the abrupt rate increase that can accompany a large project going into service. Commissioner Norris' partial dissent to two 2010 transmission rate incentive orders[137] makes this point. Recovery of CWIP can produce benefits to ratepayers, especially where the company can demonstrate real savings. Accordingly, use of this mechanism can sufficiently address the challenges faced by projects such as the "Intermediate Risk" projects described above.

2. Abandoned Plant Protections.

Recovery of one hundred percent of prudent abandoned transmission plant facilities costs, when abandonment of a project is not the choice or fault of the transmission developer, addresses the risk that opposition in the permitting process may result in the denial of necessary permits, or issuance of an approval so weighted with conditions that the project becomes infeasible. Abandoned plant protection can operate as an incentive to encourage transmission developers to invest in needed facilities without fear that they will not recover amounts expended pursuing projects that never go into service. Recovery of abandoned plant costs for meritorious transmission projects that are found to be needed in inclusive, regional planning processes, such as those described in the discussion of "Intermediate Risk" projects, may well be appropriate. Such a process should provide necessary assurance that a project has been found to be the best overall solution for customers in a region to address a particular need. However, entities that choose to forego participation in a transparent, inclusive planning process should assume the risk

[137] *PJM Interconnection, LLC*, 133 FERC ¶ 61,273 (2010); *Oklahoma Gas & Elec. Co.*, 133 FERC ¶ 61,274 (2010).

that a project will later be deemed unnecessary by a permitting authority, and ratepayers should not be required to fund such a developer's decision to follow a more speculative approach.

Recovery of abandoned plant costs does raise the question of how the Commission will determine whether a specific abandonment is or is not within the control of the project proponent, especially when the project is cancelled due to unacceptable permit conditions. Where a project, and its subsequent abandonment, is approved through such an inclusive, transparent planning process, the Commission could consider this as one factor in its evaluation of a utility's claim for recovery of abandoned plant costs. Similarly, abandonment due to project cancellation by unaffiliated generators for which the project is intended could also qualify as a factor for consideration. However, cancellation of a generation project affiliated in some way with the transmission developer, which leads to cancellation of a transmission project, should not satisfy the standard for recovery, as such a cancellation is within the control of the developer.

3. Commonly Used Incentives Should Not Become Routine Ratemaking Tools.

Just as a doctor should not prescribe antibiotics without seeing the patient and verifying that the ailment is one that an antibiotic can resolve, the Commission should not routinely permit incentives that depart from traditional ratemaking principles without verifying that the incentives are both necessary for the project and appropriate for the level of risk the project faces. The traditional exclusion of fifty percent of both CWIP and abandoned plant from rate base was derived from the principle that only investments that are "used and useful" to consumers should be included in utility rates[138] and longstanding precedent.[139] While the Commission has found reasons to deviate from this principle in particular cases, it is difficult to make broad

[138] James C. Bonbright, Albert L. Danielson & David R. Kamerschen, *Principles of Public Utility Rates, Public Utility Reports,* Virginia, at 246-47 (1988).

[139] *Hope,* 320 U.S. at 603; *Bluefield*, 262 U.S. at 679, 692-93 (1923).

generalizations about whether any particular category of incentive is generically beneficial to ratepayers. While allowing CWIP in rate base in lieu of granting AFUDC *can* reduce costs to consumers in some cases,[140] this is not true in every instance. Factors that can affect whether or not CWIP will be beneficial or detrimental to ratepayers for any specific project include the size of a company's construction program, the cost of money, growth rates and inflation. These factors can be company specific and difficult to tease out.[141] Only case-by-case review can determine whether CWIP would benefit ratepayers in a given case, or whether a particular project provides benefits that justify the additional ratepayer burden.

Similarly, abandoned projects that are never put into service do not meet the "used and useful" standard. While there may be reasons to encourage transmission providers to build such projects, the fact remains that as with CWIP, the abandoned plant incentive represents a shift of the projects' risk from the company shareholders, who traditionally undertook such risk for the right to earn a return thereon, to the ratepayers. Making the incentive available as a matter of course could encourage companies to propose less viable or less necessary projects that they would never consider if shareholders were to bear the costs of eventual abandonment. Case-by-case review of requests for project abandonment incentives assures ratepayers of at least some level of scrutiny by the company and the Commission that a given project is truly worth the additional ratepayer burden.

Neither CWIP nor abandoned plant recovery reduces the risks of siting or regulatory delays, cash flow shortages, or abandonment of the project for reasons outside the owner's control. Instead, they reduce the associated risk to the transmission owner by shifting it to

[140] *PJM Interconnection, LLC*, 133 FERC ¶ 61,273 (2010), partial dissent of Commissioner Norris.

[141] Joel Berk, *Public Utility Finance and Accounting: A Reader*, Financial Accounting Institute, New Jersey, at 113-118 (1989).

transmission ratepayers. The Joint Commenters recognize that sometimes this shift is appropriate. Indeed, as discussed above, the Joint Commenters believe that when incentives are appropriate, risk-reducing incentives should be the first (and often the only) incentives considered. Nevertheless, such a shift should continue to be considered on a case-by-case basis. Consumers deserve the protection of Commission scrutiny whenever a transmission owner seeks to transfer risks traditionally carried by investors to ratepayers.[142]

Q 35: What risks and challenges are appropriately addressed by the incentive ROE adder? Is it appropriate for the Commission to evaluate these risks and challenges on a project-by-project basis or on an aggregate basis for the applicant?

As noted in response to Question No. 34, there are few circumstances where risks and challenges would need to be addressed by an incentive ROE adder. The biggest risks for transmission projects, as Mr. Tracy notes, are the risks associated with siting or permitting delays, cash flow shortages, or the danger of abandonment of a project due to the actions of a regulatory body or separate entity. But even where the level of these risks is unusually high, these types of risk are squarely addressed by granting risk reducing incentives, such as CWIP and abandoned plant cost recovery. As such, there should be a rebuttable presumption against awarding both risk-reducing and risk-rewarding incentives for the same project.

Similarly, the Commission should establish a rebuttable presumption against ROE adders for any project an applicant is under a legal obligation to build. While the risks addressed by

[142] The Commission states for the first time in Order No. 1000 that where an incumbent transmission provider is (1) called upon to complete a transmission project that another entity has abandoned; or (2) has an obligation to build a project that is selected in the regional transmission plan for purposes of cost allocation but has not been sponsored by another transmission developer, such "situations would be a basis for the incumbent transmission provider to be granted abandoned plant recovery for that transmission facility, upon the filing of a petition for declaratory order requesting such rate treatment or a request under section 205 of the FPA." Order No. 1000 at P 267. That determination is the subject of pending rehearing requests but, assuming the Commission adheres to its position on rehearing, requests by incumbent transmission providers for abandoned plant cost recovery in such situations as a rate incentive should nonetheless be required to meet the incentive eligibility requirements Joint Commenters have advocated herein.

CWIP and abandoned plant are risks that are inherent in almost any transmission project, regardless of the obligation to build, incentive ROE adders provide no benefit to consumers for projects the owner is required to build, whether for reliability, contractual, or statutory reasons. Incentives are intended to encourage construction of projects that might otherwise not be built, not to increase profits on projects needed to meet legal requirements.

Because incentives should be tailored to the risks of specific projects, case-by-case review of such requests should remain the norm. The specific nexus between the project and the incentives is critical. The Joint Commenters' answer to Question No. 34 sets out their proposed framework for calibrating incentives to the level of a project's risk.

Q 36: Are there other considerations that the Commission should focus on when awarding an incentive ROE adder?

The Joint Commenters believe the answer to this question is yes. The Commission should consider the impact of incentive ROEs on the development of utility distribution facilities, which often carry lower base ROEs than those approved through Commission processes. Reduced state-approved ROEs reflecting current economic conditions create situations where utilities have the incentive to build transmission facilities at the expense of distribution facilities, increasing overall costs to ratepayers.

In Order No. 679, the Commission stated: "[w]e expect that an incentive ROE will make transmission projects more attractive, and therefore more likely, when transmission projects must compete for capital in vertically integrated utilities as well as in transmission and delivery utilities."[143] If the theory behind granting transmission incentives is that they are required because transmission projects must compete with other investment opportunities, the Commission should consider the overall effect of potential incentives on the comparative

[143] Order No. 679 at P 91.

attractiveness of other investment opportunities, such as a utility's distribution investments. ROE awards by the Commission that are significantly more generous than relevant state ROE allowances could skew utility investment decisions as between transmission and distribution level infrastructure additions. Joint Commenters address the issue of the skewing effect of Commission-granted ROEs as compared to state-allowed ROEs in their response to Question No. 8 above.

Q 37: Does the base ROE adequately compensate investors for the financial risk of the company, including risks associated with the particular transmission project for which incentives are sought?

Joint Commenters believe the answer to this question is yes. As noted in Order No. 679, the Commission's long-established Discounted Cash Flow ("DCF") methodology for developing allowed ROE already incorporates capital market perceptions of the risk associated with the operations of the project proponent.[144] The components of the DCF analysis directly reflect the perceived risks associated with the enterprise that is providing the capital. Moreover, the Commission consistently has insisted that cost of capital must be evaluated on an enterprise, rather than unbundled or functional, basis and specifically has rejected attempts to demonstrate that provision of transmission service generally is less risky than other aspects of an integrated company's business.[145] It is, therefore, already a notable exception to the Commission's policy of establishing allowed ROE on an enterprise basis to consider allowing enhanced returns for specific transmission projects. The bar to qualify for project-specific return enhancements should therefore be set correspondingly high.

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[144] Order 679 at P 27.

[145] *Otter Tail Power Co.*, 12 FERC ¶ 61,169, at p. 61,414 (1980); *Minnesota Power & Light Co.*, 12 FERC ¶ 61,264, at pp. 61,626-27 (1980), *aff'd sub nom. Cities of Aitken v. FERC*, 704 F.2d 1254 (D.C. Cir. (1982)); *Connecticut Light and Power Co.*, 43 FERC ¶ 61,508, at pp. 62,265-66, *order on reh'g*, 45 FERC ¶ 61,370, at pp. 62,164-68 (1988); *Boston Edison Co.*, 79 FERC ¶ 61,328 (1997); *Midwest Independent Transmission System Operator, Inc.*, 100 FERC ¶ 61,292 at PP 11-12 (2002).

Indeed, the base ROE likely over-compensates investors for many transmission projects. Transmission development, as a stand-alone business, is a relatively low risk business model, at least so long as the entity engages in inclusive planning and the costs of its projects are recovered through its transmission rates. Investors favor low-risk companies with stable, predictable returns. The parental capital structure for the International Transmission Company is roughly 32 percent equity and 68 percent long-term debt.[146] The markets thus assign much "thinner" capital structures to transmission-only companies to reflect their reduced risk. To the extent a company engages in riskier business ventures, such as generation development, the markets require a greater equity share to reflect the risks those businesses entail. There is no basis for imposing the increased risks of other business ventures on transmission customers.

Q 38: In determining the incentive ROE adder, and the requisite risks and challenges that support such an adder, should the Commission identify with specificity the types of risks and challenges that most warrant an incentive ROE adder?

Q 39: In determining the incentive ROE adder, should the Commission make a distinction between financial barriers to transmission development such as the ability to attract capital, and regulatory barriers, such as siting or environmental challenges? If so, how?

Q 40: In determining the incentive ROE adder, how should the Commission balance the impact of other risk-reducing incentives (such as CWIP and abandoned plant recovery)?

In response to Questions 38 – 40, Joint Commenters note that the Commission has employed a variety of risk-reduction tools to date. It is important to recognize that these tools have different purposes and different impacts on ratepayers. In addition, their cumulative impacts can be excessive even if the individual incentives are not by themselves unreasonable. The Commission has noted that the evaluation of whether an applicant has satisfied the nexus test will examine the total package of incentives being sought, the interrelationship between any

[146] *ITC Holdings Corp*., ValueLine Investment Survey, June 24, 2011.

incentives, and how any requested incentives address the risks and challenges faced by the project.[147]

Given that a company's ROE already reflects the level of risk that the market associates with the transmission provider, and given that incentives such as CWIP and abandoned plant protection go far to shift the risks inherent in transmission construction to ratepayers, situations where an ROE adder is necessary should be extremely rare. As noted above, the Joint Commenters advocate that project proponents receiving risk-reducing incentives (for projects of "intermediate" risk) should not also receive return-enhancing incentives for the same project absent a showing of extraordinary circumstances.

The Joint Commenters have noted recent Commission decisions that appear to suggest, without stating a hard and fast rule, that award of CWIP, abandoned plant, and other risk-reducing incentives warrant a 25 to 50 basis point reduction to the ROE incentive adders below what the applicant requested.[148] However, absent a showing of extraordinary risks, awarding *any* return-enhancing incentives on top of risk-reducing incentives is simply too generous. Where ratepayers are already shouldering typical investor risks such as cash flow problems and the risk of abandonment, they should not be asked to pay higher returns as well. The Commission has not articulated a basis for concluding that the grant of risk-reducing incentives equates to only a 25 to 50 basis point incentive ROE reduction. There is no reason to believe that shareholders whose risks have already been substantially mitigated should receive enhanced returns for a project facing substantially reduced risk.

[147] Order No. 679-A at P 21.

[148] *Central Maine Power Co.*, 135 FERC ¶ 61,136 (2011); *Desert Southwest Power, LLC*, 135 FERC ¶ 61,143 (2011); *Atlantic Grid Operations A LLC, et al.*, 135 FERC ¶ 61,144 (2011).

Q 41: Does regulatory assurance of cost recovery, either at the state or regional levels, mitigate the risks and challenges facing a transmission project? If so, how should the Commission give consideration to this mitigation in evaluating a request for incentive ROE adder based on a project's risks and challenges?

Joint Commenters answer this question in the affirmative. Once a project has received permitting approval from the relevant state or regional siting authority, the risks associated with non-recovery (prudence review), delay, and abandonment should be largely mitigated, and these projects should not be eligible for ROE adders.

Q 42: Is it appropriate to promote voluntary formation of Transcos, as defined in Order No. 679, through an ROE adder? Would other incentives promote Transco formation more effectively?

Joint Commenters as an *ad hoc* group take no position on the benefits or problems associated with the voluntary formation of Transcos. They do believe, however, that the transmission rate incentives awarded to a particular project should reflect the risks and potential benefits of that transmission project. As noted above, they believe that the granting of ROE adders should be reserved for specific projects with extraordinary risks justifying the grant of such a rate incentive.

Q 43: Order No. 679 does not distinguish between Transcos that are independent of generation-owning market participants and Transcos that are affiliated with such market participants. Would such a distinction be appropriate in terms of eligibility for, or the amount of, a Transco adder?

See the Joint Commenters' response to Question No. 42 above.

Q 44: Further, Order No. 679 did not distinguish between Transcos that result from divestiture of a vertically-integrated utility's existing transmission system and Transcos that are created for the purpose of developing a particular new transmission facility. Would such a distinction be appropriate in terms of eligibility for, or the amount of, a Transco adder?

See the Joint Commenters' response to Question No. 42 above.

Q 45: Is it appropriate to offer a standard ROE adder for all utilities that join or remain members of an RTO/ISO?

Joint Commenters believe that it is not appropriate to offer a standard ROE adder for all utilities[149] that join or remain members of an ISO, RTO, or other Commission-approved Transmission Organization (hereinafter "RTO"). FPA Section 219(c) provides in pertinent part that "the Commission shall, to the extent within its jurisdiction, provide for incentives to each transmitting utility or electric utility that *joins* a Transmission Organization."[150] Finding no prohibition in this language against extending the incentive to existing RTO members, the Commission, in Order No. 679, concluded that it would "approve, when justified, requests for ROE-based incentives for public utilities that join *and/or continue to be a member of* an ISO, RTO, or other Commission-approved Transmission Organization."[151] Doing so, it reasoned, was consistent with the purpose of FPA Section 219 because these utilities' continued membership in RTOs benefitted consumers by ensuring reliability and reducing the cost of delivered power.[152]

Placing aside the question of whether Section 219(c) of the FPA requires awarding RTO participation adders to existing RTO members, [153] Joint Commenters are concerned that since issuance of Order No. 679, the award of a 50 basis point ROE adder has essentially become standard operating procedure for new *and* existing RTO members.

[149] By "utilities" Joint Commenters refer in this section to "public utilities" under the FPA; these may include traditional utilities as well as single asset transmission companies.

[150] 16 U.S.C. § 824s(c) (emphasis added).

[151] Order No. 679 at P 326 (emphasis added).

[152] Order No. 679-A at P 86.

[153] Some of the Joint Commenters believe that this interpretation conflicts with the language of Section 219(c) and/or longstanding Commission policy that incentives are to be forward-looking inducements, *i.e.*, they are not awards for things the utility has already done. The Commission rejected this and other arguments in Order No. 679-A. Order No. 679-A at PP 82-90. While those arguments are not rehashed here, the Commission may wish to reconsider the merits of those arguments as it revisits its Order No. 679 policies.

The Commission stated in Order No. 679-A that it would "not specify a particular method for establishing the appropriate ROE for entities that join and/or continue to be a member" of an RTO in that proceeding.[154] "[T]he mechanics of setting an incentive ROE," it said, "is an issue best addressed in a proceeding evaluating the Transmission Organization incentive for transmission owners that belong to the particular Transmission Organization."[155] Since the issuance of Order No. 679, however, the Commission has denied protests to such incentive requests on the generic basis that such protests are inconsistent with the policy of Order No. 679-A and that the 50 basis point incentive has been approved for similar utilities.[156]

By invoking its generic Order No. 679 policy supporting the concept of RTO participation adders as a reason to deny consumers' objections both to the availability of the adder and its size, the Commission has effectively disabled itself from considering whether some lower ROE adder level would be appropriate, particularly for those utilities that are existing members of an RTO.

Joint Commenters recognize that the Commission's current policy is that incentive-based ROEs are to be filed with the Commission for approval in a Section 205 filing before the rates reflecting such incentives can be charged so that a determination of the ROE's overall zone of

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[154] Order No. 679-A at P 88.

[155] *Id.*

[156] *See, e.g.*, *Pepco Holdings, Inc.*, 121 FERC ¶ 61,169 at P 16 (2007) (granting a 50 basis point adder to the Pepco Holdings, Inc. affiliates for their continued membership in PJM, and in so doing, finding that a protest to the request for this adder is "inconsistent with Order No. 679-A" and noting that the Commission has approved the same adder for similar utilities); *Va. Elec. & Power Co.*, 123 FERC ¶ 61,098 at P 54 (2008) (denying requests for relief filed by protestors of the utility's request for 50 basis points increase in ROE on the basis that such an argument is "a collateral attack on Order No. 679-A" and noting that this incentive has been approved for similar utilities); *American Electric Power Service Corp.*, 121 FERC ¶ 61,245 at P 10 (denying rehearing and affirming summary approval of 50 basis point adder for utility's continued RTO membership and explaining that in Order No. 679, the Commission "called for case-by-case evaluation of whether a proposed incentive is justified" as opposed to generic application of the incentive in order to ensure that a "utility's rates remain within the zone of reasonableness").

reasonableness can be determined.[157] However, given that a summary grant of a 50 basis point adder generally has the effect of driving up the overall ROE to the upper end of the zone, a standard RTO participation adder of 50 basis points both for new and existing RTO members, without consideration of factors such as the amount of an adder that is needed to incentivize continued membership, is not likely to benefit consumers consistent with the goals of FPA Section 219.

Q 46: In the alternative, are there other incentives that the Commission should consider to encourage joining or remaining in an RTO/ISO?

Joint Commenters urge the Commission to revisit its current policy of incentivizing RTO membership. Specifically, the Commission should consider either eliminating the RTO incentive for existing members of RTOs or phasing out the incentive after a certain number of years of a utility's membership. Any grant of an ROE adder for RTO participation, including as proposed herein, should continue to be subject to the zone of reasonable returns determined in the context of a FPA Section 205 filing. Also, just as with the Commission's current policy,[158] any public utility that joins an RTO, but withdraws from such organization, should no longer be eligible for the incentive.

"The stated purpose of Section 219," the Commission stated in Order No. 679-A, "is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power."[159] Since the issuance of Order No. 679, however, the Commission has implemented a number of measures to ensure reliability and reduce the cost of

[157] *Northeast Transmission Development, LLC.*, 135 FERC ¶ 61,244 at P 74 (2011) (*citing* Order No. 679 at PP 77-79.).

[158] Order No. 679-A at P 79.

[159] *Id.* at 86.

congestion, including Order No. 890,[160] and most recently, its issuance of Order No. 1000 in Docket No. RM10-23. Both of these Orders were intended by the Commission to enhance regional planning processes for purposes of addressing both reliability and cost considerations.[161] These measures, coupled with the mature, longstanding relationship that many utilities have with their RTOs, have reduced whatever incentive, if any, that might be needed to encourage a utility's continued participation in an RTO. Indeed, since the broad transmission planning objectives of the Commission's proposed rule are to encourage transmission developers both inside and outside RTOs to participate in regional planning processes, the continued availability of RTO participation adders long after public utilities have joined an RTO results in an unjustified windfall at the expense of transmission customers.

Eliminating the incentive adder for longstanding members of an RTO is not only a permissible reading of the provisions of Section 219 governing incentives for *joining* an RTO, but is consistent with previous precedent under the FPA against awarding incentives for actions a

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

[161] *See, e.g.*, Order No. 890 at P 528; Order No. 1000 at PP 1-2. As the Commission noted in Order No. 890, the need to reduce the cost of congestion was a key factor in its determination to require RTOs to implement open and transparent transmission planning processes:

> [W]e do not believe that the existing pro forma OATT is sufficient in an era of increasing transmission congestion and the need for significant new transmission investment. We cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner. Although many transmission providers have an incentive to expand the grid to meet their state-imposed obligations to serve, they can have a disincentive to remedy transmission congestion when doing so reduces the value of their generation or otherwise stimulates new entry or greater competition in their area.

Order No. 890 at P 422. In Order No. 1000, the Commission stated that the Final Rule would support the development of transmission facilities identified by each transmission planning region as necessary, among other things, to satisfy reliability standards and reduce congestion. Order No. 1000 at P 2.

utility is supposed to do or has already taken,[162] including pre-Order No. 679 cases addressing the grant of an RTO participation adder for existing RTO members.[163] It is within the Commission's discretion to determine, consistent with its statutory mandate to ensure that its incentive rates are just and reasonable, whether granting utilities continued receipt of revenues for membership in an RTO is necessary to incentivize membership, or to ensure reliability and a reduction in the cost of congestion.

As support for its determination that utilities that had already joined an RTO should qualify for the RTO membership incentive, the Commission in Order No. 679 cited a utility's "option to withdraw" from an RTO.[164] "[T]he basis for the incentive," it stated, "is a recognition of the benefits that flow from membership [in RTOs] and the fact that continuing membership is generally *voluntary*."[165] But generic application of a 50 basis point adder conflates differences between the incentives appropriate to induce participation in an RTO and the lesser incentives appropriate to encourage continued participation. Just as a transmission owner's contractual obligation to construct facilities is a factor in determining its eligibility for a new transmission ROE adder,[166] so too is it relevant in determining a transmission owner's continued eligibility for

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[162] *See generally New England Power Pool,* 97 FERC ¶ 61,093 at 61, 477 (2001) ("This decision is in the public's interest as it does not unjustly reward NEP for doing what it is supposed to do. ").

[163] *See, e.g., S. Cal. Edison Co*., 114 FERC ¶ 61,018 at P 15 (2006) (rejecting a transmission owning utility's request for a 50 basis point incentive for "joining and remaining" a member of an ISO on the basis that the purpose of the adder was "to encourage transmission owners to turn over the operational control of their transmission facilities to a [RTO]; therefore, it does not apply to transmission owners who have already done so, as they need no inducement to take such an action."); *Allegheny Power Sys. Operating Cos.*, 111 FERC ¶ 61,308 at P 54 (2005) (finding that "PJM's current TOs became PJM members many years ago, so that the 50 basis point adder will not specifically serve as an incentive to those TOs to join an RTO. We therefore direct the parties to consider at hearing whether an adder is appropriate here."). While the Commission may have abandoned such reasoning in subsequent cases, that fact does not make it any less valid.

[164] Order No. 679-A at P 86.

[165] Order No. 679 at P 331 (emphasis added).

[166] Order No. 679-A at P 122.

a full 50 basis point RTO participation adder whether it has received certain benefits for joining, such as merger approval or market-based rate authority and whether those benefits are tied to ongoing RTO participation. Yet, the Commission has granted the RTO membership incentive even to utilities that have been members of the same RTO for a number of years and were either directed by merger condition or market-based authority condition to join RTOs.[167] Likewise, in instances where public utilities are obligated by statute, order, or contract to give advance notice of the intent to withdraw, the Commission has granted them 50 basis point incentives for RTO membership, even if they have not demonstrated any intention to withdraw from an RTO.[168] The generic approach currently implemented also disregards the disincentives and barriers that entities have, once they have joined an RTO, to extricate themselves from participation.

If the Commission is disinclined to eliminate the RTO membership incentive for existing members of an RTO, the Commission should consider phasing out the adder after a certain number of years. Specifically, the Commission should provide no more than a 50 basis point adder for RTO participation and phase out the adder after three years of membership of the entity or project in an RTO. For instance, if a 50 basis point adder is awarded when an entity first joins an RTO, the adder would be presumed to be eliminated after three years of the entity's

[167] *See, e.g., Am. Elec. Power Service Corp.*, 121 FERC ¶ 61,245 at PP 9-10 (2007) (denying a request for rehearing of the Commission's granting of a 50 basis point incentive for RTO membership for a utility that was bound to participate in Southwest Power Pool ("SPP") as a condition of a merger); *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 at PP 23, 28 (2004) (explaining that "it is essential that the [SPP] Membership Agreement provide that no jurisdictional transmission owner may exit SPP without a Commission determination that it is just and reasonable for it to do so").

[168] *See, e.g., Pac. Gas & Elec. Co.*, 120 FERC ¶ 61,296 at PP 14-15 (2007) (summarily granting the public utility's request for a full 50 basis point RTO membership incentive subject to suspension and the zone of reasonable returns determined at hearing despite the fact that PG&E provided no indication that it would abandon its RTO membership); Cal. Pub. Utils. Comm'n Decision 95-12-063, Dec. 20, 1995, Ordering Paragraph 1 (requiring all three California investor-owned utilities to transfer the operational control of the utilities' transmission facilities to the CAISO); CAISO FERC Electric Tariff No. 7, First Rev. Sheet No. 9, Second Replacement Transmission Control Agreement, Section 3.3 (effective Nov. 1, 2004) (CAISO Tariff section providing a mechanism under which a CAISO participant that intends to exit the CAISO must provide notice two years in advance of its withdrawal from the CAISO).

membership in an RTO. For entities that have already joined an RTO, and are currently receiving the adder pursuant to Order No. 679, the Commission's issuance announcing this revised policy should direct such recipients of the adder to submit a FPA Section 205 filing to implement the phase out or demonstrate why it should not be subject to a phase out. If the Commission is not inclined to issue such a directive, the Commission could also implement this "phase out" policy when an existing recipient of an RTO membership adder submits a new Section 205 rate filing in which it seeks continued application of the RTO participation incentive. For entities that do not make new Section 205 filings for continued approval of the RTO participation adder, the Commission should express its willingness to entertain Section 206 complaints to eliminate or phase out the RTO participation adders of RTO members who have already been allowed the full 50 basis point adder.

As discussed above, Joint Commenters believe that there is no need to continue incentivizing (via 50 basis point ROE adders) continued membership in an RTO in perpetuity. However, if the Commission does not find that elimination or phasing out of the adder for existing members of an RTO meets its policy objectives, the Commission should consider, in the alternative, limiting the size of the ROE incentive for RTO membership after public utilities have been RTO members for several years. Doing so would be consistent with the Commission's statutory obligation to ensure that its transmission rate incentive policies produce benefits to consumers. The Commission could implement this approach by revising its policy so that the size of the RTO incentive is gradually reduced for RTO members after an initial period. This "phase down" approach should be applied both to utilities seeking to join an RTO as well as those that are already participating in an RTO.

Under this “phase down” approach, the 50 basis point ROE incentive adder if granted, would remain in place only for a defined period of three years, subject to a determination on the zone of reasonable returns. Thereafter, the adder would be rebuttably presumed to decline to 25 basis points in years 4 to 6, and to 10 basis points for the utility’s remaining period of RTO participation. To overcome this phase down presumption, the utility would be required to show (and intervenors would have the opportunity to protest) that some unique factors warrant a deviation from the “phase down” of its RTO adder, such as evidence that the risks or financial constraints associated with its continued RTO participation are not adequately compensated with a reduced adder.

Similar to the approach for the phase out proposed above, the Commission’s issuance announcing this alternative revised policy should direct all current recipients of an RTO membership adder to submit an FPA section 205 filing to implement the requisite reduction based on the number of years of their participation in the RTO, or demonstrate why the entity should not be subject to the presumed level of an adder for its year of membership in the RTO. The Commission could alternatively implement this policy when an existing recipient of an RTO membership adder submits a new Section 205 rate filing in which it seeks continued application of the RTO participation incentive. If the Commission were to exercise the latter option for revising this policy, the Commission should express its willingness to entertain Section 206 complaints to reduce the RTO participation adders of RTO members who have already been allowed the full 50 basis point adder for a number of years and that have not made new Section 205 filings for continued approval of the RTO participation adder.

This proposal is wholly in accord with the provisions of FPA Section 219. The phase down approach is also consistent with Order No. 679. Among the bases for the Joint

Commenters' position in this regard is that the phase down approach addresses the Order No. 679 policy concern that RTO participation adders do not unduly discriminate by denying participation adders to existing RTO members.[169] Both existing and new RTO members would be eligible for RTO participation adders, but the proposed policy would recognize the qualitative difference between incentives needed to encourage utilities to join an RTO and incentives needed to encourage continued participation.

Nor would this proposal aggravate the Commission's concerns that denying RTO adders for existing members might create "perverse incentives for an entity to actually leave Transmission Organizations and then join another one."[170] Under this "phase down" approach, the Commission could determine, to reject a public utility's request for a new 50 basis point adder if it switches RTOs. Instead, the Commission could continue the utility along the same phase down schedule, providing it only with the level of the ROE incentive adder that it would have received had it not switched RTOs. The Commission should treat a utility that ends membership and then rejoins an RTO in similar fashion.[171] In sum, the current approach for incentivizing RTO membership should be revised so as to recognize the qualitative difference between encouraging utilities to join an RTO and encouraging utilities to continue their membership. The Commission should therefore eliminate, phase out, or reduce the level of the RTO participation incentive for existing RTO members as discussed above.

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[169] Order No. 679 at P 331.

[170] *Id.*

[171] For instance, assume that a utility were to terminate its RTO membership after three years (just before its ROE incentive adder is to be phased down to 25 basis points). Upon rejoining it would be entitled to no more than the RTO participation adder to which it would have been entitled had it remained a member of the RTO.

Q 47: Should the existing 50 basis point adder be increased to better encourage the formation and continuance of RTO/ISO arrangements?

No, the Commission should not increase the existing 50 basis point adder either to encourage new participation or to encourage continued participation in an RTO. As discussed above in response to Questions 45 and 46, it would be inappropriate to award standard higher ROE adders for RTO participation, particularly as it relates to entities that are already participants in an RTO.

The Joint Commenters also question the premise that a higher ROE adder would necessarily result in increased RTO participation. As evidenced by the fact that numerous entities joined an RTO prior to the issuance of Order No. 679, it is not the size of the "existing 50 basis point adder," but other factors that drive an entity's participation in an RTO, such as regulatory or legal requirements, merger conditions, or other non-voluntary factors. In the instance of an entity that is required to join an RTO, *e.g.*, pursuant to merger condition, law, or regulatory order, granting a higher profit to the utility than the current "standard" 50 basis point adder would serve to unnecessarily increase costs to consumers without a commensurate benefit.

In addition, some entities may determine not to join an RTO (if one even exists in the particular region) for various reasons unrelated to the size of the ROE adder. For instance, if a utility determines that it would be more cost-effective for its consumers if the utility would not become or remain part of an RTO, granting an ROE adder that is higher than the current standard 50 basis points may not affect the utility's decision to participate in an RTO.

A standard policy of granting higher ROE adders for RTO participation would also be inappropriate where an entity's participation in an RTO is voluntary. Consider as an example a merchant developer that competes to build a new transmission line that has been approved through a Commission-approved regional transmission planning process. If that merchant developer is the sole developer of the project and does not plan on assuming responsibilities associated with operational control of its newly developed transmission line and is not building the line in response to functional need or use by entities associated with it that are funding the cost of the transmission line, there is no basis for assuming that it needs to be "better encouraged" to turn over operational control of the transmission line to the RTO. Joint Commenters believe it is neither justified nor appropriate to award higher RTO participation adders than the 50 basis points that is currently awarded to new RTO members. Increasing the RTO participation adder would likely yield unjust, unreasonable, and unduly discriminatory results.

Q 48: Is the existing 50 basis point adder appropriately scaled to encourage the formation and continuance of RTO/ISO arrangements?

Joint Commenters believe the answer to this question is no, for the reasons stated in their responses to Question Nos. 45 to 47.

Q 49: How does the current incentive allowing recovery of 100 percent of prudently incurred abandoned plant costs affect the sharing of risks between investors and customers? Are there reasonable conditions or safeguards that could be imposed to ensure risks are appropriately allocated? For example, should recovery of abandoned plant costs be exclusive of carrying charges? Should carrying charges exclude any ROE incentive?

Recovery of prudent abandoned transmission plant facilities costs when the abandonment of a project is not the choice or fault of the transmission developer addresses the risk that opposition in the permitting process may result in the denial of necessary permits, or an approval so weighted with conditions that the project becomes infeasible. The abandoned plant protection can operate as an incentive to encourage transmission developers to invest in needed facilities without fear that they will not recover amounts expended pursuing projects that never go into service. Recovery of abandoned plant costs for meritorious transmission projects that are found to be needed in inclusive, regional planning processes may well be appropriate. Such a process should provide necessary assurance that a project has been found to be the best overall solution for customers in a region to address a particular need. However, entities who choose to forego participation in a transparent, inclusive planning process should assume the risk that a project will later be deemed unnecessary by a permitting authority, and ratepayers should not be required to fund such a developer's decision to follow a more speculative approach.

Recovery of abandoned plant costs does raise the question of how the Commission will determine whether an abandonment is or is not within the control of the project proponent, especially when the project is cancelled due to unacceptable permit conditions. Where a project, and its subsequent abandonment, are approved through such an inclusive, transparent planning process, the Commission could consider this as one factor in its evaluation of a utility's claim for recovery of abandoned plant costs.

Recovery of costs for abandonment should not include carrying charges and should not include any ROE incentive. The developer whose transmission project does not proceed for reasons outside of the developer's control should be made relatively whole. However, a specific rate of return or profit margin should not be guaranteed. To truly provide the necessary incentive to build through to completion, the costs to make that developer whole should not include any ROE incentive adder. That incentive should only be received by those developers that complete transmission projects found to justify such an extraordinary grant of return-enhancing incentives, and which actually provide the benefits attributable to such projects.

Q 50: Should abandoned plant costs be prohibited in instances where an affiliated project eliminates the need for a transmission project?

Joint Commenters answer this question in the affirmative. If the development of an affiliated project or the cancellation of an affiliated project eliminates the need for the transmission project in question, then the abandoned plant costs for that transmission project should be borne by the developer or its shareholders. For instance, cancellation of a generation project affiliated in some way with the transmission developer, which leads to cancellation of an associated transmission project, should not satisfy the standard for recovery, as such a cancellation is within the control of the developer.

Q 51: Are there additional measures that can be taken to either limit the risk of abandonment, or mitigate the impact of allowing recovery of 100 percent of abandoned plant costs on customers?

Yes. Transmission project developers can limit the risk of abandonment by submitting their project to the open, transparent planning processes of the applicable regional transmission entity. These planning processes help to ensure that the resulting project is necessary and/or economically viable and is located to provide the optimum benefit to the system.

Project developers should also perform the necessary research of state and local laws to understand fully the permitting requirements that are applicable to their particular transmission project. To the extent possible, project developers should meet with state and local regulatory authorities, both in advance and during the process of submitting their project to the regional planning processes and seeking Commission-granted rate incentives. Better communication with interested stakeholders will provide greater understanding of the proposed project and its costs and benefits. Better communication and embracing an open transparent process will greatly help to overcome regulatory hurdles and potential litigation.

Project developers should also work to ensure that all costs, including regulatory costs and attorney fees, are incurred prudently and that the appropriate stakeholders are given the necessary information to be assured that the project is not being “gold-plated” or unreasonably expensive. Again, more emphasis upon original transmission planning through an open and transparent process would help to assure that all stakeholders agree that the project is viable and beneficial.

Q 52: Some interveners in various transmission incentives proceedings have raised concerns that the incentive of allowing 100 percent recovery of prudently-incurred abandoned plant costs could encourage applicants to pursue projects of greater risk. How should the Commission consider and address this factor?

It would appear to be obvious that someone who has nothing to lose would be willing to take greater risks. In reviewing requests for transmission rate incentives, the Commission should consider whether a transmission project is reasonably viable, *i.e.,* it fulfills a transmission-related need (as evidenced, for example, by inclusion in a regional transmission plan), and has a commercial/business case to support its construction. While an important objective of transmission rate incentives is to encourage the development of new technologies, a line should be drawn between new technologies that have a demonstrated scientific basis and technologies that are totally unproven with no scientific basis. Otherwise, consumers end up funding what is essentially research and development.

Q 53: Should the Commission allow recovery for partial abandonment of projects? If so, how should partial abandonment be defined? What criteria should the Commission consider when deciding whether a project has been partially abandoned? What would be the consequences of the Commission allowing recovery of abandoned plant cost for a portion of a project and later denying recovery of abandoned plant costs for the entire project (*e.g.*, finding that abandonment of the full project was under the control of the project developer)?

Recovery for partial abandonment of projects should only be allowed if the entire project was previously approved by a regional transmission entity as part of its open transparent transmission planning process. A developer should not be allowed to recover abandonment costs if the developer makes an overly grand transmission proposal that is cut down to size by a regional transmission planning process. Only if the portion of the project that has been approved through an open transparent planning process is later abandoned for reasons beyond the developer's control should the developer be able to recover the costs of that approved portion.

Q 54: If the recovery of abandoned plant costs were made contingent on the abandonment or cancellation of all or a substantial portion of a transmission project, how should the Commission define a "project" for the purpose of applying the abandoned plant incentive? The Commission has stated that several individual transmission projects may be characterized as a single project, or as several individual projects, depending on the showing made by the applicant. Should this characterization limit how an applicant may recover abandoned plant costs?

Recovery of abandoned plant costs should be made contingent on the entire project or grouping of projects being approved in a regional transmission planning process. However, if a developer proposes a large project or a grouping of projects and only a portion of that is approved through a regional transmission planning process and later the entire project or group is abandoned due to state or local permitting issues, only the abandoned plant costs for the portion of the project group that was previously approved in the planning process should be recoverable.

Q 55: If a project developer is granted the incentive for 100 percent recovery of abandoned plant costs, but is denied a request to recover abandoned plant costs under this incentive, then is it appropriate to recover those costs through other accounting treatments in a subsequent section 205 filing? If so, what accounting treatments would be appropriate?

Joint Commenters believe the answer to this question is no.

Q 56: If a utility receives recovery of abandoned plant costs incentives and subsequently abandons its project, what rate of return (including incentive ROE adders), if any, should be applied to the abandoned plant costs until the costs are ultimately recovered in rates?

As indicated above in Joint Commenters' response to Question No. 49, while a utility may be entitled to recover abandoned plant costs in order to be made whole, a profit (*i.e.*, rate of return, and especially incentive ROE adders) should not be guaranteed for failure to complete the project. Previously granted rate of return and incentive ROE adders should only be recoverable if the project is completed and put into service, as it is only at that time that consumers and the system benefits from the project.

Q 57: What are the appropriate bases for evaluating a request to recover 100 percent of CWIP? Does including 100 percent of CWIP in rate base more appropriately address project specific risks and challenges or the aggregate risks and challenges associated with all projects an applicant is undertaking in a certain time period? If the aggregate risks and challenges are more appropriately addressed by including 100 percent of CWIP in rate base, how should the risks be reconciled with a Commission policy to evaluate risks and challenges on a project specific basis?

Requests for recovery of 100 percent of prudently-incurred CWIP for certain transmission projects should squarely address the cash flow risk that applicants state may arise: (1) when expenditures are made during lengthy or complex siting or regulatory approval processes; or (2) because of financial constraints within the utility if expenditures for the project represent a significant portion of the applicant's working capital. The requests should also demonstrate whether, and to what degree, CWIP would serve to mitigate the potential abrupt rate increase that can accompany a large project going into service without CWIP.

As to whether including 100 percent of CWIP in rate base more appropriately addresses project specific risks and challenges or the aggregate risks and challenges associated with all projects an applicant is undertaking in a certain time period, the inquiry itself is case specific. Indeed, it is the Commission's existing position that CWIP requests must be made for each individual project even where the applicant claims an aggregate risk.[172] CWIP addresses cash flow risks. These are likely to be created by specific, large projects. But even the determination that there are aggregate cash flow risks and challenges associated with multiple projects undertaken in a certain time period still requires a project specific analysis to ascertain that this is the case. The analysis may reveal, for example, that the timing of multiple projects is creating a cash flow risk that would be unnecessary if the applicant adopted project staging plans.

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[172] *PJM Interconnection, LLC & Pub. Serv. Elec. & Gas Co.,* 135 FERC ¶ 61,229 at P 53 (2011).

Q 58: What is the impact on ratepayers of allowing 100 percent CWIP in rate base prior to commercial operation? What kind of information should an applicant submit to make a showing that granting 100 percent CWIP will benefit consumers?

The real impact on ratepayers ultimately depends on the size of the project. However, regardless of project size, allowing 100 percent CWIP in rate base prior to commercial operation increases rates during a time frame when the consumer receives no tangible benefit from the facilities. The applicant should therefore submit substantial proof that early payment will result in a net reduction of overall costs to consumers. Specifically, the applicant should show that CWIP will lower capital costs to consumers over the life of the project and that there are no significant intergenerational equity concerns (*i.e.*, that the consumers who pay CWIP may not be the same consumers who benefit when the plant goes into service).[173]

Q 59: In addition to the rate impact data required under 18 C.F.R. § 35.13(h)(31) and (32), what rate impact tests could be considered in evaluating a request for including 100 percent of CWIP in rate base?

See the Joint Commenters' response to Question No. 58 above.

Q 60: Should the CWIP incentive not apply or be suspended in circumstances where an incentives project has been suspended for an indefinite period of time and there is no additional construction activity on the project?

Yes. By definition, rate base treatment for construction work *in progress* contemplates ongoing construction. CWIP should be removed from the rate base if the project has been suspended indefinitely and there is no additional construction activity.

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[173] Historically, a major concern with granting CWIP was the potential for intergenerational inequity in the allocation of power supply costs. At a time when most wholesale power supplies were bundled with transmission service, the concern was that wholesale customers asked to bear the costs of construction work in progress might switch wholesale suppliers before the project was placed in service and never realize the benefits of their up-front payments for generating facility costs. *See Mid-Tex Electric Cooperative v. FERC*, 773 F.2d 327 (D. C. Cir. 1985). Intergenerational inequities are less of a concern where CWIP relates to the costs of *transmission* facilities under construction. This is because even customers able to switch wholesale suppliers are likely to remain dependent on their transmission providers for the transmission facilities used to deliver their power supplies, regardless of whether they switch power suppliers.

The foundational premise for granting the incentive under Order No. 679 in the first place is to improve reliability and/or relieve congestion; however, the applicant cannot meet these goals to which it has committed if construction is halted. Accordingly, the applicant should not be able to reap the benefits of CWIP and increase costs to the consumers in cases where the applicant has stopped construction because the consumer will receive absolutely no foreseeable benefit.

While applicants should not receive CWIP indefinitely, defining indefinite suspension is a separate issue. Joint Commenters see two scenarios that could trigger the conclusion that an indefinite suspension has occurred. The first is a "Declared Suspension" where the applicant/developer admits that construction no longer is underway and it is suspending development indefinitely. In such a case, removal of previously-approved CWIP should be automatic. The second is a "De-Facto Suspension" where construction has been delayed or halted, but the applicant/developer does not admit indefinite project suspension. For this De-Facto Suspension, customers and other parties affected by the halting of the project should have the opportunity to demand a formal project suspension or justification why the applicant/developer does not consider it has suspended the project indefinitely (*e.g.*, a temporary shortage of steel). Under either scenario, however, once the Commission determines a project has been suspended indefinitely, project capital costs previously granted rate base treatment as CWIP should be removed from the rate base for the period construction is not in progress. In the event construction resumes after an extended period of suspension, the applicant should have to re-justify the application of CWIP to the project. Circumstances and risks change. Hence, the premise for originally granting CWIP as an incentive may no longer apply under new conditions.

Q 61: In the past, the Commission implemented a phasing-in of rate treatments to limit their rate impact to consumers. Should the Commission consider such limits for certain incentives such as CWIP?

Joint Commenters agree that phasing in of CWIP could make great sense in certain situations. The phasing-in of CWIP is an excellent tool to limit the impact on consumers by preventing rate shock.[174] Implementing a CWIP phase-in acts as a cap on how much an applicant can actually reflect in CWIP.

If the Commission adopts a phased-in approach to CWIP, this should not change the justification needed for an applicant to obtain an increased CWP allowance, even though the impact on consumer is less than it would have been under a standard CWIP approach. Applicants should still be required to show that getting an increased CWIP allowance would provide benefits to consumers.

Q 62: If the applicant is granted an incentive ROE adder and 100 percent CWIP in rate base, should the incentive ROE adder be applied to 100 percent of CWIP included in rate base?

If the applicant receives CWIP, except in unusual circumstances, it should not be able also to receive an ROE adder, much less an adder applied to CWIP. As explained in response to Question Nos. 33 to 35 above, Joint Commenters believe that an applicant should not be able to receive a risk-reducing incentive such as 100 percent of CWIP as well as an increase in return with an ROE adder.

A fortiori, the Commission should not apply an ROE adder to CWIP. The ROE adder is intended to cushion the effect of an added risk, so there is no logic in granting an adder to CWIP. CWIP by its very nature reduces risk. For example, a primary reason for seeking and securing 100 percent CWIP is to obtain up-front regulatory certainty to satisfy an applicant's lenders.

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[174] If, for example, the Commission concluded that a CWIP-related rate increase of 20% would cause rate shock, phase in of CWIP would be an obvious way to ameliorate that impact.

Applying an ROE adder to 100 percent of the CWIP does not provide any more regulatory certainty than the applicant would already receive from CWIP without the ROE adder.

Q 63: Is there a reasonable debt to equity split, or a procedure for determining such, that should be applied generally to future applications, or that can be applied generally to classifications, such as a general split for publicly owned projects and a general split for investor owned projects? Or is this best suited for case by case determination? What kind of information should an applicant provide in order to support an application for a hypothetical capital structure?

Q: 64 Is there a reasonable point in time at which the actual capital structure should be required to match the hypothetical capital structure and that should be applicable generally to future applications?

The use of hypothetical capital structures for Commission-regulated public utilities may falsely magnify the risks of an inherently low-risk line of business. Hence, Joint Commenters in response to Questions 63 and 64 state that they generally do not support the use of hypothetical capital structures as a transmission rate incentive for public utilities.

Transmission development, as a stand-alone business, is a relatively low risk business, at least so long as the developing entity engages in inclusive regional planning processes and the costs of its projects are recovered through the transmission rate. Even when transmission projects are developed outside of a traditional transmission rate structure, the signing of transmission service contracts in advance with "anchor" customers is usually required for the project to be financed and move forward. Investors favor low-risk infrastructure companies with stable, predictable returns. As one example, the capital structure for the parent company of International Transmission Company is roughly 32 percent equity and 68 percent long-term debt.[175] The markets, thus, support much "thinner" capital structures for transmission-only companies, due to the low risk nature of their business. To the extent a company also engages in riskier business lines, such as generation development, the markets require a greater equity share

[175] *ITC Holdings Corp.*, ValueLine Investment Survey, June 24, 2011.

to reflect the risks those businesses entail. But there is no basis for imposing the increased risks of such other business ventures on transmission customers of public utilities.

Hence, any public utility seeking a hypothetical capital structure as a transmission rate incentive should be required to present compelling evidence of special circumstances requiring the use of a capital structure other than its actual structure in order for the project to go forward. Assuming, *arguendo*, that the Commission agrees to allow a hypothetical capital structure for a public utility in a particular case, use of a thicker hypothetical capital structure in such cases should eliminate any need for ROE adders.[176]

Publicly-owned and cooperative utilities participating in transmission projects can present special issues, as they often are funded at close to 100 percent by debt. Joint Commenters are taking no position in these comments on the use of hypothetical capital structures by publicly-owned or cooperative utilities.

Q 65: CWIP related costs should not be recorded as pre-commercial costs. What additional measures could be considered to prevent the inclusion of costs as pre-commercial that should appropriately be recorded as CWIP and recovered over the useful life of a project? In the case of deferred recovery, would limiting the period of time that carrying charges will be allowed help to ensure timely development of a project and guard against unreasonable delays?

Joint Commenters take no position on the issues raised by Question No. 65. They note, however, that in response to Question No. 30 above (regarding possible use of incentives to reward early and under-budget completion of projects), Joint Commenters have outlined the safeguards the Commission should consider if it intends to provide incentives to transmission developers to complete their projects on a timely basis.

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[176] *See Am. Transmission Co., LLC and Midwest Indep. Transmission Sys. Operator, Inc.*, 105 FERC ¶ 61,388 (2003).

Q 66: If incentives for both pre-commercial cost recovery on a deferred basis and 100 percent recovery of abandoned plant costs are granted, is there a relationship between the two incentives such that the Commission should review the types of costs that are included in the regulatory asset, the allowance of carrying charges, or the time period over which a regulatory asset is recovered in rates for pre-commercial cost recovery?

Yes, Joint Commenters believe that such a review would be appropriately undertaken in such circumstances.

Q 67: Does the current practice of allowing carrying charges on deferred recovery of pre-commercial costs at the overall cost of capital, including incentive ROE adders, appropriately balance the sharing of risks of transmission project development between utility applicants and customers and affect the overall level of pre-commercial costs? How should this practice be changed to better allocate the risks between applicants and customers and to ensure that pre-commercial costs are reasonable?

Joint Commenters believe this practice should be reviewed. In particular, they have concerns with allowing incentive ROE adders to be included in such carrying charges. Incentive ROE adders should only be allowed in the most extraordinary of circumstances.

Q 68: Should the Commission change the way it determines what constitutes an "advanced" technology that is appropriate for incentives?

Joint Commenters answer this question "yes." The Commission should focus on advanced technologies that serve the core purpose of increasing reliability of the bulk electric system and/or reducing the cost of delivered power by easing congestion, while at the same time accomplishing these goals in a cost-effective manner. Specifically, the Commission should require applicants to provide more than just an "intention" to use a particular advanced technology. Statements such as "the applicant is considering . . . ." should not be viewed as sufficient for the Commission to grant some form of incentive for the use of an advanced technology that may never actually be put in place.

Joint Commenters do not endeavor in these comments to provide a technical discussion as to what is or is not an advanced technology. Rather, it is their goal here to point out that many of the petitions for incentive rate treatment being submitted to the Commission that purport to contain the necessary attributes as to advanced technologies for use in a particular project are flawed. Petitioners often provide a summation of various advanced technologies that are being *considered, evaluated*, or *are subject to further analysis and possible use* in that particular project. Joint Commenters submit that the *potential use* of certain advanced technologies should not in any way be considered by the Commission as a sufficient showing that such advanced technologies will *actually* be deployed, and as such, form no reasonable basis for the grant of incentives.

In fairness, and as is usually the case, petitions for a declaratory order for incentive rate treatments are generally filed when the project in question is still very much on the drawing board. The final design and components of a particular transmission project may not be finalized until long after the declaratory order has been acted on. Therefore, Joint Commenters recommend that the Commission consider a different approach to possible incentive rate treatment for the use of advanced technologies.

In those cases where petitioners make a compelling case for incentives based on the use of advanced technologies, but have not provided any firm commitments to actually employ such technologies in their projects, the Commission could conditionally grant any needed incentives subject to a further evidentiary showing at the appropriate time. To be clear, and as discussed in the response to Question No. 72, the incentive ROE adder for the use of advanced technology should only apply to the cost of such technologies – and not to the entire project. The incentive, if granted, would be subject to disallowance in the case where the petitioner never actually incorporates the technology, or where the petitioner fails to provide the necessary evidentiary showing that the technologies were used. Joint Commenters submit that a structural change as recommended here is warranted, as the current system of analyzing *potential* technologies that may or may not actually be used, is unsound.

Q 69: Section 1223 of EPAct 2005 defines advanced transmission technology and lists technologies that fall within that definition. How should the Commission account for what Order No. 679 identified as the evolving nature of technology?

The Commission should seek to incentivize prudent investments in the the use of "cutting edge" technologies. The Commission should expect that any new infrastructure would reflect and incorporate current "best practices" in use by the transmission industry. Incentives should not be awarded simply because a project incorporates designs and features that are the current industry standard. Technologies that truly push the envelope are the types of evolving technology that the Commission should focus on. That said, Joint Commenters submit that such technologies, on a case-by-case basis, should be evaluated using a cost/benefit methodology. Petitioners should be required to provide a complete showing that the use of a particular technology will provide positive ratepayer benefits, or, alternatively, that as the technology develops and is more widely adopted it will provide positive ratepayer benefits.

Q 70: Does the above-noted standard – examining whether a proposal reflects a new or innovative domestic use of a technology that will improve reliability, reduce congestion, or improve efficiency – strike an appropriate balance?

True innovation that can be implemented in an efficient manner, to the benefit of both consumers and the utility, could strike a reasonable balance.

Q 71: Should an applicant's level of previous experience with a technology be a factor in determining whether that technology is "advanced" for purposes of evaluating a request for incentives? If an applicant has previous experience using a technology that otherwise has not been widely adopted, should that applicant's proposed use of the technology be considered "advanced"? If an applicant has no previous experience in using a technology that is otherwise widely adopted, should that applicant's proposed use of the technology be considered "advanced"?

If an applicant is truly a "first-mover" and is at the head of the pack as to the implementation of an efficient advanced technology, then subsequent use of that technology by the applicant could be considered by the Commission as advanced. Conversely, an applicant that is proposing to use a technology for the first time, although widely in use elsewhere in the industry, should not be rewarded for being "behind the curve."

Of course, reasonable time limitations must be considered as to how long a particular applicant can continue to claim "advanced" status when that technology has been well-developed and put in use by that applicant. The Commission could, however, consider such factors as to whether that particular applicant has continued to improve and upgrade the technology through continued use and real-world applications. Joint Commenters submit that these type of analyses are best left to a case-by-case resolution, and are likely not suitable for any type of "bright-line" test.

Q 72: Where the Commission grants an incentive ROE adder for the use of advanced technology, should that adder apply to the entire cost of a project, or just to the advanced technology?

Joint Commenters believe that the adder should only apply to the cost of the advanced technology. Consistent with the discussion in response to Question No. 68, this is an issue that should likely be carved out for separate treatment in any Commission order on this issue. If the requisite, definitive showing is made that some form of advanced technology is being incorporated into a project that would qualify for incentive rate treatment, then any ROE adder granted should only be associated with the costs of that technology.

WHEREFORE, Joint Commenters urge the Commission to undertake in this docket a full review of its transmission rate incentives policy, and after such review, to adopt a revised policy that limits the granting of incentives only to: (1) transmission projects that are found to be needed and that would not be constructed but for the granting of such incentives; and (2) a reasonable package of incentive measures that, taken together, reduce the risk of the project to acceptable levels for both project applicants and end use consumers, without resulting in unjust and unreasonable rates.

Respectfully submitted,

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September 12, 2011

ATTACHMENT A

SUMMARY OF FERC ORDERS ON INCENTIVE APPLICATIONS FOR TRANSMISSION DEVELOPMENT

AUGUST 25, 2011

FERC ORDERS ON INCENTIVE APPLICATIONS FOR TRANSMISSION DEVELOPMENT[1]

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Nevada Hydro (ER06-278-000)	2006	The Commission deferred ruling on the merits of certain rate principles requested by Nevada Hydro for a proposed combined generation/transmission project, pending submission of additional information that the Commission deemed necessary to complete its evaluation of Nevada Hydro's proposal.						
Bangor Hydro (ER04-157-004) Opinion No. 489	2006 (Reaffirmed on Rehearing in 2008)	50 basis points (transferring operational control to ISO New England) AND 100 basis points (encourage expansion) (Multiple Projects)	N/A	N/A	N/A	N/A	N/A	N/A
AEP (EL06-50-000) (conditional grant)	2006 (Denied Rehearing in 2007)	ROE set at "high end of zone of reasonableness"	N/A	X	X	N/A	N/A	N/A
Allegheny Energy (EL06-54000) (conditional grant)	2006 (Denied Rehearing in 2007)	ROE set at "high end of zone of reasonableness"	X	X	X	N/A	N/A	N/A

[1] As of August 25, 2011

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Duquesne (EL06-109-000, et al.) (conditional grant)	2007	150 basis points (of 150 requested)	X	X	X	N/A	N/A	N/A
The United Illuminating Company (ER07-653-000) (conditional grant)	2007 (Denied Rehearing in Jan. 2009)	50 basis points for underground portion of project only	N/A	X	N/A	N/A	N/A	N/A
Trans-Allegheny Interstate Line Company (ER07-562-000 and ER07-562-001)	2007 (Denied Rehearing in Oct 2007)	ROE set at "high end of zone of reasonableness," but suspended until June 1, 2007, as requested, subject to refund	N/A	N/A	N/A	N/A	N/A	N/A
Commonwealth Edison Company and Commonwealth Edison Company of Indiana (EL07-41-000, ER07-583-000 and ER07-583-001)	2007	Denied (request of 150 basis points)	N/A	Denied	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Baltimore Gas & Electric Company (ER07-576-000 and ER07-576-001)	2007 (Denied Rehearing in Jan 2008)	100 basis points (of 100 requested) for only two RTEP projects and 50 basis points for continued membership in PJM and Denied for 37 future projects	N/A	Denied	N/A	N/A	N/A	N/A
Southern California Edison Company (EL07-62-000)	2007 (Denied Rehearing in June 2008)	125 basis points (of 150) for the DPV2 and Tehachapi Projects and 75-basis points (of 100) for the Rancho Vista Project.	X	X	N/A	N/A	N/A	N/A
Baltimore Gas & Electric Company (ER07-576-000 and ER07-576-001)	2007 (Denied Rehearing in June 2008)	100 basis points (of 100) for TOI Projects	N/A	N/A	N/A	N/A	N/A	N/A
Pepco Holdings (ER08-10-000)	2007	50 basis points (of 50) (for continued membership in PJM)	N/A	N/A	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Xcel Energy Services (ER07-1415-000)	2007	N/A	X	X	N/A	N/A	N/A	N/A
Commonwealth Edison Company (EL07-41-001 and ER07-583-003) (Rehearing of 2007 order)	2008 (Granted rehearing again in Sept. 2008 and reaffirmed)	150 basis points (of 150) for Phase II of the West Loop Project in Chicago and Denied for Phase I and Grenshaw Project	N/A	X (Granted for Phase II only)	N/A	N/A	N/A	N/A
Atlantic Path 15 LLC (ER08-374 and EL08-38-000)	2008 (Granted rehearing in part in Nov. 2010)	The Commission established hearing and settlement procedures to review the proposed tariff change to decrease rates for transmission service and summarily approved Atlantic's proposed continued use of the 13.5 percent return on equity. On partial rehearing, FERC clarified that it is not mandating that companies use a regional proxy group for purposes of calculating return on equity (ROE) in rate filings in this or other cases. The Commission also clarified that whether it will make an up-front ROE determination will depend on the facts and circumstances of particular cases.						
Potomac-Appalachian Transmission Highline (ER08-386-000)	2008 (Rehearing Granted in part in Nov. 2010 - set PATH's ROE for hearing and settlement proceedings & accepted proposed	50 basis points (of 50) (for RTO participation)	X	X	X	X	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
	settlement for formula rates)							
Southern California Edison Company (ER08-375-000)	2008	The Commission accepted revisions to its Transmission Owner Tariff to reflect proposed changes to its transmission revenue requirement and transmission rates to implement CWIP rate incentives (from order EL07-62-000 in 2007), suspended them for a nominal period, subject to refund and subject to the outcome of a paper hearing.						
Westar Energy Inc. (EL08-31-000 and ER08-396-000)	2008	100 basis points (of 100) for Wichita-to-Reno-to-Summit Line, Denied for Reno-to-Summit Line, and Denied for Swissvale	N/A	N/A	N/A	N/A	X (Over 15 years) for Wichita-to-Reno-to-Summit Line ONLY	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
The Nevada Hydro Company, Inc. (ER06-278-000, et al.)	2008 (Denied Rehearing in Nov. 2010)	ROE "set within the upper end of the zone of reasonableness" TBD for the TE/VS Interconnect and Denied for LEAPS	Denied	Denied	N/A	X (50% debt/ 50% equity)	N/A	N/A
Startrans IO, L.L.C. (ER08-413-000 and ER08-413-001) (conditional grant)	2008 (Affirmed on rehearing in Nov. 2010)	Allowed 13.5% ROE instead of any adders because it was a newly formed public utility *Denied request for acquisition adjustment	N/A	Denied	N/A	N/A	N/A	N/A
Pacific Gas and Electric Company (EL08-24-000)	2008	Deferred Decision pending additional studies by PG&E	X	Deferred Decision	X	N/A	N/A	N/A
PPL Electric Utilities Corporation, Public Service Electric and Gas Company (EL08-23-000)	2008	125 basis points (of 150) for Susquehanna Line (allowed to assign to affiliates) and 50 basis points	X (allowed to assign to affiliates)	X (allowed to assign)	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
		(of 50)(for continued membership in PJM) (cannot assign)						
Virginia Electric Power Company (ER08-92-000, et al.	2008	50 basis points (of 50) (for RTO participation) but Denied increase of base-level ROE	N/A	N/A	N/A	N/A	N/A	N/A
Duquesne Light Company (EL06-109-000, et al.) (accepting the settlement resolving issues from 2007 order)	2008	50 basis points (of 50) (for continued RTO membership) and 100 basis points (of 150) for DTEP (including all TOI upgrades)	X	X	X	N/A	N/A	N/A
Northeast Utilities Service Company (ER08-966-000)	2008 (Denied Rehearing in Jan. 2009)	50 basis points (of 50) (for adv. tech. – conditional grant) and Granted waiver of the 12/31/08	N/A	N/A	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
		termination date for 100 basis points granted in Op. 489						
Pepco Holdings, Inc. (ER08-686-000)	2008	150 basis points (of 150) for multiple projects	N/A	N/A	N/A	N/A	N/A	N/A
Virginia Electric Power Company (ER08-1207-000 and -001)	2008	150 basis points (of 150) for 4 projects & 125 basis points (of 125) for 7 projects	N/A	N/A	N/A	N/A	N/A	N/A
New York Regional Interconnection, Inc. (EL08-39-000) (conditional grant)	2008	50 basis points (of 50) (for RTO partic.), 100 basis points (of 100) (for Transco formation), and 125 basis points (of 250) (for transmission investment and advanced technologies)	N/A	N/A	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Duquesne Light Company (ER08-1402-000)	2008	150 basis points (of 150) for the Brady Project	N/A	X	N/A	N/A	N/A	N/A
Central Maine Power Co. (EL08-74-000) (conditional grant)	2008 (Denied Rehearing in May 2010)	125 basis points (of 150)	X	X	N/A	N/A	N/A	N/A
PacifiCorp (EL08-75-000)	2008	200 basis points (of 250)	X	N/A	N/A	N/A	N/A	N/A
Southern Indiana Gas & Electric Company (EL08-82-000 and ER08-1468-000)	2008	N/A	X	X	N/A	N/A	N/A	N/A
Pepco Holdings, Inc. (ER08-1423-000)	2008	150 basis points (of 150) for MAPP project	X	X	N/A	N/A	N/A	N/A
Northeast Utilities Service Company and National Grid USA (ER08-1548-000)	2008	125 basis points (of 150)	X	X	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Central Maine Power Company and Maine Public Service Company (EL08-77-000) (conditional grant)	2008	150 basis points (of 150) for Maine Power Connection Project	X	N/A	N/A	N/A	N/A	N/A
Tallgrass Transmission and Prairie Wind Transmission (ER09-35-000 and ER09-36-000	2008	150 basis points for each project, up to 50 basis points for participation in SPP, and denied 50 basis points for adv. tech.	X	X	X	X	N/A	N/A
Commonwealth Edison and Commonwealth Edison of Indiana (EL08-78-000)	2008 (Denied Rehearing in June 2009)	Denied the 200 basis points that were requested	N/A	N/A	N/A	N/A	N/A	N/A
NSTAR Electric Company (ER09-14-000 and	2008 (Affirmed on	Granted waiver of the December 31, 2008	N/A	N/A	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
ER09-14-001)	rehearing in April 2009)	termination date for the 100 basis points granted in Opinion 489 (above) for Phase II, Denied the 100 basis points requested for Carver and the Barnstable Projects, and Denied the 46 basis points requested for adv. tech.						
Public Service Electric and Gas Company (ER09-249-000)	2009 (Denied Rehearing in Apr. 2010)	150 basis points (of 150) for its portion of MAPP Project	X (allowed to assign to affiliates)	N/A	N/A	N/A	N/A	N/A
ITC Great Plains (ER09-548-000)	2009	up to 50 basis points (of 50) for participation in SPP, and 100 basis points (for independence as Transco)	X	X	X	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Pioneer Transmission (ER09-75-000 and ER09-75-001)	2009 (Denied Rehearing in Jan. 2010)	50 basis points (of 50) (for membership in a RTO), 150 basis points (of 150) for new transmission, and Denied the 50 basis points for adv. tech.	X	X	N/A	N/A	N/A	N/A
Trans-Allegheny Interstate Line Co. (ER09-590-000)	2009	Denied TrAILCo's request for authorization to implement a 12.7 percent incentive ROE for the replacement of autotransformers and the upgrade of associated equipment at American Electric Power's Kammer Substation (Kammer Project). TrAILCo had not demonstrated how the scope, effect and risks or challenges of the Kammer Project warrant an incentive ROE.						
Green Power Express LP (ER09-681-000)	2009 (Denied Rehearing in May 2011)	10 basis points (of 10) (for new transmission), 100 basis points (of 100) (for being a Transco), 50 basis points (of 50) (for RTO membership)	X	X	X	X (by creating an initial regulatory asset)	N/A	X (by creating an initial regulatory asset)
Baltimore Gas and Electric Company (ER09-475-000)	2009 (Denied Rehearing in Mar. 2010)	150 basis points (of 150) for its portion of MAPP Project	X	N/A	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Central Maine Power and Maine Public Service Co. (EL08-77-001)	2009	The Commission granted a motion to lodge evidence that the Aroostook Wind Energy Project, which was to be connected to the grid in southern Maine by the Maine Power Connection Project, has been discontinued. In light of the cancellation, the Maine Power Connection Project no longer exists in the form that the Commission considered when it previously authorized transmission rate incentives therefore its sponsors will have to submit a new filing.						
Green Energy Express (EL09-74-000) (conditional grant)	2009	50 basis points (of 50) for participation in a qualifying Transmission Organization, 100 basis points (of 100) (for status as a Transco), and 50 basis points (of 50) (for new transmission)	X	X	X	X (50% debt/ 50% equity)	N/A	N/A
Citizens Energy Corp, Docket No EL10-3-011	2009	N/A	X	N/A	N/A	X (50% debt/ 50% equity)	N/A	X
Southern California Edison Co. (EL10-1-000) (conditional grant)	2009	100 basis points (of 150) for Eldorado-Ivanpah Transmission Project	X	X	N/A	N/A	N/A	N/A
Otter Tail Power Co. (ER10-183-	2009	N/A	X	X	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
000) (conditional grant)								
Great River Energy (ER10-147-000, ER10-147-001, and ER10-147-002) (conditional grant)	2010	N/A	X	X	N/A	X (80% debt/ 20% equity)	N/A	N/A
Western Grid Development, LLC (EL10-19-000) (conditional grant)	2010	195 basis points (of 195) (total)	Denied	X	N/A	X (50% debt/ 50% equity)	N/A	X (by regulatory asset)
PJM Interconnection, L.L.C (ER11-1985-000)	2010	N/A	Denied (and denied authority to assign)	Denied (denied authority to assign)	N/A	N/A	N/A	N/A
Central Transmission, LLC (EL11-21-000)	2011	<u>50 basis points</u> (of 50) (for RTO membership)	X	N/A	X	N/A	X (30-year depreciable life for rate recovery)	N/A
Atlantic Grid Operations A-E LLC (EL11-13-000)	2011	<u>50 basis points</u> (of 50) (for RTO membership), <u>100 basis points</u>	X	X	N/A	X (40% debt/ 60% equity)	N/A	X (by regulatory

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
(conditional grant)		(of 150) (for new transmission), <u>50 basis points</u> (of 50) (for being a Transco), <u>50 basis points</u> (of 50) (for adv. tech.)						asset)
Ameren Services Company (EL10-80-000) (conditional grant)	2011	N/A	X (allowed to assign to affiliates)	X (allowed to assign)	X	X (40% debt/ 60% equity)	N/A	N/A
NECPUC (EL08-69-001)	2011	The Commission denied rehearing of a September 2008 order that rejected a complaint seeking to prevent New England transmission owners from applying ROE adders to project costs in excess of those estimated at the time the incentive was approved.						
Desert Southwest Power, LLC (EL10-54-000)	2011	150 basis points (of 150). Denied request for any of these incentives to apply to a second circuit.	X	X	N/A	X (50% debt/ 50% equity)	N/A	N/A
Public Service	2011	N/A	X	X	N/A	N/A	N/A	N/A

Utility/Order	Order Year	ROE Adders	Abandoned Plant	CWIP	Pre-commercial Operation Costs	Hypothetical Capital Structures	Accelerated Depreciation	Deferred Cost Recovery
Electric and Gas Company (ER11-3352-000)			(Only as to 3 of 5 projects and allowed to assign to affiliates)	(Only as to 3 of 5 projects and allowed to assign to affiliates)				
Northeast Transmission Development, LLC (EL11-33-000) (conditional grant)	2011	50 basis points (of 50) (for RTO membership)	X	N/A	N/A	N/A	X (30-year depreciable life for rate recovery)	X (by regulatory asset)

ATTACHMENT B

STATEMENT OF JIM TRACY

SEPTEMBER 1, 2011

STATEMENT OF JIM TRACY

1. My name is Jim Tracy. I joined the Sacramento Municipal Utility District (SMUD) in 1989 and have served as SMUD's Chief Financial Officer (CFO) since 2004. I oversee the Accounting and Treasury departments and am responsible for overall risk management. I coordinate the development of SMUD's long-term business plan and its integration with the annual operating budget. One of my current duties as CFO is evaluating transmission investments and funding the projects approved by SMUD's elected Board of Directors. Prior to becoming CFO, I served as Director of Business Planning and Budget and as Treasurer.

2. Before coming to SMUD, I served as a principal analyst for eight years with R.W. Beck and Associates in Sacramento. I have also worked for the Missouri Public Service Commission. I hold a bachelor's degree in business administration and a master's degree in economics from the University of Missouri at Columbia.

3. I have been asked to address several issues raised by the Commission's Notice of Inquiry in *Promoting Transmission Investment Through Pricing Reform*, Docket No. RM11-26-000. My Statement is structured to cover five areas. The first section addresses the difficulty in measuring the effectiveness of the Commission's existing transmission incentive rate policies. The second section discusses what I have observed regarding the relative importance of risk-reducing mechanisms and those that enhance allowed returns in promoting needed transmission expansion. Third, I discuss how incentive rate structures – and in particular, higher return allowances for new transmission projects -- can influence the deployment of a utility's finite investment dollars. The fourth section discusses why enhanced return allowances, if permitted at all, should be applied only to project estimates, not the ultimate costs of a new transmission project. Last, I discuss how, in appropriate circumstances, diversification of risk by joint ownership of transmission facilities can obviate the need for rate incentives.

Difficulties in Measuring the Impact of Order No. 679 Policies

4. The NOI poses a series of questions at PP15, 17, 20, 25, 26, 28, 29, 31, 33, 35-39 and 44 and asking for documentation of the impact the Commission's Order No. 679 incentive rate policies have had on achieving the goals of FPA Section 219 – namely improving reliability and reducing congestion to reduce the cost of delivered power. One question (P 15) asks, for example, "Have the incentives granted to transmission projects had an impact on consumer rates and service, including impacts related to reliability and the reduction of congestion?" The short answer to this general question is that it is nearly impossible to say, after the fact, whether the Commission's incentive rate policies have had a positive impact on reliability or consumer prices. I reach this conclusion for several reasons.

5. It is my understanding that, in considering the approach it ultimately adopted in Order No. 679, the Commission rejected comments urging it to adopt a "but for" test as a qualification for obtaining incentive rate treatment. Under such a test, an applicant seeking rate incentives would have to have shown that its project would not be developed but for the grant of incentives. The Commission also rejected comments proposing that applicants for incentive rate treatment quantify the benefits of their projects in relation to the costs of the requested incentives.

Whatever the merits of those policy choices, it is not now possible, in light of those past choices, to measure Order No. 679's effectiveness in improving transmission reliability or reducing congestion to reduced delivered power costs. The reasons are interrelated.

6. Take first, the absence of a "but-for" test. Under a "but for" test, the applicant would have been required to demonstrate that the incentives sought were needed to ensure the project's undertaking and completion. Since the Commission did not demand such evidence before granting incentives, there is no way to measure, after the fact, whether a project would have gone forward absent the granting of incentives. Nor is it possible to know whether the incentives resulted in earlier in-service dates for such projects, since Order No. 679 incentives, as I understand it, have not been tied to meeting specific in-service dates.

7. Adding to the hurdles in assessing whether Order No. 679 has had a measurable positive impact is the difficulty in isolating the impact of incentives granted from other factors that have been at work in the economy in the years since Order No. 679 issued. The Commission notes in the NOI (at P 5) that the purposes to be achieved by Order No. 679 were to improve reliability and to lower delivered power costs (through reduced congestion). One key difficulty in measuring the impact of transmission rate incentives on achieving these objectives, particularly in the absence of a "but for" test, is that the substantial slow down in the nation's economy tended to produce the same types of impacts. Reduced economic activity has dampened the demand for electricity. Reduced demand for electricity results in less stress on the transmission grid (enhancing reliability). Moreover, because it also reduces congestion, reduced demand has a dampening effect on electricity prices. We have seen both effects in California over the last few years.

8. Similarly, because the Commission's Order No. 679 test did not demand quantification of benefits in relationship to the costs of the incentives, there is no way to determine whether any improvements in reliability or reduction in delivered power costs that may have occurred since Order No. 679 issued were either anticipated to result from the incentives granted or were actually a realized benefit. I understand that, in a number of cases the Commission has applied the Order No. 679 presumption that, because a project had been approved in a regional planning process, it would either improve reliability or reduce delivered power costs. But the Commission itself did not require a demonstration of the degree of reliability improvement or the extent to which delivered power costs would decline as a condition of granting the incentives. Nor did it require the applicants to demonstrate whether the costs of the incentives would be exceeded by the benefits of improved reliability or lower delivered power costs. For example, even if lower congestion on a transmission system could be tied to a transmission project that had received incentive rate treatment, and even if it could be established that the incentives had made the project possible, the costs of the project might have exceeded the benefits of reduced congestion.

9. I would also note that while there has been a significant amount of new transmission plant constructed in the years since Order No. 679 was issued, the fact that construction of new transmission facilities *coincided* with the post-Order No. 679 time period does not establish a *correlation* between new construction and the award of transmission incentives. Most new transmission built in the United States has been and continues to be constructed by public utilities. Many of these utilities have a public utility obligation to provide reliable service and this ongoing obligation may well account for a significant amount of that construction. I also

understand that other public utilities have agreed by contract to construct new transmission projects included in regional plans approved by their regional transmission organizations. In such circumstances it would be impossible, after the fact, to determine what impact any incentive rate treatment granted had on the transmission owner's decision or ability to proceed with the project, as they might well have been required to undertake the project even in the absence of incentives.

10. While it is not possible to determine whether the incentives the Commission granted have had a positive impact, I cannot, for the same reason, say with certainty that the incentives have *not* encouraged the construction of new transmission projects. But even if one simply *assumes* a cause and effect relationship between the incentives granted by the Commission and the projects built thereafter, it does not follow that the net impact was necessarily beneficial. As I indicated previously, the costs of the incentives may have been greater than the benefits. Even if the costs did not exceed the benefits, the costs of the incentives were almost certainly more than needed. As I note later in my statement, it would be the unusual case where rate of return adders were needed to spur a project that could not have been aided by more modest risk-reducing measures such as formula rates, construction work in progress (CWIP) allowances or abandoned plant protection. Yet in many instances the Commission has approved all of these risk-reducing incentives *and* granted a substantial rate of return adder as well. I also cannot dismiss the possibility that the Commission's incentive rate orders have resulted in excess transmission capacity. It would be useful to measure whether projects that have received incentive rate treatment from the Commission have been undersubscribed, underutilized or even overbuilt. Lower spot prices might result from excess transmission capacity but these lower prices might not offset the cost of unneeded transmission capacity. I do not assert that the Commission can determine whether the phenomenon of undersubscription or overbuilding has been caused by the Commission's incentive rate policies for the same reasons that one cannot measure whether these policies have had a positive impact. But I make the observation instead to illustrate the futility in trying to measure Order No. 679's success. Going forward any new incentive rate policy should guard against incentives to overbuild that might result from inadequately tailored incentives.

The Relative Importance of Risk-Reducing Versus Profit-Enhancing Incentives

11. Since the issuance of Order No. 679, the Commission on many occasions has granted applicants multiple rate incentives for the same project – abandoned plant cost recovery, CWIP, formula rates, hypothetical capital structures and enhanced return allowances. All but the last two are means to reduce an applicant's risk. The latter two mechanisms enhance the applicant's rate of return allowance, and hence its profits. Based on my knowledge of the industry, it would be an unusual case in which an enhanced return allowance would be necessary to ensure the construction of needed transmission projects. Moreover, it is difficult to imagine a case in which it would be necessary to grant an applicant an enhanced return allowance – a mechanism that is presumably tied to elevated risk of capital recovery – where the applicant also receives incentive rate treatments that reduce its risk of capital recovery.

12. Over the years, in my capacity as SMUD's CFO, I have been involved in financing a number of large infrastructure projects, including transmission, distribution and generation facilities. It has been my experience that the lending institutions underwriting these types of projects have as their first interest the certainty of long term cash flow potential of the projects, not the specific rate of return the applicant will be able to earn on the project. The applicant's

concerns are not dissimilar. Although the role of merchant transmission companies may well expand, most of the entities that will be constructing new transmission facilities will continue to be utilities. And, whether public or privately-owned, their principal motivation for constructing new transmission facilities will be to meet their obligations as utilities, as participants in regional planning organizations and signatories to agreements that obligate them to construct new transmission. They will not be building transmission on "spec" on the enticement of enhanced returns. Nor do I think that lenders will be influenced to finance exceptionally risky projects because the transmission owners have received enhanced return allowances. What will influence lenders in such circumstances is the availability of mechanisms that reduce the transmission owner's risk of revenues being interrupted at some point during the projected recovery period. In most cases – the vast majority, in fact – I should emphasize that no special rate treatment is or should be needed – most transmission projects are routine and even large undertakings are part and parcel of the responsibilities of electric utilities.

13. In prior cases approving a combination of risk-reducing rate incentives and return adders, I understand the Commission to have stated that while risk-reducing mechanisms like CWIP and abandoned plant cost protection can reduce investment risk, they may not offset the additional siting, construction, regulatory and environmental risks faced by an applicant. I would urge the Commission to reconsider whether these are really separate risks at all. In my experience they are not. One of the largest investment risks facing a utility is the risk that capital invested in a project will fail to be included in rate base and be written off. That failure is likely to be because of hurdles in siting, construction, environmental conditions or other regulatory requirements. I do not see why abandoned plant cost protection does not fully protect the utility against these types of risks.

14. While my experience is not as a merchant transmission owner, my views on the relative importance of risk-reducing mechanisms and rate of return adders are the same when applied to merchant transmission projects. To the extent merchant transmission owners are single asset entities, regulators might be convinced to grant such entities a higher base rate of return allowance than the return allowances of their more traditional utility counterparts because they are considered inherently more risky. If this is the case, then there is no need to grant these entities an enhanced return adder because the base return already incorporates consideration of their greater risk. And I understand that at least one merchant transmission developer, LS Power, has voiced its concern that the biggest hurdle to development of merchant transmission projects is not the absence of adequate rate incentives, but the barriers to merchant transmission that they say some incumbent utilities have erected.

Unnecessary Rate Incentives Can Skew the Deployment of a Utility's Finite Investment Dollars

15. The Commission's NOI (at Q8) posits the question whether the incentives granted to transmission projects have had "an impact on investment patterns in the electricity industry" and whether incentives, as a general matter, affect "the allocation of investment capital among transmission, generation and distribution facilities." As with other questions about the actual effects of the Commission's incentive rate policy, it is not possible to measure what actual effect its policies have had on past investment allocation decisions, due to the lack of any rigorous showing by past recipients of the need for such incentives. But I think it is fair to conclude that a

utility's investment dollars are limited and that, in certain circumstances, the availability of higher returns on transmission investments can skew a utility's investment decisions. I believe it is possible that the availability of incentives may have skewed some of the investment choices made by transmission owners eligible for incentive rate treatment under Order No. 679. Prospectively, for the same reason, transmission incentives, particularly higher return allowances, can, in certain circumstances, skew the utility investment decisions away from investments in generation or distribution.

16. It bears emphasis that transmission owners have finite resources and that their choice to invest in one project will limit their other investment options. That said, a utility's investment decisions will in most instances be driven by system needs, not return allowances. Let me explain.

17. When a utility develops an overall expenditure plan, some investments are not discretionary—they have to be made because of the utility's obligation to serve (e.g., to serve new loads or to replace failed equipment). Other investments are made to address potential reliability impacts due to aging infrastructure (they have some probability of failure) These are more discretionary investments where the utility is aware of some probability of problems, but they can choose to defer them, at least in the short term. In the former case a utility cannot forego investment in distribution plant needed to address imminent reliability or new customer issues in order to earn higher returns on less critical transmission infrastructure. In the latter case the utility has more flexibility to choose the investment option that offers the higher return.

18. Utilities will typically spend money to replace or add facilities to stay ahead of the curve and avoid problems before they occur, because reliability is a high priority. But these are still discretionary investments in the sense that they can be deferred for some period of time without risking acceptable service reliability. For example, a decision to replace underground distribution lines can be deferred. If this can be done and if the utility's shareholders can earn a higher return on transmission investments than on such deferred distribution upgrades or replacements, this is likely to cause a shift in the utility's use of its investment dollars. A higher-than-required ROE allowance on new transmission facilities could skew the incentives toward investment in such higher return projects even if investment in distribution facilities carrying a lower ROE might be optimal for overall reliability. This would not be desirable, particularly if incentives are made too readily available, and could encourage overbuilding of transmission capacity.

19. This problem could be even more acute given the current disparity between base ROE levels awarded by state public service commissions for state-regulated facilities and the base ROE levels this Commission has awarded for investments in facilities used to provide FPA-jurisdictional services. The table included in the attached comments in response to Question 8 of the Commission's NOI sets out certain of these state and federal ROE allowances. The addition of incentive ROE adders on top of already-higher base ROEs could further skew investment decisions.

Enhanced Return Allowances, If Permitted At All, Should Be Applied Only To Project Estimates, Not The Ultimate Costs Of A New Transmission Project

20. One concern discussed in the NOI (at P 27) is whether granting transmission developers an ROE adder for new transmission projects and applying the adder to the project's actual ultimate cost rather than its estimated cost gives the applicants a perverse incentive to increase project costs because they will earn the adder on the entire cost of the project. The Commission has asked a series of questions related to this concern at P 28, including questions about implementation of a policy to limit adders to estimated project costs: "Would this approach work in all regions of the country? What processes for developing, evaluating, and updating cost estimates must be in place within regional transmission planning processes to facilitate such an approach?" There are undoubtedly variations in regional planning processes, but the concern reflected in the questions is both valid and generic – applying incentive adders to the ultimate cost of a project is likely do more harm than good.

21. I have already explained why enhancements to rate of return allowances should only rarely be needed to facilitate construction of a transmission project – and virtually never in conjunction with risk-reducing incentives such as formula rates, CWIP or abandoned plant projection. The Commission has noted that the ultimate purpose of the incentives, as required by FPA section 219, is to benefit electric consumers by improving their service reliability and/or reducing their delivered power costs by reducing congestion. Any rate of return adder granted must be tailored to achieve that objective. Adders that would increase a utility's return whenever the costs of its transmission projects exceed its prior estimates effectively reward the utility for coming in over budget. Simply put, rewarding such behavior does not comport with the purposes of section 219.

22. I do not mean to suggest that there cannot be legitimate reasons why a project applicant's ultimate costs will exceed its estimates. During periods of rising commodity or labor costs, for example, ultimate project costs may well exceed estimates, even estimates that contain contingency factors. But human nature being what it is, a developer, without being imprudent, might well put forth less than its best efforts to contain project costs when management knows that shareholders will actually benefit if costs are *not* contained.

23. Despite likely differences in the way cost estimation processes may vary from region to region, I think there is a generic approach to this problem that transcends regional differences. There may, for example, be several stages in a regional planning process at which revised or updated estimates of a project's cost are submitted. For purposes of incentive ratemaking, however, the focus should be on estimates in existence at the time the applicant seeks incentive rate treatment. At the time an applicant seeks a rate of return adder, it should include the most recent estimate of the project's cost, whether that estimate has been submitted to a regional planning organization, a siting authority or, in the absence of such filings, to its own management. Presumably, if an applicant believes an incentive ROE adder is necessary, it has likewise concluded that the revenues produced by the adder, as applied to the then-estimated cost of the project, are sufficient to undertake the project. Where the applicant then experiences actual costs that exceed its estimates, and those costs were prudently incurred, it is my understanding of conventional ratemaking that the utility would be allowed to earn its standard return on the total cost of the facilities.

24. It seems obvious to me that there is no penalty, much less a disincentive, in limiting the adder in such cases to the project's estimated cost. When an applicant submits a request for incentive rate treatment and represents to the Commission what its estimated costs will be, it is reasonable to assume that the estimate has been made in good faith. Indeed a prudent estimate will itself likely include a substantial contingency factor to account for the inevitable changes in project scope and details as well as unanticipated problems that occur routinely in construction of a large transmission project. Since the utility would be allowed a normal return on its entire investment, limiting the adder to the project's estimated cost is just a way of quantifying how much of an incentive the Commission will allow and ensuring that the costs of the adder do not outweigh its expected benefits.

In Appropriate Circumstances, Diversification Of Risk By Joint Ownership Can Obviate The Need For Rate Incentives

25. One of the reasons frequently given by applicants for incentive rate treatment under Order No. 679 is that the project's large cost in relation to the utility's existing rate base creates cash flow problems and other substantial risks. Large new transmission projects are not a recent phenomenon made possible only by the availability of incentive rate treatment. SMUD, for example, is one of the co-participants in the California Oregon Transmission Project, a 500 kV transmission facility running several hundreds of miles in length south from the California Oregon border. SMUD's share of that line exceeded in value the cost of all of SMUD's other transmission facilities at the time it agreed to make the investment; hence, it was a very substantial transmission investment for SMUD.

26. There are undoubtedly instances where a needed transmission project cannot be financed by conventional means because, absent other arrangements, the project may represent too large an undertaking for a single transmission owner. Where that is the case, joint ownership of facilities may be a possibility. Joint ownership of a transmission project diversifies the risk of the undertaking and may obviate the need in whole or in part for transmission incentives. In my opinion, an applicant claiming the need for incentive rate treatment based on the magnitude of the risk of adding facilities that are large in proportion to its existing transmission plant should be required to demonstrate that it has considered joint ownership arrangements. The applicant should show either that it has a compelling reason for rejecting such arrangements or that such joint ownership arrangements were not feasible.

I hereby certify on this 1st day of September, 2011 that the foregoing Statement was prepared by me or under my direct supervision and that such Statement is true and correct to the best of my information, knowledge and belief.

/s/Jim Tracy

ATTACHMENT C

STATEMENT OF HANS E. MERTENS

SEPTEMBER 1, 2011

STATEMENT OF HANS E. MERTENS

1. My name is Hans E. Mertens. I am the Director of Engineering Services and Chief Engineer of the Vermont Department of Public Service, 112 State Street, Montpelier, Vermont 05620. I have served in that position since 2001. Relevant to my statement here, my responsibilities have included participation in the regional transmission planning process in New England and in the larger transmission planning initiative for the Eastern Interconnection under the auspices of the Department of Energy. I hold a bachelor of science degree in civil engineering from the New Jersey Institute of Technology and an MBA in Finance and Regulation from Rutgers University. Prior to my work at the Department I have worked for several private utilities, including the Williams Companies, Westar, Public Service Electric and Gas and Consolidated Edison Company of New York. My responsibilities included the planning, design and management of large infrastructure projects, principally gas and electric, distribution and transmission facilities. At Westar, for example, I served as Vice President – Electric Transmission Services, where I was responsible for transmission system planning, operation, and maintenance. I am presently a member of the Board of Directors of the Northeast Power Coordinating Council (NPCC). Further details of my experience and educational background are included in my attached resume.

2. I have been asked to address two interrelated issues raised by the Commission's Notice of Inquiry in this proceeding: the role of incentive return allowances in transmission planning and the relationship between transmission investment decisions and transmission cost projections. My opinions, discussed below, are informed by my education in finance and my experience participating in the regional transmission planning process in New England during my tenure at the Department as well as my experience in the planning of transmission in other regions of the country. My opinions are also informed by my similar experiences in managing construction budgets and directing construction of utility facilities. I have found that the basic investment decisions and budget management in the electric utility industry do not vary markedly from the investment approach that management applies in other industries.

3. My Statement addresses the two areas mentioned above. The first section discusses what I have observed is the relative importance of risk-reducing mechanisms and those that enhance allowed returns in promoting needed transmission expansion. Second, I discuss why enhanced return allowances, if permitted at all, should be applied only to project estimates, not the ultimate costs of a new transmission project.

Risk-Reducing Rate Mechanisms Obviate the Need for ReturnAllowance-Enhancing Incentives

4. As Mr. Tracy and Mr. Behrns note in their statements, over the last few years, the Commission has approved a number of utility filings under Order No. 679 where the applicants have requested the full range of rate incentives for a single project. The same project in many cases has been awarded abandoned plant cost recovery, construction work in progress (CWIP), formula rates, hypothetical capital structures and enhanced return allowances.

5. Both Mr. Tracy and Mr. Behrns state that the return enhancing mechanisms included in this list of incentives are essentially only hypothetical capital structures and enhanced ROE allowances. The rest of the incentive mechanisms serve to reduce risk. My experience leads me to the same conclusion that they have reached in this regard; utilities planning transmission expansion projects have a primary interest in mitigating the risks of their undertakings. If the risks are known and manageable their decision to proceed with needed transmission projects hinges less on the bonus from an enhanced return allowance. Moreover, in most instances the utilities undertake projects to meet their utility obligations, even where the projects represent very large undertakings. Utilities will certainly apply for and accept the enhanced return allowances if they are awarded, but my experience is that they would largely view these types of rate mechanisms as welcome windfalls, not as inducements.

6. One of the incentives the Commission has awarded on a number of occasions in recent years is abandoned plant cost protection. Having been involved in transmission planning decisions of public utilities, I find it difficult to believe that, having received a major risk-reducing judgment of this type, they would have any further need for return enhancing incentives in order to go forward with needed transmission projects.

7. The reason for my conclusion is straightforward. Utilities have obligations to serve their retail customers and in many regions – MISO, New England, PJM, for example – they are contractually obligated to be the providers of last resort for system reliability. Often this means giving their best efforts to construct transmission projects identified as needed in the regional planning process. I cannot see what additional benefit consumers would receive if transmission owners are awarded an enhanced return on top of risk-reducing mechanisms. Mr. Tracy states that one of the largest investment risks facing a utility is the risk that capital invested in a project will fail and that failure is likely to be because of hurdles in siting, construction, environmental restrictions and other regulatory requirements. Like Mr. Tracy, I do not see why abandoned plant cost protection does not fully protect the utility against these risks. Similarly, I don't see why an enhanced return allowance in addition to this protection would make the transmission owner try harder or work faster to complete a project. As I note in the next section of my statement, the incentive may be just the opposite – if the transmission owner is rewarded by an enhanced return on the ultimate cost of the new facilities, it can be argued that the utility will actually have an incentive to delay construction or take more costly measures solely to add to rate base.

Enhanced Return Allowances, If Permitted At All, Should Be Applied Only To Project Estimates, Not The Ultimate Costs Of A New Transmission Project

8. The NOI poses several questions about whether incentive rate treatment should be limited to estimated, rather than actual project costs, and, if so, whether that approach should be different in different areas of the country. I see no reason to grant enhanced return allowances to transmission owners based on the ultimate costs of their projects. Based on my own experience and recognizing that the capital markets for utilities are national not regional, there is no justification for any regional exceptions to such a policy. On the other hand, I think it is, and has been counterproductive for the Commission to grant incentive adders to transmission owners that allow them to earn a supranormal return on the ultimate costs of their projects. This is particularly painful during a period where transmission construction costs have been rising at

unprecedented high rates. I believe this policy has created a perverse incentive effect – it gives transmission owners *less* incentive to contain project costs and bring projects in on time on budget. In fact, it has been observed that it creates an incentive to exceed estimated costs since the transmission owner will earn the supranormal return on the ultimate cost of the project which includes the effect of wild inflation and ineffective project management.

9. There are, of course, many reasons why the actual costs of a transmission project may exceed the estimated costs. Imprecision is the very nature of an estimate. But my uniform experience in the gas and electric industries is that when utilities make decisions to invest in new infrastructure projects, including transmission projects, they do so based on their estimates of the costs they expect to incur. Those projects are approved because they meet internal financial hurdle rates based on the same estimates that they initially advance to the FERC for approval. There may be some very limited instances in which the availability of an incentive return provides the utility with the impetus to undertake a transmission investment, but the decision to proceed is based on the estimated cost of the project and the expected return on that estimated cost. Further, it is a widespread practice for utilities contemplating infrastructure projects to incorporate significant contingency factors into their estimates. The earlier the stage of the estimate, the larger the contingency. In New England, at the earliest stages of a transmission project, the contingency factor can be as high as 200 percent. In other words, the estimated cost figure provided for planning purposes is triple the basic estimated cost. As projects move into later planning stages, both scope of work and estimates are revised, and the contingency factor declines. However, rarely would contingencies fall below 20% in the proposal stage. This approach is not unique to New England transmission owners.

10. Unlike gas pipeline projects that fix construction costs during the open season process, the contingent nature of electric utility's cost estimate almost always allows full recovery of project costs. There is no reason that a utility would logically conclude that it needs an enhanced return on the ultimate cost of the project before it will proceed. As I mentioned earlier, the danger of endorsing incentive rate treatment that would allow an enhanced return on the project's ultimate cost, is that if such an approach provides any incentive, it is an asymmetrical incentive to exceed estimates. Again, as long as the electric utility has acted prudently, it will continue to receive a normal return on the actual costs of its project, even where those costs substantially exceed estimates. My experience and training leave me certain that no rational utility would turn down an opportunity to invest in a needed transmission project that allowed it a supranormal return allowance on its estimated project costs even if it were allowed only a normal return on project costs that exceed its estimates at time of approval.

11. I agree with Mr. Tracy that, despite likely differences in the way cost estimation processes may vary among regions, there is a generic policy proscription and it is pretty straightforward. As he notes, there may be several stages in a regional planning process at which revised estimates of a project's cost are submitted. These differences become irrelevant if the Commission's policy is to limit the applicant to enhanced returns based on the estimates of project costs in existence at the time the applicant seeks incentive rate treatment. Mr. Tracy proposes, and I agree, that, at the time an applicant seeks a rate of return adder, it should include the most recent estimate of the project's cost it has made, whether that estimate has been submitted to a regional planning organization, a siting authority or, in the absence of such filings, to its own management.

12. The logic of such a policy is simple. The utility's investment decision, as I stated earlier, will be – *has to be* – based on its estimate of project costs. If it has applied to the Commission for incentive rate treatment its application will necessarily have been based on its estimate of project costs and, implicitly, its conclusion that an enhanced return applied to that estimate will encourage it to go forward with the project. Where the transmission owner experiences actual costs that exceed its estimate, and those costs were prudently incurred, I share Mr. Tracy's understanding of conventional ratemaking that the utility would be allowed to earn its standard return on the total cost of the facilities. As Mr. Tracy states, since the utility would be allowed a normal return on its entire investment, limiting the adder to the project's estimated cost is just a way of quantifying how much of an incentive the Commission will allow and ensuring that the costs of the adder do not outweigh its expected benefits. A cause and effect relation does not exist by paying the incentive as described above. Adjusting how incentives are paid is a matter of critical importance to consumers that are being unnecessarily burdened by bonuses that are unlikely to improve the reliability of the electric grid.

I hereby certify on this 1st day of September, 2011 that the foregoing Statement was prepared by me or under my direct supervision and that such Statement is true and correct to the best of my information, knowledge and belief.

/s/Hans E. Mertens

ATTACHMENT D

STATEMENT OF RON BEHRNS

SEPTEMBER 1, 2011

STATEMENT OF RON BEHRNS

1. My name is Ron Behrns and I am Director of Finance, Economics and Business Administration for the Vermont Department of Public Service (DPS). My business experience includes telecommunications, regulation, entrepreneurial business ventures and domestic and international consulting services. Functionally, my business experience includes policy formulation, strategic planning, finance, regulation, taxes, accounting and marketing. I hold a B.S. degree in Accounting and Management Science from Eastern Illinois University and an M.B.A. degree with concentrations in Finance and Economics from Illinois State University. Additionally, I hold CMA certification; serve on the Finance and Accounting Sub Committee of NARUC and am a member of the Institute of Management Accountants, the Society of Utility and Regulatory Financial Analysts, the International Association for Energy Economics and Tax Executives Institute.

2. I have been asked to address two issues raised by the Commission's Notice of Inquiry in this proceeding. The first section of my statement discusses why, in my view, where ratemaking incentives are appropriate to encourage needed transmission projects, risk-reducing mechanisms will nearly always suffice and why rate incentives that offer return adders will only rarely be justified to promote needed transmission expansion. The last section of my statement follows on my first. There, I discuss why, in those limited cases in which return adders are permitted, they should only be applied to the applicant's project cost estimates – to avoid giving transmission owners not merely a disincentive to contain project costs, but an inherent incentive to exceed estimated project costs.

Where Risk-Reducing Rate Incentives are Appropriate and Available, Return Allowance-Enhancing Incentives Will Rarely, if Ever, be Justified to Encourage Needed New Transmission Projects

3. Mr. Tracy notes in his affidavit that, since issuance of Order No. 679 the Commission, on many occasions, has granted applicants multiple rate incentives for the same project – abandoned plant cost recovery, construction work in progress (CWIP), formula rates, hypothetical capital structures and enhanced return allowances. I agree with him that all but the last two are means to reduce an applicant's risk. I also agree with him, based on my own knowledge of the industry, that enhanced return allowances would only rarely be necessary to facilitate the construction of needed transmission projects. From the perspective of the capital markets, it is doubtful that enhanced return allowances on equity would have any measurable effect on facilitating needed transmission projects. And, like Mr. Tracy, in my opinion it will never be necessary to grant an applicant an enhanced return allowance on top of incentive rate treatments that reduce its risk.

4. Over the years, in my capacity as a financial analyst for the DPS, I have reviewed utility filings that involved the financing of significant sized transmission, distribution and generation facilities. Historically, utilities have undertaken these projects without seeking special incentive rate treatment. This is not to say that some projects have not posed greater risks than others, but the companies' own rate of return requests have been based on their overall risks. Like Mr. Tracy, my experience with review of capital markets has been that their prime

concern is whether the applicants will have a sufficient security of a revenue stream to pay interest on borrowed funds and sufficient dividends to attract investors. This security, particularly for utilities, is found either in the existence of long-term contracts for use of the capacity of their transmission or generation facilities or in the stable nature of their utility loads. In the case of transmission, if the project is necessary for reliability, for example, there is much less risk involved in the undertaking than for other non-utility investments. I also agree with Mr. Tracy that for public utilities, the principal motivation for constructing new transmission facilities will be to meet their obligations as utilities, as participants in regional planning organizations and signatories to agreements that obligate them to construct new transmission.

5. To be sure, there are risk-reducing mechanisms that can facilitate the construction of new transmission projects. Where regulators allow formula rates or CWIP or abandoned plant cost recovery it would be easier to convince lenders to supply capital for large projects. But even many large projects, in my experience, are routine and no special incentive rate treatment would be demanded by the markets before these projects could be undertaken. That is principally because the markets will recognize the stability of transmission investments – there is typically little competition for the provision of transmission service and financial markets recognize the stable nature of transmission investments. Where these investments are approved as part of a regional planning process this will provide even further assurance to the financial markets.

6. I have also been asked to address a view expressed in some earlier Commission cases that risk-reducing mechanisms like CWIP and abandoned plant cost protection may not offset the additional siting, construction, regulatory and environmental risks faced by an applicant. Like Mr. Tracy, I do not believe these are separate risks. In my experience they are not. One of the largest investment risks facing a utility is the risk that a project will fail. Obstacles in siting, construction, meeting environmental conditions or satisfying other regulatory requirements relate to the ability of the applicant to complete the project successfully. If applicants are granted abandoned plant cost protection these types of risks are, by definition, covered. For that reason I see no justification for granting both risk-reducing and return enhancing incentives.

7. My opinion about the lack of justification for both ROE adders and risk-reducing incentives applies equally to merchant generation. The proper ROE allowance for a merchant generator will be reflected in its base ROE allowance. As a merchant, rather than utility, undertaking it will inherently face greater risk, but that risk will be reflected in the ROE allowance. If additional incentives are needed to encourage merchant transmission, they would logically take the form of risk-reducing measures, not inflated returns.

Enhanced Return Allowances, If Permitted At All, Should Be Applied Only To Project Estimates, Not The Ultimate Costs Of A New Transmission Project

8. Several years ago, New England regulators filed a complaint at FERC expressing concern that sharply rising transmission costs had made it unreasonable to apply ROE adders to the ultimate costs of new transmission projects in New England rather than to the estimated cost of those projects at the time the applicants had sought approval of the adders at the Commission. The nature of their concern was that applying the adder to the ultimate cost of a transmission project would actually reward transmission owners for exceeding the estimated costs of their

projects, giving them a disincentive to contain costs. While the Commission denied their complaint on grounds that the issue should have been raised when the transmission owners had first applied for the incentives, Commissioner LaFleur noted in her concurrence that the issue the state regulators had raised was an important one and that it would be explored in the NOI. I have been asked to address this issue in my affidavit.

9. One question posed by the Commission is whether a policy limiting transmission ROE adders to the estimated cost of a project would work in all regions of the country. In my opinion, regional differences in the transmission planning process have little to do with the issue. As Mr. Mertens notes in his affidavit, it is the nature of the transmission planning process that entities developing transmission projects will incorporate contingency factors into their estimates of project costs. I have already expressed my reasons for concluding that ROE adders will only rarely be needed to facilitate the construction of new transmission projects. But even in those cases in which a transmission provider can justify the need for an ROE adder, it is difficult to see why it would be necessary to apply an adder to the ultimate cost of a transmission project, even where that cost greatly exceeds the transmission owner's estimate at the time it applied for incentive rate treatment.

10. It is my experience that those financing a project are ultimately interested in the borrower's ability to repay the money it borrowed. An enhanced return on equity applied to the ultimate cost of the project is, in my judgment, of no material importance to the financial markets. They would be interested in the risk of project failure or whether the expected revenue stream is sufficient. As for the transmission owners, I do not see how limiting the adder to the estimated cost of the project at the time the application for incentive rate treatment is made could upset their reasonable expectations. Absent a showing of imprudence, the transmission owner would still be allowed to earn the normal return on the ultimate cost of the project. I have been involved in many rate cases as a financial analyst. The normal return allowance, in my experience, is itself intended to be sufficient to attract the necessary capital and to allow the utility to operate profitably. It makes no sense, even where some *additional* return allowance may be needed to encourage the utility to undertake a needed transmission project, to apply that adder to the ultimate cost of a project, particularly where labor and material costs are rising. This simply rewards the transmission owner, not for added risks, but for undertaking what it was presumably willing to undertake at the project cost it estimated at the time it sought incentive rate treatment.

11. More importantly, applying the adder to ultimate project costs does not only unnecessarily increase costs to consumers, it creates disincentives to cost containment. I have been involved in many rate cases over the years involving large additions to utility plant, both transmission and generation. The primary motivation of the applicants in these cases to add these facilities is their utility obligation to provide reliable service and the risk that regulators will penalize them if they do not fulfill these responsibilities. In a time of rising transmission construction costs, such as New England has seen over the last few years, rates should be structure to create incentives for the transmission owners to contain costs without compromising reliability. But the Commission's current policy has the opposite effect. In my experience there is a range of utility conduct that would be considered prudent by regulators. But within this range, the utility has considerable discretion in its business decisions. If utility management knows that it will be allowed a higher return on the costs of a new transmission project than the

normal ROE allowance, where there is a close decision about how to proceed on a project, it will have little disincentive to choose the more expensive approach. Worse, it will actually have the incentive to take the more costly route, as long as its decision is broadly within the range of a utility's discretion. It would be unsound regulatory policy, in my opinion, to reward the utility for such a decision. Yet that is precisely the effect of a policy that would allow transmission owners to earn ROE adders on the ultimate costs of their projects.

I hereby certify on this 1st day of September, 2011 that the foregoing Statement was prepared by me or under my direct supervision and that such Statement is true and correct to the best of my information, knowledge and belief.

/s/Ron Behrns