How Can FERC Improve the Transmission Incentive Policy?

Ways to Improve Clarity, Transparency, and Performance

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Online Access

This paper can be found online at http://www.nrri.org/pubs/electricity/NRRI_FERC_trans_incentives_sept09-12.pdf.

Executive Summary

By authority of the Federal Power Act, the Federal Energy Regulatory Commission (FERC) has jurisdiction over interstate electricity sales, including rates and cost allocation for transmission service. Based on this jurisdiction and mandates from the Energy Policy Act of 2005, FERC issued Order 679 (2006). That issuance provided a series of potential incentives to transmission owners.

In addition to potentially spurring transmission investment, FERC's transmission incentives increase near-term customer costs. For instance, the provision of 200 basis points of ROE incentives for a one-billion-dollar project depreciated over 30 years with a 50% debt and 50% equity capital structure increases customer costs (including additional taxes) by more than $200 million dollars over the project's life. By describing FERC's standards and evaluation practices, this paper will decrease the uncertainty of customer cost effects in different scenarios. It will also enable readers to evaluate FERC's transmission incentive policy and intervene effectively in future cases. Additionally, this paper recommends policy alternatives that could improve predictability and reduce customer costs.

In the three years since Order 679's issuance, FERC has provided additional guidance on some aspects of this policy, though certain ambiguities persist. FERC has partially clarified the standards it applies with the "**nexus**" **test** to determine incentive eligibility, although the exact meaning and requirements of this test remain uncertain. FERC has also developed standard return-on-equity (ROE) incentives for participation **in regional transmission organizations** (RTOs) and the formation of "**Transcos**" (corporations that own only transmission assets). FERC's evaluation criteria for generic ROE incentives (those not associated with "**advanced technologies**," RTO participation, or Transco formation) remain unclear and case outcomes are unpredictable.

Part I of this paper provides background, including FERC's mandates from the Energy Policy Act of 2005 and its rulings in Orders 679 and 679-A. Part II discusses the process by which applicants can demonstrate that they should receive incentives. Part III describes how FERC determines whether projects ensure reliability or reduce congestion and how it has applied the nexus test to allow or deny various incentives. Part IV critiques FERC's transmission incentive policy and provides recommendations for improving it.

The paper reaches the following conclusions about FERC's provision of transmission incentives:

- To pass the **nexus test**, applicants, in most cases, must demonstrate that their projects are **not** "**routine**" by describing their **scope**, **positive effects**, and **risks and challenges**. The Commission also considers the use of advanced technology and the facilitation of renewable energy generation when determining whether projects are routine.

- **Generic ROE** incentive adders, although usually between 100 and 150 basis points, are not predictable.

- The **advanced technologies**, **RTO participation,** and **Transco formation incentives** have been 50, 50, and 100 ROE basis points respectively.

- Most approved **hypothetical capital structure** incentives, which projects can utilize only during the construction period, have consisted of 50% debt and 50% equity.

The paper also provides the following recommendations to FERC to improve the policy's rigor and transparency:

- Require applicants to provide further quantification of project benefits. Use a basic cost-benefit analysis to ensure that a project's reliability and congestion relief benefits could equal or exceed its incentives' ratepayer costs.

- Replace the RTO participation incentive with an ROE incentive for projects located in regions with acute reliability or congestion problems.

- Utilize and disclose a rigorous methodology by which to determine generic ROE incentives, which FERC should establish in conjunction with the base ROE (the ROE absent incentives).

- Reduce final ROE levels (the base ROE plus incentives) by a predetermined amount for each risk-reducing incentive.

- Explain the rationale for the levels of RTO participation, advanced technologies, and Transco formation ROE incentives. Consider varying incentive levels based on the type of RTO, Transco, or advanced technology.

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How Can FERC Improve the Transmission Incentive Policy?

I. Background on FERC Authority and Incentive Orders

A. FERC regulatory authority

Section 824 of the Code of Federal Regulations (CFR), drawing authority from the Federal Power Act, provides FERC with jurisdiction over interstate sales of electricity:

> "It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest…"

FERC thus has authority to set rates and allocate costs for interstate transmission service. FERC also has jurisdiction over regional transmission organizations (RTOs), which, in certain parts of the country, operate the transmission grids, conduct transmission planning, and run organized markets.[1]

B. Orders 679 and 679-A

On July 20, 2006, FERC issued Order 679, *Promoting Transmission Investment through Pricing Reform*. Order 679-A, issued on December 22, 2006, refined Order 679. The Orders established criteria and procedures by which transmission owners can receive "incentive-based" rate treatments for the transmission of electric energy. The Orders complied with Section 1241 of the Energy Policy Act of 2005 (EPAct 2005), which added a new section 219 to the Federal Power Act:

> "The Commission shall establish, by rule, incentive-based . . . rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by **ensuring reliability** and reducing the cost of delivered power by **reducing transmission congestion**." (emphasis added)

The legislation further stated that all incentive rates would remain "subject to the requirements of [FPA] Sections 205 and 206" and must be "just and reasonable and not unduly discriminatory or preferential."

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[1] For more information on electric industry background and FERC authority, please see NRRI's paper entitled *The Electric Industry at a Glance*, available online at http://nrri.org/pubs/electricity/electricity_at_a_glance.pdf, especially Section II.A.3.

Historically, utility obligations to serve and voluntary North American Electric Reliability Corporation (NERC) standards proved sufficient to ensure reliability. Regulators evaluated whether utilities' plans to do so were prudent (necessary and least-cost) and allowed just and reasonable returns on prudent investments. Congestion is a relatively new phenomenon in most parts of the country, a consequence of insufficient high-voltage transmission investment and increasing amounts of long-distance electricity sales. Implicit in EPAct 2005 is that utility obligations to serve and NERC standards have been insufficient to encourage certain types of transmission investments, necessitating additional incentives.

Order 679 authorizes providers of transmission service to seek a range of non-exclusive incentives, including **enhanced return on equity** (ROE), **inclusion of construction work in progress** (CWIP) in rate base, **hypothetical capital structures**, **accelerated depreciation**, **recovery of the costs of abandoned facilities**, and **deferred cost recovery**.[2] The Order also contains specific incentives for the formation of **transmission-only companies** ("Transcos") and **RTO participation**. Incentives are also available for projects using "**advanced technologies**." Section II discusses the process by which applicants acquire incentives.

Each applicant must demonstrate a "nexus" between the incentives requested and the investment being made. According to Order 679-A, FERC will grant incentives only if the entire incentive package results in a just and reasonable rate and if the final ROE (after all incentives are included) falls within the "zone of reasonableness" established in a discounted cash flow (DCF) analysis.[3] Order 679 also specified that an applicant does not need to pass a "but for" test or provide a cost-benefit analysis.[4]

FERC also sought to minimize applicants' regulatory burden of seeking the incentives. Accordingly, Order 679 allowed applicants to request single-issue ratemaking for transmission incentives rather than file general rate cases. Order 679-A stated that FERC would entertain requests for ROE determinations in **declaratory orders**.

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[2] Accelerated depreciation: A regulatory (not tax) treatment that allows the utility to recover asset capital costs more rapidly than through conventional straight-line depreciation, through which the utility recovers costs evenly over each asset's useful life.

Construction work in progress (CWIP): A regulatory treatment that allows utilities to earn a return on, but not of, investments before they are placed in service. Absent CWIP, utilities bear financing costs during the period prior to project operation and then recover them after projects commence operation.

Hypothetical capital structures: Capital structures not based on the actual balance of debt and equity. This regulatory treatment usually creates an equity-to-debt ratio higher than the actual ratio for purposes of calculating the rate of return.

[3] Discounted cash flow (DCF): A method for calculating the ROE by combining the estimated current yield, determined by utility's dividend price ratio, with a growth component.

[4] A "but for" test would require an applicant to demonstrate that, without the requested incentives, its project could not be developed.

II. Incentive Application Process

To receive transmission incentives, an applicant must demonstrate that (1) its project "either ensure[s] reliability or reduce[s] the cost of delivered power by reducing transmission congestion consistent with the requirements of Section 219," and (2) there is a "nexus" between the total package of requested incentives and the project's risks and challenges.[5] If the applicant satisfies both requirements, FERC will then authorize incentives, but will use its discretion to determine incentive levels. Additionally, the rate resulting from the combined incentives must be "just and reasonable." The following chart and the more detailed explanation in Section II.A describe this process.

[5] Order 679 at Par 76.

Process for Determining Incentive Eligibility and Size

I. **Section 219 requirements** – Applicant must demonstrate that the project ensures reliability or reduces congestion through A or B:

A. **Rebuttable presumption** is available to applicant if it is:

1. Approved by regional planning process, state commission, or state siting authority considering reliability and congestion relief benefits or*
2. Utilized FERC backstop siting authority

Applicants must survive attempts by other parties to rebut the rebuttable presumption.

*Even if approval has not yet been granted, applicants can receive the rebuttable presumption contingent upon approval by regional planning process or state siting authority.

B. **Independent Analysis –** Provide studies and analysis

II. "**Nexus test"** – Applicant must demonstrate that the package of requested incentives "address[es] the risks and challenges faced by the project" by showing either A or B:

A. Project is **not "routine"** because of a combination of:

1. Scope;
2. Effect; and
3. Challenges and risks

B. The project is "routine" but still has risks, challenges, and benefits meriting incentives

III. **FERC determines the appropriate incentive levels** (e.g., ROE incentive basis points and hypothetical capital structure ratio).

A. Reliability enhancement or congestion reduction

The roots of this requirement, which must be met for FERC to authorize incentives, are in Section 1241 of the Energy Policy Act of 2005, which adds **Section 219** to the Federal Power Act, as implemented by § 35.35(d) (1) of the Code of Federal Regulations. Order 679, proposed § 35.35(d) (1),

> "specifies that the Commission will authorize incentive-based rate treatments for investment by public utilities, including Transcos, in new transmission capacity that reduces the cost of delivered power by reducing congestion or promotes reliability, as demonstrated in an application to the Commission."

An applicant can satisfy its Section 219 requirements through either of two avenues. First, as described in Orders 679 and 679-A, an applicant can receive a "**rebuttable presumption**" that its project ensures reliability *or* reduces congestion through one of two paths[6]:

a. It explains how the regional planning process or state commission/siting authority approving the project considered reliability and congestion relief benefits; or

b. The project is sited by the Commission pursuant to its Section 216 backstop siting authority.[7]

In Order 679, FERC stated that it would grant the rebuttable presumption for a project that has not completed the regional planning process contingent upon approval through that process.[8]

We assume that the effect of a "rebuttable presumption," consistent with standard evidence law, is that if no one presents evidence sufficient to rebut the presumption, the applicant receives eligibility for incentives; but that if someone does present such evidence, the

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[6] The Commission, in *Startrans IO, LLC*, 122 FERC ¶ 61,306 (2008), interpreted Order 679 as finding that Transcos "satisfy section 219 of the FPA because this business model promotes increased investment in new transmission, which in turn reduces costs and increases competition." Thus, rather than a Transco receiving the rebuttable presumption of providing benefits, FERC has found that they *do* provide those benefits. Other Transcos have met their Section 219 requirements through independent evidence or the rebuttable presumption through state siting authorities or regional planning processes.

[7] Order 679-A at Par 47.

[8] Order No. 679 at footnote 39. FERC deviated from this approach in *Central Maine Power Co.*, 125 FERC ¶ 61,079 (2008). There FERC stated that if the applicant received a state or RTO approval, incentives would follow automatically; there would be no "rebuttable presumption."

applicant then bears the burden of going forward with additional evidence to support its application. The Commission has not specified what evidence constitutes sufficient rebuttal to shift the burden to the applicant.

Second, an applicant can satisfy its Section 219 requirements by submitting "**independent evidence**" describing reliability and congestion-relief benefits. The Commission has not, however, specified the necessary evidence:

> "Finally, except for the rebuttable presumptions addressed below, we will not at this time establish more detailed criteria an applicant must meet to be eligible for incentive-based rate treatments. Establishing criteria now would limit the flexibility of the Rule or improperly pre-judge which projects are acceptable for incentives. The Commission will, on a case-by-case basis, require each applicant to justify the incentives it requests."[9]

B. Nexus test

In Order 679, FERC found that "we do require applicants to show some nexus between the incentives being requested and the investment being made, i.e., to demonstrate that the incentives are **rationally related** to the investments being proposed" (emphasis added). According to Order 679-A, "In evaluating whether the applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project." FERC's application of the "nexus" test turns on whether the project is "routine," as explained next.

FERC found in Order 679 that "**routine**" investments "may not always… qualify for an incentive-based ROE." FERC later extended the routine standard to other incentives.[10] According to *Baltimore Gas and Electric Co.*, 120 FERC ¶ 61,084 (2007), "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive."

Paragraphs 52 and 53 of *BG&E*, which the Commission has cited in many subsequent transmission incentive orders, state:

> "First, to determine whether or not a project is not routine, the Commission will consider all relevant factors presented by the applicant. For example, an applicant may present evidence on: (i) the **scope** of the project (*e.g.*, dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (ii) the **effect of the project** (*e.g.*, improving reliability or reducing congestion costs); and (iii) the **challenges or risks** faced by the project (*e.g.*, siting, internal competition for financing with other projects, long lead

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[9] Order 679 at Par 43.

[10] *United Illuminating Co.*, 119 FERC ¶ 61,182 (2007).

> times, regulatory and political risks, specific financing challenges, other impediments).” (emphasis added)[11]

> “Second, applicants must provide detailed factual information in support of the factors they rely upon.”

Subsequent orders have also found that the use of **advanced technologies** or **the facilitation of renewable energy** generation make projects non-routine.

An applicant’s demonstration that its project is not routine is sufficient but not necessary to pass the nexus test. In certain circumstances, a routine project can still pass the nexus test. According to *BG&E*:

> “[I]f the Commission determines that a project is routine, an applicant is not necessarily foreclosed from incentives. The applicant may still be able to demonstrate that its project faces risks and challenges or provides sufficient benefits to warrant incentive rate treatment. However, because non-routine projects provide the most compelling case for incentives, we are not likely to grant incentives [to,] for example, discrete projects that replace existing equipment on a routine maintenance schedule.”

If an applicant passes the Section 219 requirements and nexus test, FERC then determines on a case-by-case basis the appropriate **incentive level**.

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[11] Of course, these are only examples of evidence that can help inform the Commission on the question of whether a project is routine. We are not proposing a new formulaic checklist that must be met by every applicant for every proposed incentive or project.

III. Application of Section 219 Requirements and the Nexus Test

A. Reliability and congestion relief benefit determination

As discussed in Section II.A, an applicant must demonstrate that its project ensures reliability or reduces congestion, satisfying its Section 219 requirements, in order to be eligible for incentives. It can do so through multiple mechanisms:

1. Rebuttable presumption

An applicant will receive the rebuttable presumption of providing reliability or congestion relief benefits if it can describe how its **state commission or siting authority** or **regional planning process** assessed reliability and congestion relief benefits in approving the project. Alternatively, a project will receive the rebuttable presumption if it is sited by the Commission pursuant to its Section 216 **backstop siting authority**, though FERC has not yet exercised this authority. FERC has not described the type of evidence needed to rebut the rebuttable presumption.

Most projects seeking incentives have sought the rebuttable presumption based on their regional planning processes. FERC has provided the rebuttable presumption to nearly all projects that underwent PJM's Regional Transmission Expansion Plan (RTEP) process or ISO-New England's regional planning process.[12] FERC also provided the rebuttable presumption to Southern California Edison, whose project was approved through the CAISO process.[13]

In *ITC Great Plains LLC*, 126 FERC ¶ 61,223 (2009), FERC determined that both the regional planning process and the state commission's review were insufficient to merit the rebuttable presumption. It found the Southwest Power Pool (SPP) Transmission Expansion Plan insufficient because it "does not reflect an SPP determination that they are needed to address either reliability or congestion." FERC also determined that the "nothing in the Kansas Commission certificate to construct orders indicates that the Kansas Commission evaluated the project to determine whether it ensures reliability or reduces the cost of redelivered power by reducing congestion."

The Commission also denied the rebuttable presumption in *PacifiCorp*, 125 FERC ¶ 61,076 (2008), because the Northern Tier Transmission Group conducted its formal planning through a "fast track" review for some PacifiCorp projects and did not review others. As with *ITC Great Plains*, after rejecting requests for the rebuttable presumption, FERC examined *PacifiCorp's* independent analysis for passing the Section 219 requirements.

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[12] In *BG&E*, FERC found that TO1 projects did not merit the rebuttable presumption because "unlike baseline project determinations, PJM makes no such determination that TOI upgrades mitigate congestion or ensures PJM's ability to serve load reliably…"

[13] *Southern California Edison*, 121 FERC ¶ 61,168 (2007)

2. Independent analysis

Several applicants have demonstrated that their projects provide reliability or congestion relief benefits through independent analyses. In evaluating such analyses, FERC has focused on evidence such as increased transfer capability, the findings of government entities, and improved access to renewable energy.

In *Green Power Express LP*, 127 FERC ¶ 61,031 (2009), in finding the Section 219 requirements met, FERC referenced the applicant's detailed studies and engineering affidavit demonstrating project benefits. Similarly, in *Nevada Hydro Co.*, 122 FERC ¶ 61,272 (2008), FERC noted that the applicant hired multiple firms to conduct extensive studies that included **power flow analyses** to demonstrate the increased transfer capability resulting from the project.

FERC also determined that PacifiCorp met its Section 219 requirements for most of its project segments, citing the applicant's reference to a **U.S. Department of Energy (DOE) report** and the 2004 Rocky Mountain Area Transmission Study. This study supported the utility's claim that the projects would reduce congestion and ensure reliability.

FERC noted in *Green Power* that the project would improve **access to renewable energy**. Similarly, in determining that the applicant had satisfied its Section 219 requirements, FERC stated in *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009) that the project would facilitate the interconnection of additional wind generation without causing reliability degradation.

In *BG&E*, FERC did not find Section 219 requirements met for 37 future projects, finding that the applicant "has not provided any showing that these projects ensure reliability or reduce the cost of congestion." Similarly, in *PacifiCorp*, FERC found that, for one of the eight segments, the applicant had not provided any reliability assessments demonstrating project benefits. This segment was also at a lower voltage (230 kV) than the other segments.

B. Application of the nexus test

Though FERC case law has developed for each incentive, this section will focus on how FERC has applied the nexus test for those incentives that it commonly grants, specifically the generic ROE, CWIP in rate base, hypothetical capital structures, advanced technologies, RTO participation, and Transco formation incentives. Generalizations about the accelerated depreciation and deferred cost recovery incentives are difficult, given their rarity. FERC has almost always granted requests for the abandoned plant incentive; its application does not appear to have evolved since Order 679.

1. Return on equity

a. ROE incentive evaluation criteria

FERC has usually found the nexus test for the generic ROE incentive met where an applicant has demonstrated that a project is not routine through detailed, particularly quantified, evidence. In approving ROE incentives, FERC has often cited applicants' arguments regarding projects' "scope" relative to their cash flow, rate base, and/or average transmission expenditures.

Scope descriptions, "*e.g.*, dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region," often demonstrate projects' potential financial effects and thus risks for their owners.[14] Some applicants described how incentives would improve their **access to capital** by demonstrating **financial risk or insecurity**. The Commission has also found persuasive descriptions of poor or potentially poor **credit ratings**.[15]

The Commission has also responded favorably to descriptions of project **regulatory risks**. For instance, in *Central Maine Power Co.*, 125 FERC ¶ 61,079 (2008), FERC referenced siting difficulties due to the project's potential to cross 80 municipalities and multiple regulatory approvals as part of the reason it granted 125 of the requested 150 basis points of generic ROE incentives.[16] Additionally, FERC considered the "unique regulatory risk that Maine will withdraw from ISO-NE." It also described the project's crossing of sensitive environmental areas as increasing "environmental risks."

An applicant can also demonstrate its project's non-routine nature by describing the use of **advanced technologies**. In *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 (2008), FERC found:

> "To the extent that the nature of this project requires a more significant application of this technique than is commonly seen, the associated challenges can be incorporated into the overall nexus analysis, but the technique does not, in and of itself, appear to justify a separate advanced technology adder."

In *Potomac Electric Power Co.*, 125 FERC ¶ 61,130, the Commission cited the use of advanced technologies in finding that "PHI's use of advanced technology warrants the 150-basis-point adder."

Although the Commission, in *BG&E*, encouraged applicants to demonstrate that their projects are not routine by describing the "effect of the project (*e.g.*, improving reliability or reducing congestion costs)," few have done so in more than general terms. One exception is *PacifiCorp*, where the utility described the reliability and congestion relief benefits of increased transfer capability and the environmental benefits of **reaching remote renewable energy** resources. FERC approved 200 of PacifiCorp's requested 250 basis points of generic ROE incentives, with Chairman Wellinghoff's concurrence citing accessing remote renewable resources as a basis for finding that the project was not routine.

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[14] See *BG&E*.

[15] *Westar Energy, Inc.*, 122 FERC ¶ 61,268 (2008) at Par 47

[16] Basis point: As applied to the return on equity and rate of return, each basis point is one one-hundredth of a percent.

b. When does FERC deny ROE incentives?

FERC has denied ROE incentives for a project receiving the rebuttable presumption of satisfying Section 219 requirements for three reasons: (1) the project failed the nexus test by not demonstrating that it is not routine, (2) the project was constructed in response to a FERC mandate, or (3) the project was already complete. It is useful to examine the rationales for denying incentives to evaluate what type of information and analysis applicants must provide.

Although an applicant can demonstrate that its project is not routine based on "scope," "benefits," and "risks or challenges," as described in Section II.B, FERC requires some depth of analysis. Accordingly, for some of the projects in *BG&E*, FERC found that the application lacked "fact-specific reasons why each project or group of projects qualifies for an ROE incentive." Further, the utility "did not demonstrate that the future projects address **demonstrable risks and challenges** that are not routine." Similarly, according to *Commonwealth Edison Co.*, 125 FERC ¶ 61,250 (2008), the applicant failed to show how its projects faced risks or challenges that warranted an incentive ROE under the nexus requirement. Specifically, it had not "presented evidence regarding the scope or effect of the projects, and focus[ed] primarily on financing challenges; there [was] **no evidence of technical or siting challenges, long lead times, or regulatory or political risks facing the projects**" (emphasis added).

In *NSTAR Electric Co*., 125 FERC ¶ 61,313 (2008), FERC denied incentives for some projects in part because NSTAR did not present "sufficient evidence regarding the **financial impact or burden** that NSTAR faces in financing these two projects."

In *NSTAR*, FERC also denied ROE incentives in part because "both of these projects are being developed and constructed entirely by NSTAR, are located in Massachusetts, and thus have **limited regional reliability impacts**." FERC's *NSTAR* ruling constitutes a policy reversal because, according to Order 679, "[o]ur policies also must encourage all other needed transmission investments, *whether they are regional or local*, designed to improve reliability or to lower the delivered cost of power" (emphasis added).

FERC denied requested incentives for one of the projects in *Westar Energy Inc.*, 122 FERC ¶ 61,268 (2008) for failure to pass the nexus test because the project responded to a **FERC-imposed obligation**. FERC had previously directed Westar to increase transfer capability (which would require building a transmission line) as part of the market power mitigation requirements from another docket. FERC found that "projects that an entity is required to build may not always qualify for certain incentives because there is an obligation to construct the line and a high assurance of recovery of the related costs." FERC's treatment of obligations to build is based on the obligation's source. FERC found in *Northeast Utilities* that the utility's obligation to build due to ISO-New England's Regional System Plan does not preclude it from incentives:

> "First, Public Parties' reference to *Westar* is not comparable, since the findings made in that case were based upon the utility's obligation to comply with a Commission order that made construction of the facilities an express condition of another Commission approval, which is not the case here. Further, Order No. 679-

A explicitly states that an obligation to build *does not preclude* eligibility for incentives, although such obligations 'may have a bearing on our nexus evaluation of individual applications.'"

Finally, in *Westar,* FERC denied ROE and accelerated depreciation incentives for a project, finding that incentives would not encourage additional investment because the project was **already completed**. FERC stated that "[a] project's planning and completion dates are germane when determining whether incentives may be appropriate" and that "Westar has not shown that the ROE incentive or the accelerated-depreciation incentive it requests could encourage investment… because the project was completed…"

c. ROE incentive level trends and observations

This section describes trends in the size of the generic ROE incentive in different regions and circumstances. Orders 679 and 679-A described how the Commission determines ROE incentives on a case-by-case basis. Nonetheless, certain patterns have emerged. As shown in Appendix A, in cases where the Commission has explicitly stated the generic ROE incentives, the incentives have usually ranged from 100 to 150 basis points. The Commission has also shown relative consistency at a regional level, as discussed below.

The Commission has provided a 100-basis-point generic ROE incentive adder to three of the four **ISO-New England** members requesting generic ROE incentives. This near uniformity stems from Opinion No. 489, in which FERC accepted "the proposed ROE incentive [100 basis points] as applicable to *all* projects identified as necessary by ISO New England in its regional planning process." Although the Order stipulates that the projects must come online prior to December 31, 2008 to receive this incentive, FERC has provided waivers to that date requirement in *NSTAR* and in *Northeast Utilities Service Co*., 124 FERC ¶ 61,044 (2008). In *Central Maine*, FERC granted 125 instead of 100 basis points, finding that the final ROE was still within the range established in Order 489. Based on these waivers and the *Central Maine* ROE level exception, it is uncertain whether future ROE incentives in New England will diverge from 100 basis points.

Where the Commission has found the nexus test met, the generic ROE incentives approved in the eight cases with **PJM** members have ranged from 100 to 150 basis points. In six cases, some or all of the applicants' projects received 150 basis points. This relative consistency could stem from several incentive applications relating to the Mid-Atlantic Power Pathway, making certain risks and challenges common.

FERC has been more likely to reduce the approved generic ROE incentive from that requested (typically by 25 basis points) for projects that also receive **CWIP** in rate base than for projects that do not. For example, in *Central Maine*, FERC found that "Central Maine's overall risk is reduced by our decision, discussed below, to authorize the requested CWIP in rate base and abandonment incentives. Accordingly… we authorize a 125 basis point ROE incentive adder for the Project [Central Maine requested 150 basis points]." FERC found in *Tallgrass* that it would not create a generic rule for the reduction of the ROE incentive for projects receiving risk-mitigating incentives like CWIP because "companies, anticipating such a reduction, would simply request a higher return on equity incentive to compensate for the reduction."

2. CWIP in rate base

When evaluating whether CWIP in rate base requests pass the nexus test, FERC focuses on projects' **financial risks and consequences**, such as credit rating reductions. Accordingly, in *Startrans*, FERC stated that it allows 100 percent CWIP in rate base only in cases "where the utility demonstrated that, due to the size, scope, and/or construction time of the projects, there was an increased risk to the company's credit rating."

In *Startrans* FERC allowed other incentives, but not CWIP in rate base. FERC denied the CWIP incentive due to the project's **short lead time** and the applicant's failure to demonstrate that the project would cause cash flow difficulties or adversely affect the utility's credit rating.

In approving the requested CWIP incentive in *Southern California Edison*, FERC found that, "[b]y permitting SCE to recover CWIP, the Commission is **mitigating this rate shock** to consumers [from the $2.5 billion increase in rate base]."

FERC described in *New York Regional Interconnect Inc.*, 124 FERC ¶ 61,259 (*NYRI*) that **Transcos** might not be eligible for CWIP. It concluded that, "[a]s an independent transmission developer, NYRI does not have an identifiable base of customers to whom CWIP and abandoned plant costs could be assigned, and, therefore, NYRI did not have the option to request such incentives."

3. Advanced technology

EPAct 2005 mandated that FERC provide incentives for the use of advanced transmission technologies, which are "technologies that increase the capacity, efficiency, or reliability of an existing or new transmission facility."[17] FERC has denied requests for the advanced technologies incentive more often than other incentives. In the few instances when FERC has

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[17] According to Section 1223 of the Energy Policy Act of 2005, advanced technologies include "(1) high-temperature lines (including superconducting cables); (2) underground cables; (3) advanced conductor technology (including advanced composite conductors, high-temperature low-sag conductors, and fiber optic temperature sensing conductors); (4) high-capacity ceramic electric wire, connectors, and insulators; (5) optimized transmission line configurations (including multiple phased transmission lines); (6) modular equipment; (7) wireless power transmission; (8) ultra-high voltage lines; (9) high-voltage DC technology; (10) flexible AC transmission systems; 11) energy storage devices (including pumped hydro, compressed air, superconducting magnetic energy storage, flywheels, and batteries); (12) controllable load; (13) distributed generation (including PV, fuel cells, and microturbines); (14) enhanced power device monitoring; (15) direct system state sensors; (16) fiber optic technologies; (17) power electronics and related software (including real time monitoring and analytical software); (18) mobile transformers and mobile substations; and (19) **any other technologies the Commission considers appropriate**" (emphasis added).

granted and explicitly stated the size of this incentive, it has provided a **50-basis-point** ROE adder.[18] FERC has not specified why 50 basis points is this incentive's appropriate size.

By denying or accepting requests for the advanced technologies incentive, FERC has illustrated the types of technologies and applications that do and do not warrant this incentive. In *NSTAR*, FERC found that it would not provide the incentive for the use of Static VAR Compensator technology because "NSTAR had not indentified either any **unusual characteristics of or risks, challenges, or benefits** associated with that technology that warrant incentive treatment" (emphasis added). Additionally, in *Commonwealth Edison* FERC found that "we are required under Section 1223 of EPAct 2005 to 'encourage, as appropriate' the deployment of [technologies listed in EPAct 2005], and that use of such technologies does not automatically warrant the granting of incentives."

FERC also considers the **magnitude** of a technology's application. In *NSTAR*, it denied the incentive for the use of XLPE underground cable, for which it had provided the incentive in *United Illuminating* and *Northeast Utilities*, because the cable would be used for a short distance, leading to manageable engineering and installation challenges.

In *New York Regional Interconnect*, FERC granted the incentive, concluding:

> "[T]he underground portion of the Project may help facilitate acceptance of the Project in highly concentrated urban and suburban portions of the route… In sum, the advanced technologies proposed will improve capacity, efficiency and reliability for the Project."

FERC applied the advanced technology incentive to the *entire NYRI* project because "[b]oth the HVDC and fiber optics technologies will span the entire Project, and the SVCs will increase overall reliability." By contrast, in *United Illumining Co.*, 119 FERC ¶ 61,182 (2007) and *Northeast Utilities*, FERC provided the advanced technologies adder, but only for those parts of the project utilizing advanced technologies, rather than for the entire project.

4. RTO participation

FERC provides the RTO participation incentive independently of an applicant's showing of the nexus between the project's risks and challenges and the incentive. Rather, it presumes that all RTO participants merit this incentive. Order 679 stated that FERC provides this incentive "in recognition of the benefits such organizations bring to customers, as outlined in detail in Order No. 2000." FERC found in *Pennsylvania Power and Light Corp.,* 123 FERC ¶ 61,068 (2008):

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[18] *United Illuminating* and *Northeast Utilities* received 50 basis points. The advanced technology adder was not differentiated from the total ROE incentive in *New York Regional Interconnect*.

> "The consumer benefits, including reliable grid operation, provided by such organizations are well documented and consistent with the purpose of Section 219. The best way to ensure these benefits is to provide member utilities of an RTO with incentives for joining and remaining a member. As explained in Order No. 679-A, the decision to provide incentives for participation in an RTO is a policy one, aimed at promoting particular **policy objectives**, unrelated to any particular project." (emphasis added)

FERC has consistently approved **50-basis-point** ROE adders for RTO participation.[19] This uniformity contradicts FERC's statement in Order 679 that "we are not persuaded that we should create a generic adder for such membership, but instead will consider the appropriate ROE incentive when public utilities request this incentive." FERC has not subsequently explained why 50 basis points is the appropriate RTO participation incentive size for all applicants.

Both existing and new RTO members receive this incentive. In *Southern California*, FERC found, "eligibility for this incentive has been modified to permit adders for not only *existing* membership in a transmission organization, but also to encourage *continued* membership, as specified in Order No. 679." FERC has granted this incentive regardless of whether or not an applicant's state requires utility RTO participation.

FERC, in *ITC Great Plains*, provided the RTO participation adder, contingent on the company joining an RTO—the Southwest Power Pool.

5. Transco formation

Like the RTO participation incentive, FERC provides the Transco formation incentive independently of the applicant's showing of the nexus between the risks and challenges of the project and the requested incentives. Rather, FERC presumes that all Transcos merit this incentive because "the singular focus of transmission-only companies, the elimination of competition for capital between generation and transmission investments, and the access to capital markets all support the value of the Transco business model for getting new transmission built."[20]

FERC consistently allows a **100-basis-point** ROE adder for Transco formation, which it provided in *New York Regional Interconnect*, *ITC Great Plains*, and *Green Power*. FERC has not provided a rationale for why 100 basis points is the appropriate ROE adder for addressing the specific risks and challenges of Transcos.

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[19] Examples include: *Duquesne Light Co.*, 118 FERC ¶ 61,087 (2007); *Commonwealth Edison Co.*, 119 FERC ¶ 61,238 (2007); *Central Maine Power Co.*, 125 FERC ¶ 61,079 (2008); *PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 (2008), and *Baltimore Gas and Electric Co.,* 120 FERC ¶ 61,084 (2007) (2007) (*BG&E Order*).

[20] *ITC Great Plains*

In *NYRI*, FERC granted the incentive prior to Transco formation. It granted the incentive contingent upon "NYRI's ROE being within the zone of reasonable returns (as established in NYRI's Section 205 filing), the Project receiving state siting approval, and NYRI **forming the Transco business entity as proposed**" (emphasis added).

In S*tartrans,* FERC provided the Transco formation ROE incentive, despite the Transco being formed by acquisition and not by the construction of new transmission facilities. This application of the Transco formation incentive indicates that the incentive applies to the existing assets of Transcos and not just new projects.

6. Hypothetical capital structures

FERC stated in Order 679 that "in certain contexts, [the hypothetical capital structure incentive] is appropriate for consideration under Section 219 because it has been demonstrated to foster the development of transmission investment." FERC has granted hypothetical capital structures only to startups, which lack historic capital structures. In five of the six cases where FERC has approved hypothetical capital structures, the capital structure applied for and granted was fifty percent debt and fifty percent equity.[22] In *Tallgrass*, FERC supported the 50/50 capital structure because "[w]e direct the applicants to adopt a capital structure based upon actual financing when the projects are complete, as the applicants state that they will do." FERC did not cite this rationale in other cases where it allowed 50/50 hypothetical capital structures.

It is uncertain whether FERC intends for 50/50 hypothetical capital structures to be the standard, as it approved a sixty-percent-equity, forty-percent-debt capital structure in *Green Power*. FERC in part justified the *Green Power* hypothetical capital structure by stating that "this hypothetical structure is the same as Green Power's target capital structure, which it will employ at the time that any of Green Power's assets are placed in service."

Even where applicants have requested hypothetical capital structures for longer durations, FERC has restricted their use to projects' **construction periods**. FERC reasoned that capital structures vary markedly during the construction phase due to periodic infusions of debt and equity capital. Accordingly, in *Tallgrass* the Commission found that "without use of this hypothetical capital structure, Tallgrass and Prairie Wind would need to track the constantly changing capital structure. This can be complicated and result in unpredictable cash flows."

[22] *Pioneer*, *Potomac-Appalachian Transmission Highline*, *LLC,* 122 FERC ¶ 61,188 (2008), *Tallgrass Transmission*, and *Nevada Hydro* each received fifty percent debt and fifty percent equity. In *Trans-Allegheny Interstate Line Co*., 119 FERC ¶ 61,219, FERC granted a 50/50 hypothetical capital structure, though the applicant did not apply for it "as a formal incentive."

IV. Recommendations

FERC's transmission incentive policy lacks the necessary rigor to demonstrate that the resulting rates are just and reasonable. The following recommendations aim to correct this deficiency. Subsections A and B address the lack of cost-benefit analysis and the appropriateness of the RTO incentive, while Subsections C, D, and E suggest modifications to reduce the "black box" element of FERC's provision of incentives.

A. How can FERC improve the nexus test?

1. Critique: FERC does not consider project cost-benefit ratios

As discussed in Section II.B, the "nexus test" requires applicants to show that requested incentives "are rationally related to the investments being proposed" and that they "address the risks and challenges faced by the project." The terms "rationally related" and "address" do not specify *how* incentives facilitate projects or correspond to their benefits. In most cases, an applicant must demonstrate that its project is not "routine" to pass the nexus test. According to *BG&E*, an applicant must provide evidence of a project's "scope," effects," and "challenges and risks" to show that it is not routine. In *BG&E* and subsequent orders, FERC described some of the types of evidence that do and do not demonstrate that a project is not routine. FERC has not, however, articulated how much of each type of evidence is necessary. Further, neither the nexus test nor the routine standard addresses whether a project's benefits must outweigh the customer costs of requested incentives.

EPAct 2005 mandated that FERC provide transmission incentives to projects "ensuring reliability and reducing the cost of delivered power by reducing transmission congestion." This legislative mandate does not relieve FERC of the responsibility to ensure that projects are prudent and least-cost. Order 679, however, states that applicants do not need to provide a cost-benefit analysis or pass a "but for" test. FERC has also not described any internal mechanism for determining whether incentives are needed or cost-effective. To provide incentives without examining their need or their cost-benefit ratios undermines just and reasonable ratemaking, which EPAct 2005 requires.[23]

2. Recommendation: Impose a cost-benefit requirement

FERC should require as much quantification as possible of project benefits. Regional planning processes, such as PJM's Regional Transmission Expansion Plan (RTEP), quantify long-run reliability benefits in order to identify projects that best serve the region and allocate their costs.[24] The RTEP process also identifies to what degree various "economic upgrades"

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[23] Section 1241 of the Energy Policy Act of 2005, which revised Section 219 of the Federal Power Act.

[24] Currently, such allocations are only conducted for projects below 500 kV. The costs of larger projects are spread throughout the PJM region, although the 7th Circuit Court of

would relieve congestion. Additionally, RTOs with financial transmission rights already have the means by which to value congestion.[25] It is thus possible to compare, at least for the short-term, a project's congestion cost savings with the status quo.

It is harder to estimate, much less value, the long-run benefits of assuring reliability or reducing congestion because load and power flows change over time. An optimal "but for" analysis is difficult, as there is often some subjectivity regarding what ROE a project *needs* to attract capital. These challenges do not mean, though, that FERC should utilize opaque evaluation criteria rather than some form of cost-benefit analysis.

A basic cost-benefit analysis could rule out providing incentives for projects whose reliability and congestion relief benefits *could not* match incentives' ratepayer costs. In order to pass the nexus test, applicants should have to demonstrate that the reliability and congestion relief benefits *could* equal or exceed the incentive costs.

B. How can FERC improve the RTO participation incentive?

1. Critique: The RTO incentive has not been shown to increase RTO participation

FERC has consistently provided 50-basis-point ROE incentives for RTO participation, based on the benefits they provide. FERC has provided no evidence that the incentive has led to higher rates of RTO participation or prevented withdrawals. Only one major investor-owned utility, MidAmerican, in recent years has joined an RTO.[26] MidAmerican cited increased access to organized markets as its motivation for joining MISO, rather than FERC regulatory treatments.[27] If the RTO participation incentive does not cause utilities to join or stay in RTOs, it is a *de facto* regional incentive that excludes projects in the Southeast and the West outside of California.

FERC has also provided this incentive regardless of state regulatory or legislative mandates for RTO participation. Thus, certain utilities receive higher ROEs without any potential for the incentive to affect their RTO status.

Appeals rejected this methodology in its August 6, 2009 decision in *Illinois Commerce Commission v. FERC*. http://www.pjm.org/planning/~/media/documents/manuals/m14b.ashx.

[25] Financial transmission rights (FTRs): Financial instruments auctioned in certain RTOs. FTRs enable holders to hedge against locational electricity price differences caused by transmission constraints in the day-ahead energy market.

[26] In 2008, the Nebraska Public Power District, Lincoln Electric Systems, and Omaha Public Power District elected to join the Southwest Power Pool. Municipal utilities and rural electric cooperatives do not usually receive a return on equity, making them indifferent to ROE incentives.

[27] See the press release of MidAmerican Energy, which joined MISO. http://www.reuters.com/article/pressRelease/idUS191866+27-Apr-2009+PRN20090427.

2. Recommendation: Replace the RTO participation incentive with an incentive for projects in critical regions

An alternative way to promote Section 219 goals would be to provide ROE incentives for projects in regions in severe need of transmission investments. FERC could, for instance, provide ROE adders to projects located in National Interest Electric Transmission Corridors. FERC could also define eligible regions based on criteria such as the level of congestion or the frequency of load-shedding events. This practice would avoid the granting of the RTO incentive to projects where the utility would be a member of the RTO regardless of the incentive. FERC would need to justify whatever incentive level it provides (either uniform or determined on a case-by-case basis) through analyses of the needs and benefits of projects in these regions.

FERC could also define regions, similar to the Competitive Renewable Energy Zones in Texas, in which it seeks additional transmission infrastructure to access renewable resources. The Commission could allow projects in such regions to apply for ROE incentives. FERC would need to cite authority other than EPAct 2005, which authorizes incentives only for projects that ensure reliability or reduce congestion.

C. How should FERC determine generic ROE incentive levels?

1. Critique: Generic ROE incentive level determinations are unpredictable and unsupported

FERC evaluates requests for generic ROE incentives on a case-by-case basis. It sometimes provides the requested incentive level and sometimes approves an incentive lower than that requested. FERC's orders provide narrative explanations of why applicants should or should not receive incentives and the reasons for any reduction from the requested levels. The orders, however, do not explain why approved generic ROE incentives are the appropriate size. FERC has not divulged what, if any, internal quantitative or qualitative analysis it utilizes to determine the incentive level. FERC's lack of demonstrated analysis creates a lack of transparency and the appearance of a lack of precision.

Additionally, it is not reasonable to determine generic ROE incentive levels independently of determining the base ROE (the ROE not including incentives). The same risks and challenges that could merit ROE incentives often determine DCF proxy groups and lead to base ROEs in the upper end of the zone of reasonableness. Consequently, applicants could receive compensation for the same risks and challenges multiple times.

2. Recommendation: Reveal or create an analytical methodology for determining ROE incentive levels

FERC should either explain its methodology to determine generic ROE incentive levels or develop and divulge a transparent analysis by which to do so. Doing either would increase the predictability of FERC's incentives, which would benefit both applicants and intervenors. If not in place already, a rigorous methodology for determining ROE incentive levels would better promote just and reasonable rates. Generic ROE incentive level determinations should also consider expected project benefits, such that the incentive produces favorable cost-benefit ratios.

Order 679-A stated that the Commission could determine the total ROEs in declaratory orders if the applicant provides additional evidence to inform a DCF analysis, though it has done so only in some cases.[28] In certain orders where FERC describes the final ROE, it had previously determined the base ROE.[29] FERC should provide incentives *only* in conjunction with determining the overall ROE level. Doing so would prevent incorporating a project's risks and challenges into both the ROE incentive and base ROE determinations. As discussed in Section IV.D, the final ROE (base ROE plus incentives) should also consider incentives that reduce risk.

D. How should ROE determinations consider risk-reducing incentives?

1. Critique: FERC does not appear to account systematically for risk-reducing incentives

According to Order 679-A, in determining whether projects pass the nexus test, FERC will examine "the interrelationship between any incentives." FERC has not explained how it examines these interrelationships. Specifically, FERC has not defined how much risk-reducing incentives such as CWIP in rate base, abandoned plant recovery, and accelerated depreciation reduce the appropriate final ROE, inclusive of incentives. Consequently, final incentive levels are unpredictable. In *Tallgrass*, FERC declined to provide predetermined reductions of generic ROE incentives for utilities receiving risk-reducing incentives:

> "If the Commission were to have a generic rule that requires a reduction in the return on equity incentive whenever other incentives that mitigate risk, such as construction work in progress, are granted, then companies, anticipating such a reduction, would simply request a higher return on equity incentive to compensate for the reduction."

This statement implies that the Commission does not and could not independently determine the appropriate level of generic ROE incentives. Instead, FERC apparently bases its ROE decisions on applicants' requests. This reactive stance conflicts with FERC's mandate to provide rates that are just and reasonable.

Order 679-A states that the Commission will examine the total package of requested incentives on a case-by-case basis and use its judgment to determine the appropriate incentive levels. Thus, the requested generic ROE incentive level is irrelevant. For otherwise identical projects, FERC should not grant generic ROE incentives any differently for an applicant requesting 300 basis points than for an applicant requesting 100 basis points. Rather, it should independently determine the appropriate ROE based on the facts presented.

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[28] Order 679-A at Par 70. Examples of FERC establishing both the base and final ROE in the declaratory order include *Green Power* and *Great Plains*.

[29] *Virginia Electric Power Co.*, 124 FERC ¶ 61,207 (2008) and *Westar.*

2. Recommendation: Create standard ROE reductions for risk-reducing incentives

The Commission should state that it will reduce projects' final ROE (base ROE plus generic ROE incentives) by a specific amount in conjunction with each risk-reducing incentive. For instance, FERC could state that it will reduce projects' final ROEs by 50 basis points if they receive CWIP in rate base. FERC should base these reductions on an investigation of how much various incentives reduce utilities' costs of capital. This practice would increase the transmission incentive policy's transparency and predictability. The practice would also demonstrate that FERC considers the risk-reducing characteristics of non-ROE incentives and incentive interrelationships, promoting just and reasonable rates.

E. How should FERC determine the ROE incentives levels for RTO participation, Transco formation, and advanced technologies?

The following analysis applies to the RTO participation incentive if FERC continues to provide this incentive.

1. Critique: FERC has not justified RTO participation, Transco formation, and advanced technologies incentive levels

Order 679 stated that the Commission would not authorize standardized incentive levels for the RTO participation and advanced technologies incentives. FERC has nonetheless provided uniform incentive levels for RTO participation, Transco formation, and advanced technologies of 50, 100, and 50 ROE basis points respectively. It has not described why these levels correspond to the incentives' benefits or projects' risks.

FERC has also not explained why each incentive level should be uniform. FERC provides the same ROE incentive level for participation in all RTOs, despite differences in RTO traits and thus consumer benefits. Similarly, it has not described why all Transcos have received a 100-basis-point incentive, despite differences in their levels of independence and their transmission development plans. Finally, FERC has not explained why all applicants eligible for the advanced technologies incentive should receive 50-basis-point incentives. A uniform incentive level is not appropriate if advanced technology risks and benefits vary.

2. Recommendation: Substantiate incentive levels

If FERC continues to grant a uniform ROE incentive for RTO participation, it should explain why a 50-basis-point incentive corresponds to the observed benefits of RTO participation. Alternatively, FERC could provide varying incentive levels for participation in different RTOs based on variations in RTO market features, regional planning processes, and grid operation. FERC would need to provide a qualitative and quantitative justification for any such variations.

FERC should also explain why the 100-basis-point incentive for Transco formation matches the benefits that Transcos provide customers. Alternatively, FERC could provide and justify varying incentive levels, depending on each Transco's level of independence from other utilities and its transmission development plans. Similarly, FERC should justify the current 50-

basis-point incentive for advanced technologies. It should also consider providing different incentive levels to various advanced technologies, based on their different levels of risks and benefits.

F. Conclusion

The above recommendations enhance the cost-effectiveness and predictability of transmission incentives, promoting just and reasonable rates. The challenge remains to devise ways to conduct cost-benefit analyses and other calculations to determine whether projects merit various incentives and what the incentive levels should be.

Appendix A

FERC has provided generic ROE incentives in the following cases:

Utility	Decision Year	Requested/Granted Basis Point addition to ROE
Bangor Hydro	2006	100/100
Duquesne	2007	150/150
Baltimore Gas and Electric	2007	100/100 for some projects
Commonwealth Edison	2008	150/150 for some projects
Southern California Edison	2008	150/125 and 100/75 (multiple projects)
Westar	2008	100/100 (accepted requested ROE of 12.3% which include 100-basis-point incentive adder)
Pennsylvania Power and Light	2008	150/125
Virginia Electric Power Company	2008	150/150 and 125/125 (multiple projects)
New York Regional Interconnect	2008	250/125 (combined generic and advanced technologies)
PacifiCorp	2008	250/200 for some projects
Potomac Electric Power Company	2008	150/150

Northeast Utilities	2008	100/100
Central Maine	2008	150/125
NSTAR	2008	100/100 for certain projects
Pacific Gas and Electric	2008	200/200
Public Service Enterprise Group	2009	150/150
Green Power Express	2009	10/10
Tallgrass Transmission	2009	150/150
Pioneer Transmission	2009	150/150
Baltimore Gas and Electric	2009	150/150

Note: In *Startrans IO, LLC*, 122 FERC ¶ 61,306 (2008) the Commission did not approve a specific ROE incentive adder but determined the final ROE should be at the upper end of the zone or reasonableness; it approved a particular ROEs without specifying generic ROE adders sizes. FERC also deferred determination of ROE incentive levels in *San Diego Gas and Electric Co.*, 118 FERC ¶ 61, 073 (2007), and *American Electric Power Co.*, 116 FERC ¶ 61,059 (2006), and *Pacific Gas and Electric Co.*, 123 FERC ¶ 61,067 (2008). Applicants did not request generic ROE incentives in *United Illumining Co.*, 119 FERC ¶ 61,182 (2007), *Xcel Energy Services Inc.*, 121 FERC ¶ 61,284 (2007), *ITC Great Plains LLC*, 126 FERC ¶ 61,223 (2009), or *Nevada Hydro Co.*, 122 FERC ¶ 61,272 (2008). In *Trans-Allegheny Interstate Line Co*., 119 FERC ¶ 61,219 (2007) FERC granted an ROE at the top of the zone of reasonableness but did not define the ROE. In *Bangor Hydro Electric Co.*, 122 FERC ¶ 61,265 (2008), the Commission granted incentives based on Order 489 and not Orders 679 and 679-A.

Appendix B: Glossary

Accelerated depreciation: A regulatory (not tax) treatment that allows the utility to recover asset capital costs more rapidly than through conventional straight-line depreciation, through which the utility recovers costs evenly over each asset's useful life.

Basis point: As applied to the return on equity and rate of return, each basis point is one one-hundredth of a percent.

Construction work in progress (CWIP): A regulatory treatment that allows utilities to earn a return on, but not of, investments before they are placed in service. Absent CWIP, utilities bear financing costs during the period prior to project operation and then recover them after projects commence operation.

Discounted cash flow (DCF): A method for calculating the ROE by combining the estimated current yield, determined by utility's dividend price ratio, with a growth component.

Financial transmission rights (FTRs): Financial instruments auctioned in certain RTOs. FTRs enable holders to hedge against locational electricity price differences caused by transmission constraints in the day-ahead energy market.

Hypothetical capital structures: Capital structures not based on the actual balance of debt and equity. This regulatory treatment usually creates an equity-to-debt ratio higher than the actual ratio for purposes of calculating the rate of return.

Transcos: Companies that own transmission but not generation or distribution assets and have been approved by FERC to sell transmission for wholesale power or unbundled retail power.