UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Regarding the Commission's Electric Transmission Incentives Policy	Docket No. PL19-3-000

COMMENTS OF SOUTHERN NEW ENGLAND STATE AGENCIES

Southern New England State Agencies (State Agencies)[1] appreciate this opportunity to comment on the Federal Energy Regulatory Commission's March 21, 2019 Notice of Inquiry (NOI)[2] concerning its transmission incentives policy.

I. INTRODUCTION AND OVERVIEW OF POSITIONS

State Agencies bring a balanced perspective to the questions posed by the NOI because we represent consumers who both depend on the transmission grid and pay its costs. We support measures that make more efficient use of existing transmission facilities, and favor building new facilities where necessary and cost effective to improve the transmission grid's reliability, efficiency, and ability to integrate clean-energy resources. At the same time, however, we deem it essential to achieve these ends as efficiently and cost-effectively as possible.

Our balanced approach is neither new nor unique. Indeed, it echoes the perspective underlying Federal Power Act (FPA) section 219. There, Congress directed the Commission to establish "incentive-based (including performance-based)"

---

[1] State Agencies include: the Connecticut Public Utilities Regulatory Authority, the Connecticut Department of Energy and Environmental Protection, the Connecticut Office of Consumer Counsel, the Connecticut Office of the Attorney General, and the Massachusetts Office of the Attorney General.

[2] Inquiry Regarding the Commission's Electric Transmission Incentives Policy, 166 FERC ¶ 61,208 (2019).

transmission rate treatments that (among other things) "promote reliable and economically efficient transmission and generation of electricity . . . ;" "provide a return on equity that attracts new investment in transmission facilities . . . ;" and "encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve [their] operation." 16 U.S.C. §§ 824s(a), (b). But Congress made those directives "subject to" the FPA's over-arching requirement that "all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential." 16 U.S.C. § 824s(d).

That is a meaningful limitation. As the Commission and courts have recognized, the FPA is first and foremost a consumer protection statute. *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760, 781 (2016); *Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish, Cty., Wash.*, 554 U.S. 527, 551 (2008); *Mun. Light Boards of Reading & Wakefield, Mass. v. FPC*, 450 F.2d 1341, 1348 (D.C. Cir. 1971). It affords consumers a "complete, permanent, and effective bond of protection from excessive rates and charges." *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388 (1959). That injunction should apply with special force to regulation of those segments of the industry not yet subject to effective competition.

As detailed below, we believe that the Commission's 2012 Policy Statement strikes the right balance.[3] It correctly emphasizes incentives that directly address—and help to reduce—the risks that impede transmission investment. *See* 2012 Policy Statement P 16. At the same time, it correctly regards other incentives—primarily, return

---

[3] *Promoting Transmission Investment Through Pricing Reform*, 141 FERC ¶ 61,129 (2012) (2012 Policy Statement).

on equity (ROE) adders—as ripe for consideration only in more limited circumstances. The 2012 Policy Statement deems ROE adders appropriate only when a transmission owner has taken steps to reduce project risk, through risk-reducing incentives and otherwise, but still faces levels of project risk that are not compensated by its base ROE. *See* 2012 Policy Statement PP 20, 22. Consideration of ROE adders only in these limited circumstances is appropriate, as such incentives operate by making transmission projects more profitable for investors—which means they are more costly and provide fewer net benefits to consumers.

As explained below, State Agencies generally urge that the Commission should stay the course charted in its 2012 Policy Statement. It should continue to:

- evaluate incentive requests based on the risks and challenges facing each project;
- refrain from granting incentives—especially ROE adders—based on the expected or perceived benefits of new transmission facilities;[4]
- prioritize risk-reducing incentives over return-boosting ones; and
- evaluate incentives case by case, rather than categorically or automatically.[5]

---

[4] In New England, participating transmission owners are obligated by contract to build new facilities that ISO New England Inc. (ISO-NE) deems needed. And regardless of obligation, they are amply motivated by generous base ROEs to build new facilities and add to their rate bases. If a project does not face unusual risks and challenges, then the project likely will be built with or without an incentive. In that case, granting an ROE adder because of project benefits merely confiscates some of the benefits that consumers otherwise would enjoy and transfers them to the transmission owner.

[5] As discussed below, assuming the Commission is nonetheless inclined to move in the direction of "automatic incentives," the Commission should consider a middle-ground: a rebuttable presumption in favor of granting certain risk-reducing incentives for regionally-planned projects.

In our experience, backed by the facts on the ground, additional or more widely available incentives are not needed to meet the goals established in FPA section 219. To the contrary, as explained below, maintaining current policies with respect to project-specific incentives and phasing out (or otherwise time-limiting) ROE adders for RTO participation would better balance the goals set by section 219, including the obligation under FPA section 219(d) to ensure just and reasonable rates.

Nationwide, investments in electric transmission facilities grew from approximately $2 billion per year during the late 1990s to approximately *$20 billion per year* during the last five years.[6] A recent Brattle report attributed the trend to causes more fundamental than a proliferation of rate incentives.[7] In fact, in both New England and nationwide, the trend toward increasing investment began well before the Commission issued Order No. 679.[8] The Edison Electric Institute's (EEI) 2005 Survey of Transmission Investment found that the industry, by then, had "reversed a long-standing downward trend in transmission investment."[9] From 1999 to 2003, annual transmission investment increased at a "robust" 12 percent per year. *Id.* In July 2005, EEI predicted that transmission growth would accelerate further because RTO regional transmission

---

[6] Johannes P. Pfeifenberger, et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value* at 14-15 (2019), https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf (Brattle April 2019 Report).

[7] *Id.* at 2 ("This growth was largely in response to a growing need to meet reliability standards, to cost-effectively integrate new generating resources, and to reinforce and replace the aging existing transmission infrastructure—much of which was developed 50–60 years ago during a period of rapid economic expansion and electricity demand growth in the 1960s and 1970s.").

[8] *See* Comments of Certain State and Consumer-Owned Entities 18-20, *Promoting Transmission Investment Through Pricing Reform*, Docket No. RM11-26-000 (Sept. 12, 2011), eLibrary No. 20110912-5265 (Certain State and Consumer-Owned Entities 2011 NOI Comments).

[9] EEI, *EEI Survey of Transmission, Investment Historical and Planned Capital Expenditures* at 3 (1999-2008) (2005), https://perma.cc/N48R-EP34, at 3.

planning "compels the building-out of . . . transmission systems to maintain reliability across larger and larger market footprints."[10] EEI also pointed to utilities' and state regulators' "growing desire to diversify the generation portfolio" and "re-evaluate the role of transmission in bringing wind, coal, and hydro resources into the generation mix." EEI, *Meeting U.S. Transmission Needs* at vii. As of July 2005, ISO-NE's regional system plan already included transmission projects estimated to cost more than $3 billion.[11]

When ISO-NE became the RTO for the region, the Commission approved several mechanisms designed to promote transmission construction: (1) a contract requiring the region's transmission owners to construct facilities included in ISO-NE's regional system plan and providing abandoned- plant protections; (2) an 11.14 percent base ROE plus a 50-basis point, RTO-participation adder; and (3) a 100-basis point ROE adder on investments in new, regionally-planned facilities.[12] On rehearing, the Commission phased out the 100 basis point adder in favor of Order No. 679's case-by-case approach. *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265, P 51. And in later cases, the Commission has addressed several challenges to the regional transmission owners' base return on equity.[13]

---

[10] EEI, *Meeting U.S. Transmission Needs* at vii (2005), https://perma.cc/MTV9-E9WM; *see also* EEI, *Transmission Projects: At A Glance* at xi (2011), https://perma.cc/DF5D-YBUW ("Many of the projects in this report have an initial driver to maintain the reliability of the transmission system and meet NERC Reliability Standards (*e.g.*, the Transmission Planning TPL standards) or Transmission Owner reliability criteria.").

[11] *See* Certain State and Consumer-Owned Entities 2011 NOI Comments at 20 & n.17 (citing July '05 ISO-New England Project Listing Update (Final), ISO New England, Inc. (July 29, 2005), https://perma.cc/PT44-B8JL).

[12] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 (2006) (Opinion No. 489), *order on reh'g*, 122 FERC ¶ 61,265, P 51 (2008) (phasing out Opinion No. 489's pre-approved incentive authorization in favor of Order No. 679's case-by-case approach for projects completed after December 31, 2008), *aff'd sub nom. Conn. Dep't. of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009).

[13] *See* (1) *Coakley v. Bangor Hydro-Elec. Co.*, Docket No. EL11-66-000; (2) *ENE (Environment Northeast) v. Bangor Hydro-Elec. Co.*, Docket No. EL13-33-000; (3) *Attorney Gen. of Mass. v. Bangor Hydro-Elec. Co.*, Docket No. EL14-86-000; and (4) *Belmont Mun. Light Dep't v. Cent. Me. Power Co.*, Docket No. EL16-64-000.

Through all of this regulatory history—rife with legal challenges and attendant uncertainty—transmission investment has continued. Data gathered by Brattle, for example, show that investment levels were maintained after issuance of the 2012 Policy Statement:

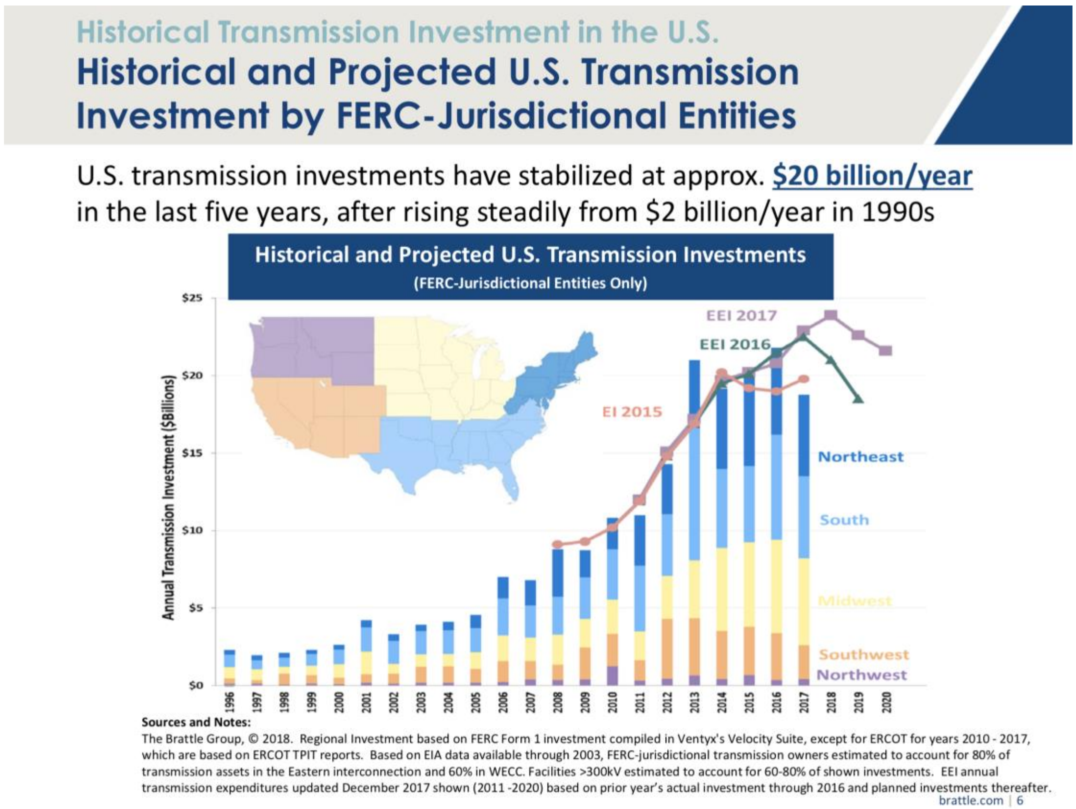

Figure 1: Johannes P. Pfeifenberger, et al., *Transmission Competition Under FERC Order No. 1000: What we Know About Cost Savings to Date*, slide 6 (Oct. 15, 2018) (Brattle October 2018 Report), https://brattlefiles.blob.core.windows.net/files/14786_brattle_competitive_transmission_wires_10-25-18.pdf.

Figure 5
U.S. Annual Transmission Investments (2010–2017)
(nominal $ billion)

	1999	2010	2011	2012	2013	2014	2015	2016	2017	2013–2017 Total	1999–2017 CAGR
CAISO	$0.33	$1.7	$0.9	$3.5	$3.2	$2.6	$2.5	$2.4	$1.8	**$12.6**	**10%**
ISO-NE	$0.09	$0.7	$0.6	$1.4	$1.8	$1.4	$1.7	$1.4	$1.2	**$7.5**	**15%**
MISO	$0.34	$1.4	$1.0	$1.3	$2.5	$2.7	$3.0	$4.0	$3.3	**$15.5**	**14%**
NYISO	$0.08	$0.5	$0.7	$0.3	$0.4	$0.5	$0.5	$0.5	$0.6	**$2.6**	**12%**
PJM	$0.46	$1.9	$3.4	$2.9	$4.1	$6.6	$7.3	$7.1	$6.4	**$31.5**	**16%**
SPP	$0.11	$0.8	$0.6	$1.2	$1.0	$2.1	$0.9	$1.4	$0.9	**$6.2**	**12%**
FERC-jurisdictional ISO/RTOs	**$1.43**	**$7.0**	**$7.3**	**$10.6**	**$12.9**	**$15.9**	**$15.8**	**$16.9**	**$14.4**	**$75.9**	**14%**
ERCOT	$0.14	$0.8	$1.2	$1.0	$5.3	$0.9	$0.9	$2.0	$1.1	**$10.2**	**12%**
U.S. ISO/RTOs	**$1.56**	**$7.8**	**$8.4**	**$11.7**	**$18.2**	**$16.8**	**$16.8**	**$18.9**	**$15.5**	**$86.1**	**14%**
Other WECC	$0.32	$1.7	$0.7	$0.8	$1.2	$0.8	$1.3	$1.0	$0.9	**$5.2**	**6%**
Southeast & Other	$0.43	$1.3	$1.8	$1.8	$1.6	$1.6	$1.9	$1.9	$2.3	**$9.4**	**10%**
Total Reported to FERC	**$2.31**	**$10.8**	**$11.0**	**$14.3**	**$21.0**	**$19.1**	**$19.9**	**$21.8**	**$18.8**	**$100.7**	**12%**

Source: The supporting data for Figures 1 and 7 show annual transmission investments made by U.S. utilities since the 1990s (see Appendix C).

Figure 2: Source: Brattle April 2019 Report, *supra* n.6, at 16.

This upward investment trend is readily apparent in New England—despite years of litigation over the proper base ROE to be used to set regional transmission rates.[14] Since 2002, roughly 800 transmission project components were placed in service in New England, while 72 more are listed as planned, proposed, or under construction in the March 2019 Regional System Plan update.[15] As of January 2019, the ISO Generator Interconnection Queue also included 17 Elective Transmission Upgrades totaling nearly 14,000 MW of potential transfer capability. *Id.* From 2000 through mid-2013, New England transmission owners invested more than $5.3 billion in over 400 transmission

---

[14] *See supra* n.13.

[15] *See* ISO-NE, *Transmission*, https://www.iso-ne.com/about/key-stats/transmission (last visited June 24, 2019).

projects.[16] And they added nearly $7.5 billion from 2013 through 2017, *see supra* Fig. 2,[17] of which about $5.9 billion was spent to improve reliability:

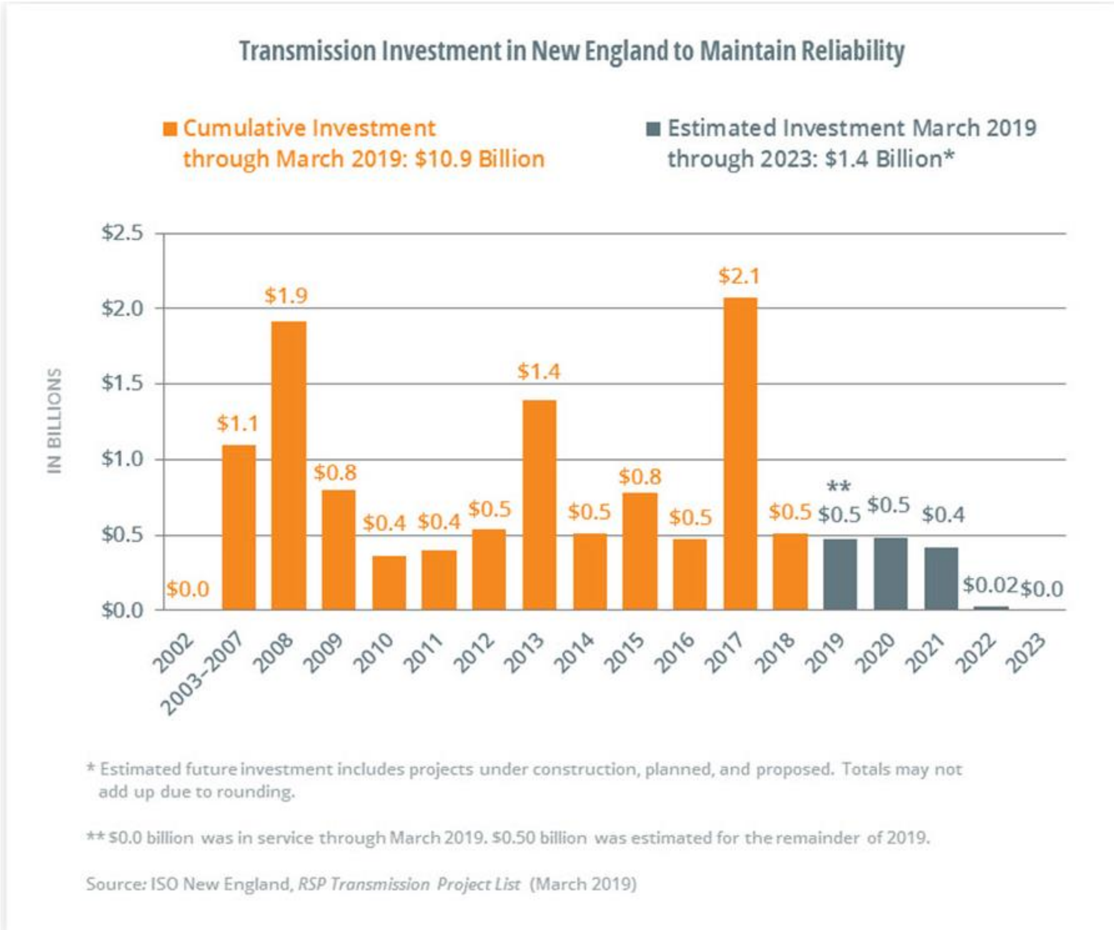

Figure 3: Source: ISO-NE, *Transmission*, https://www.iso-ne.com/about/key-stats/transmission (last visited June 24, 2019).

This level of investment helped put the Northeast Power Coordinating Council (NPCC), which includes ISO-NE, near the top in a comparison of load-weighted transmission spending among North American Electric Reliability Corporation (NERC)

---

[16] *Ten years after the 2003 Northeast Blackout, much has changed*, ISO Newswire (Aug. 13, 2013) http://isonewswire.com/updates/2013/8/13/ten-years-after-the-2003-northeast-blackout-much-has-changed.html.

[17] *See also* Brattle April 2019 Report at 60, Table 1; Brattle October 2018 Report, *supra* Figure 1, slide 8. Of those additions, roughly $5.3 billion—or 71%—was planned regionally through the ISO-NE planning process, the highest percentage of any region. Brattle October 2018 Report, slide 8.

regions.[18] And these and other investments have been beneficial, as the region's transmission congestion and reliability agreement costs have decreased dramatically:

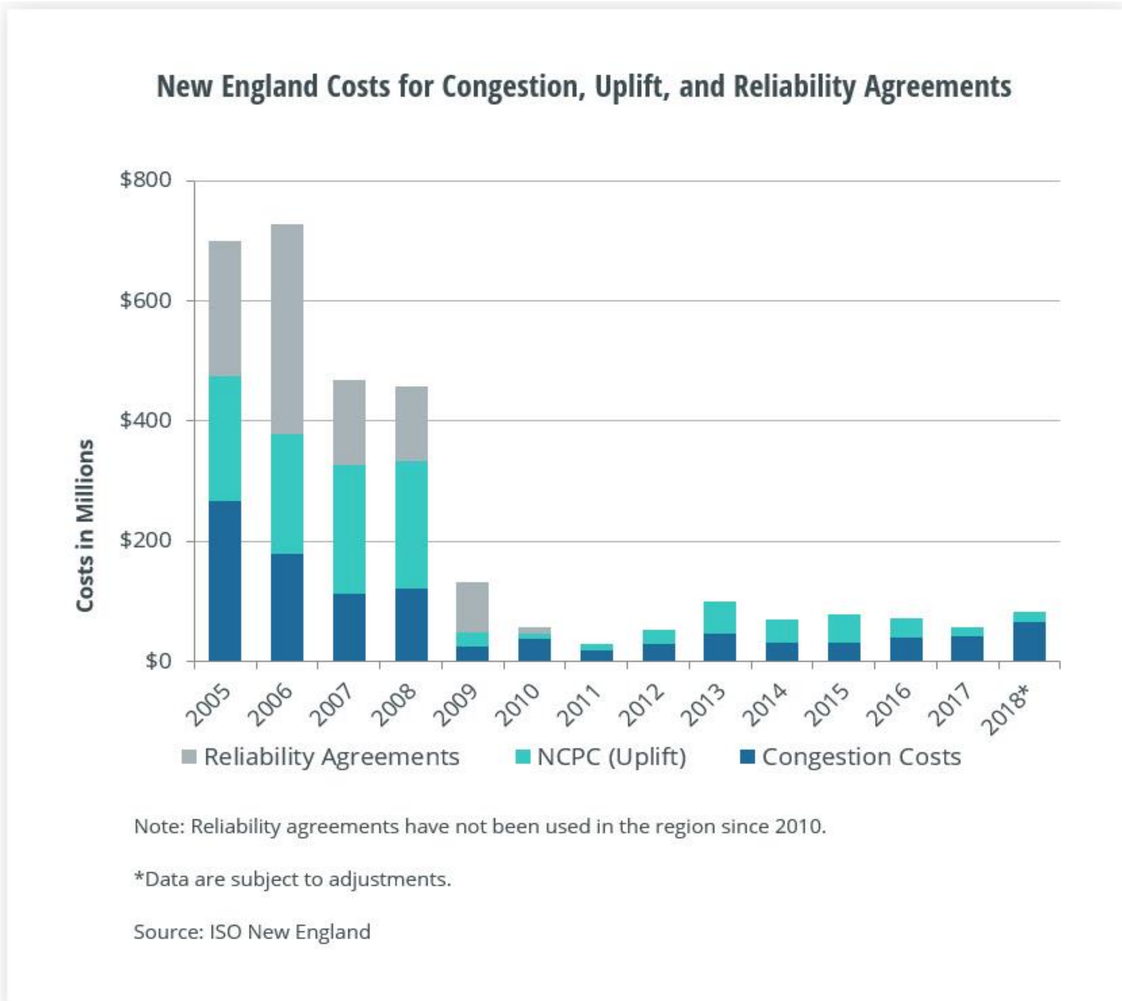

Figure 4: Source: ISO-NE, *Transmission*, https://www.iso-ne.com/about/key-stats/transmission (last visited June 24, 2019).

But the news is not entirely good. Although NPCC ranked near the top in load-weighted spending, it ranked near the bottom in terms of circuit-miles built per

[18] *Transmission Metrics: Initial Results* at 24, FERC Staff Report (2016), https://www.ferc.gov/legal/staff-reports/2016/03-17-16-report.pdf (2016 Transmission Metrics Report); *see also 2017 Transmission Metrics* at 45-46, FERC Staff Report (Oct. 6, 2017), https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf (2017 Transmission Metrics Report).

megawatt-hour of load[19] and circuit-miles per million dollars spent.[20] Thus, while New England has improved reliability and reduced congestion, it has done so at great cost—quite likely, higher cost than necessary. To date, ISO-NE is the only RTO that has yet to conduct a competitive transmission planning and procurement process, *see* 2017 Transmission Metrics Report at 19; Brattle April 2019 Report at 5,[21] which Brattle expects would yield cost savings ranging from 20% to 30% on average. Brattle April 2019 Report at 10. Competitive discipline can help in at least two ways. First, it creates pressure to plan and design projects to keep costs down, and to reflect those reductions in project bids. *Id.* at 10-11. Second, it can lead bidders to share or to take on entirely the risk of cost escalation by agreeing to caps on the amount of costs included in rates. *Id.* at 9, 30, 34.

The need for more effective cost control is especially acute in New England, where, on average, actual costs have exceeded projected costs by 70 percent—by far the nation's highest regional average. *Id.* at 52.[22] According to Brattle, ISO-NE's high average cost escalation "is due primarily to the cost escalations on three major projects—the Southwest Connecticut, Greater Springfield, and the Rhode Island Reliability

---

[19] 2016 Transmission Metrics Report at 28 & Fig. 8; 2017 Transmission Metrics Report at 48-49.

[20] 2016 Transmission Metrics Report at 29; 2017 Transmission Metrics Report at 50.

[21] ISO-NE has announced plans, however, to issue in December 2019 its first request for proposals for a competitively developed transmission solution. *See* Mem. from Vamsi Chadalavada, Executive Vice President and Chief Operating Officer, ISO-NE, to NEPOOL Participants Committee, Re-entry of retired resources and Order 1000 at 2 (April 30, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/20190430_re-entryretiredresources_order1000_memo.pdf.

[22] *See also* Brattle October 2018 Report, *supra* Figure 1, slide 14.

Projects—each of which was completed at more than twice the initial cost estimate." *Id.* at 52-53.[23]

Besides a troubling history of cost over-runs, New England also encounters other transmission issues from time to time. On occasion, projects are planned but not completed because of siting or related concerns.[24] Other times, transmission owners may plan and build facilities that might not be the most cost effective solutions to regional needs.[25] But, as we explain below, these problems are neither rooted in nor likely to be remedied by changes in the Commission's transmission incentive policy. Rather, they are failures of the transmission-planning and rate-regulation processes, which should be remedied by reforming those processes.

II. INTERESTS OF STATE AGENCIES

The **Connecticut Attorney General** (CT AG) is an elected Constitutional official and the chief legal officer of the State of Connecticut. Among the CT AG's responsibilities are interventions in various types of proceedings to protect the State, the public interest and the people of the State of Connecticut, and assuring the enforcement of a variety of laws of the State of Connecticut, including Connecticut's Unfair Trade Practices Act and Antitrust Act, so as to promote the benefits of competition and to assure the protection of Connecticut's consumers from anti-competitive abuses.

[23] The $33 million final cost for the Worcester Reliability Project was more than four times the initial $7 million estimate. *Id.* at 57.

[24] *See*, *e.g.*, Michael Casey, *Site Evaluation Committee unanimously rejects Northern Pass application*, Concord Monitor (Feb. 1, 2018), https://www.concordmonitor.com/SEC-voted-7-0-to-deny-Northern-Pass-15268899.

[25] Transmission planning can be dominated by incumbent transmission owners who seek out profitable new-build opportunities instead of measures—cheaper for consumers and less profitable for the transmission owners—to make more efficient use of existing facilities.

The **Connecticut Department of Energy and Environmental Protection** (CT DEEP) is an agency of the State of Connecticut statutorily charged with overseeing Connecticut's energy and environmental policies. Conn. Gen. Stat. §§ 22a-2d, 22a-5. In carrying out its duties, CT DEEP is tasked with the development of a comprehensive energy plan for the state, and facilitates Connecticut's transition to cleaner, more diverse and sustainable sources of energy through integrated resource planning and the conduct of power procurements to meet Connecticut's energy and environmental policies.

The **Connecticut Office of Consumer Counsel** (CT OCC) is an independent agency of the State of Connecticut and the statutory advocate for Connecticut consumers in utility matters (including the electric industry).

The **Connecticut Public Utilities Regulatory Authority** (CT PURA) is an agency of the State of Connecticut statutorily charged with regulating the rates and retail services of Connecticut's electric and gas utilities. *See* Conn. Gen. Stat. §§ 22a-2d, 16-19. CT PURA is also charged with ensuring that there are adequate and reliable electricity and gas supplies available to serve Connecticut customers. CT PURA is authorized by the General Statutes of Connecticut § 16-6a to participate in proceedings before federal agencies and courts on matters affecting utility services rendered or to be rendered in Connecticut.

The **Massachusetts Attorney General** is a public officer charged by common law and by statute with representing the Commonwealth of Massachusetts, the public interest and the people of the Commonwealth with respect to electric or gas industry matters that affect electric or gas consumers in Massachusetts. (*See* MASS. GEN. LAWS c. 12, § 10; *Feeney v. Commonwealth*, 373 Mass. 359, 366 N.E.2d 1262, 1266 (1977);

Secretary of Administration and Finance v. Attorney General, 367 Mass. 154, 163, 326 N.E.2d 334, 338 (1977). As the Commonwealth's Ratepayer Advocate, the Massachusetts Attorney General is charged with ensuring a reliable and safe power system at the lowest possible cost for all ratepayers.

III. SPECIFIC COMMENTS

State Agencies offer the following comments on certain of the specific topics and questions posed by the NOI:

A. The Commission should retain the risks-and-challenges approach, and should not award incentives based on project benefits.

1. Assessing risks and challenges remains the appropriate framework.

Q 1) *Should the Commission retain the risks and challenges framework for evaluating incentive applications?*

Q 2) *Is providing incentives to address risks and challenges an appropriate proxy for the expected benefits brought by transmission and identified in section 219 (i.e., ensuring reliability or reducing the cost of delivered power by reducing transmission congestion)? If risks and challenges are not a useful proxy for benefits, is it an appropriate approach for other reasons?*

Q 4) *Would directly examining a transmission project's expected benefits improve the Commission's transmission incentives policy, consistent with the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework?*

The NOI asks whether the Commission should retain the risks-and-challenges framework for evaluating proposed incentives, whether that framework is "an appropriate proxy for the expected benefits" of transmission investment, and, if not, whether it is an appropriate approach for other reasons. *See* NOI questions 1-2; *see also* question 4.

State Agencies believe that the Commission should continue to evaluate proposed incentives based on the risks and challenges facing a project, and should continue to favor those incentives that address those risks and challenges directly and seek to reduce them—before considering granting costly ROE incentive adders. The current approach is targeted appropriately at the obstacles that actually impede transmission development, and is calibrated to prefer incentives that directly address those obstacles at relatively low cost. Other proposed approaches risk over-paying by offering incentives not shown to be needed to induce the desired investment or behavior.

There are many reasons why a benefits-based approach to awarding incentives would be inconsistent with the Commission's FPA obligations and poor public policy. *All* prudent investment should be expected to produce net benefits; otherwise, the investment should be considered imprudent and not be pursued. Stated differently, the likelihood and magnitude of a project's net benefits compared to alternatives is what distinguishes prudent investment from imprudent investment; those factors do not show that additional incentives, beyond generous base returns on equity investment, are needed or warranted. And that is—or should be—the critical question: whether particular incentives are *needed* to induce the investment and realize the benefits. No matter how beneficial a project may be, requiring consumers to over-pay for it is unjust and unreasonable.

The reason for granting incentives is to "facilitate investment," not to "reward investments that would happen in any event." *San Diego Gas & Elec. Co. v. FERC*, 913 F.3d 127, 130 (D.C. Cir. 2019); *see also Cal. Pub. Utls. Comm'n v. FERC*, 879 F.3d 966, 970 (9th Cir. 2018) (rejecting as arbitrary and capricious a decision to give Pacific Gas & Electric Company an incentive ROE adder for remaining in the California ISO when state law prevented departure); *City of Detroit v. FPC*, 230 F.2d 810, 817 (D.C. Cir. 1955) (While the Commission may increase rates to promote beneficial conduct, "it must see to it that the increase is in fact needed and is no more than is needed."), *cert denied sub nom. Panhandle Eastern Pipe Line Co. v. City of Detroit*, 352 U.S. 829 (1956). In Order No. 679, the Commission adopted a nexus test to foreclose incentives that "increas[es] rates in a manner that has no correlation to encouraging new investment."[26] If an incentive is "not needed to encourage" investment in a beneficial project, then "the required rational relationship" between the incentive and the investment "does not exist." *San Diego Gas & Elec. Co.*, 157 FERC ¶ 61,056, P 19 (2016), *aff'd sub nom*. *San Diego Gas & Elec. Co. v. FERC*, 913 F.3d 127 (D.C. Cir. 2019).[27] *See also S. Cal. Edison Co.*, 114 FERC ¶ 61,018, P 15 (2006) (denying incentive where the utility "need[ed] no inducement" to do what the Commission wanted); *New England Power Pool*, 97 FERC ¶ 61,093, at 61,480 (2001) (denying incentive for actions the applicant had undertaken or was going to undertake anyway).

Under cost-of-service regulation, consumers compensate investors for incurring the risks associated with investment, and the net benefits that remain after investors are paid for incurring those risks should flow to consumers. The risks-and-challenges framework is useful not as a proxy for net benefits but, rather, as a means to assess when incentives beyond the base ROE are needed to induce the investment and to realize those benefits. If the base ROE and potential risk-reducing incentives would be enough to induce an investment, granting an ROE adder or benefit-sharing rate treatment does

---

[26] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057, P 6 (2006) (Order No. 679), *on reh'g*, Order No. 679-A, 117 FERC ¶ 61,345 (2006) (Order No. 679-A), *clarified*, 119 FERC ¶ 61,062 (2007).

[27] Although Order No. 679 did not require a showing of but-for causation, the D.C. Circuit emphasized the Commission's commitment to "ensure that 'incentives are not provided in circumstances where they do not materially affect investment decisions.'" *San Diego Gas & Elec. Co. v. FERC*, 913 F.3d at 138 (quoting Order No. 679-A, 117 FERC ¶ 61,345, P 25).

nothing but enrich the transmission owner and diminish the net benefits enjoyed by consumers. That result would be at odds with FPA section 219's goal of promoting incremental transmission investment at just and reasonable rates.

State Agencies also doubt it is possible to identify generically which benefits would justify incentives or the magnitude of net benefits that would justify particular types or levels of incentives. Nor do we perceive a reasonable and not unduly discriminatory or preferential way to distinguish among benefits, and identify only some that are eligible for incentives. Transmission "benefits" is a nebulous concept, and not all "benefits" can be easily monetized and compared. As components of an integrated bulk power system, transmission facilities and operations affect many things. But which effects are "benefits" depends on an observer's perspective. And the effects are rarely—if ever—direct, linear, or traceable only to the transmission facility or operation. To take one hypothetical example, a new transmission line might reduce congestion and allow the retirement of expensive generation. But if the retiring generator is a nuclear plant, stakeholders might regard the energy cost-savings benefit as offset by a likely increase of emissions (measured, perhaps, using the social cost of carbon). And both calculations—of congestion cost savings and increased emissions—depend on assumptions about the costs and emissions profiles of the replacement power supplies, which can change over time and in ways difficult to predict.

2. Base ROEs already account for most risks and challenges.

NOI question 3 asks how the Commission should distinguish, under a risks-and-challenges analysis, between those risks that are compensated through a utility's base ROE and those that warrant an ROE adder.

Q 3) *The Commission currently considers risks both in calculating a public utility's base ROE and in assessing the availability and level of any ROE adder for risks and challenges. Is this approach still appropriate? If so, which risks are relevant to each inquiry, and, if they differ, how should the Commission distinguish between risks and challenges examined in each inquiry?*

The answer can be inferred from the method by which base ROEs are computed. Base ROEs reflect company-wide risk or, more accurately, the company-wide risks of a group of proxy utilities. Base ROEs therefore reflect the overall risk resulting from the full range of the companies' activities, including projects that are riskier or less risky than average. To pay ROE adders for projects in that range, on top of a base ROE that already encompasses those risks, over-compensates the utility. Project-specific ROE adders should be reserved for investments in projects that are sufficiently risky or challenging (yet still net beneficial) that, even with risk reducing incentives, a comparable company would not undertake without an extra financial inducement. Translating this concept in Commission policy requires that the Commission adopt a rebuttable presumption that proposed projects are within the range of risk typical for a company like the applicant and compensated appropriately by the base ROE. To justify an ROE adder, an applicant should be required to show that the project is so exceptionally risky or challenging (yet still beneficial) that comparable companies have not undertaken such projects.

3. The Commission should not award benefits-based incentives automatically, without considering risks and challenges, and has better regulatory tools to encourage transmission owners to act in the public interest.

Assuming the Commission were to adopt a benefits-based approach to evaluating incentives, the NOI asks how it should be designed and implemented:

Q5) *If the Commission adopts a benefits approach, should it lay out general principles and/or bright line criteria for evaluating the potential benefits of a proposed transmission project? If so, how should the Commission* *establish the principles or criteria?*

Q 6) *How would a direct evaluation of expected benefits, instead of using risks and challenges as a proxy, impact certainty for project developers?*

Q 7) *Should transmission projects with a demonstrated likelihood of benefits be awarded incentives automatically? How could the Commission administer such an approach?*

Q 8) *If the Commission grants incentives based on expected benefits, should the level of the incentive vary based on the level of the expected benefits relative to transmission project costs? If so, how should the Commission determine how to vary incentives based on the size of benefits?*

Q 9) *Should incentives be conditioned upon meeting benefit-to-cost benchmarks, such as a benefit-cost ratio? If so, what benefit-to-cost ratios should be used?*

Q 10) *Should incentives be based only on benefit-to-cost estimates or should the Commission condition the incentives on evidence that that those benefit-to-cost estimates were realized?*

Q 11) *If an incentive is conditioned upon a transmission developer meeting benefit-to-cost benchmarks, what types of benefits and costs should a transmission developer include, and the Commission consider to support requests for such incentives? Should there be measurement and verification, and if so, over what time period? If expected benefits do not accrue, should the incentive be revoked?*

If the Commission were to adopt a benefits-based approach to evaluating incentives, NOI questions 5-7 ask how it should designed, including whether there are general principles or bright-line criteria for evaluating benefits and whether projects with likely benefits should be awarded incentives automatically. NOI questions 8-11 then ask whether incentives should vary based on the level of expected net benefits, and seeks comment on the type of evidence needed to support claimed benefits, and whether there should be a mechanism to verify that the benefits were achieved.

State Agencies do not believe that FPA section 219(d) allows the Commission to award incentives automatically to projects that are anticipated to produce certain kinds or quantities of benefits, without regard to whether the projects face risks and challenges unaddressed by base ROEs and risk-reducing incentives.[28] The reason why is simple, and consistent with both section 219 and Commission regulation to date: incentives should be available to overcome the specific risks or challenges that may impede investment in beneficial projects. Absent such risks or challenges, the project would be built even without the incentive, and granting an ROE adder or benefit-sharing rate treatment merely transfers wealth from consumers to the transmission owner.

One concern that appears to underlie many of the questions posed by the NOI is whether and how to spur actions—such as the use of dynamic line ratings or other improved operational practices—that are in consumers' best interests but do not involve large rate base additions and, so, do not offer substantial profit opportunities for transmission owners. State Agencies are sympathetic to the concern that we perceive as underlying the questions, and agree that the current misalignment of consumer and transmission owner incentives has produced sub-optimal results for consumers. But we do not view a benefits-based incentive system as the right way to address this concern.

---

[28] As explained by the D.C. Circuit in *San Diego Gas and Electric v. FERC*, the Commission's incentive policies are appropriately premised on case-by-case, fact-specific determinations:

> Transmission upgrades vary in size, complexity, and the risks and challenges they face, so no one-size-fit-all package of incentives is — or could be — secured by the Rule itself. The Incentive Rule "does not grant incentive-based rate treatments or authorize any entity to recover incentives in its rates," but only "informs potential applicants of incentives that the Commission is willing to allow when justified." Order No. 679, 116 FERC ¶ 61,057, P 20. The seven specified incentives are themselves partially overlapping and context-specific. And the eighth category — a catchall authorization of " [a]ny other incentives approved by the Commission," 18 C.F.R. § 35.35(d)(1)(viii) — underscores the Rule's contemplation of case-by-case applications based on appropriate showings, and that entitlement to an incentive rate treatment depends on an order authorizing it.

913 F.3d at 132.

There is an inherent tension between the interests of consumers who value net benefits and of transmission owners who value rate base additions and profit opportunities even if they will not yield the greatest net benefits for consumers. The NOI appears to suggest making build and non-build transmission alternatives more equal, from a transmission owner perspective, by giving the transmission owner more opportunity to profit from non-build solutions. But such a solution must be regarded as a last resort. That approach makes non-build solutions more attractive to transmission owners by making them more profitable, which means increasing their cost and making them less beneficial to consumers. The approach effectively concedes the monopolist transmission owners' ability to resist acting in consumers' best interests, and responds by paying them off—in effect, monetizing their market power. We do not favor adjusting Commission policy in this direction.

The Commission should look to more reasonable, more consumer-friendly options for meeting this objective. These would include the Commission redoubling its effort to improve regional transmission planning processes and harnessing competitive forces in pursuit of more cost-effective ways to use and, when necessary, expand the transmission system. The Commission should not consider awarding incentives to make non-build alternatives more profitable for transmission owners until it has exhausted other regulatory options.

In our view, the industry is much closer to the beginning than to the end of that road—especially in New England. Under tariff changes adopted to comply with Order No. 1000, ISO-NE is supposed to use competitive solicitations to meet new regional transmission needs.[29] But this requirement is subject to an exception for "time-sensitive need[s]" of less than three years,[30] for which the solution is to be developed and built by the incumbent transmission owner. *Id*. Att. K §§ 4.1(j)(ii), 4.2. So far, that exception has completely swallowed the rule. Each reliability need has been deemed "time-sensitive"—and thus assigned to an incumbent transmission owner—or found to be resolved by non-competitive solutions to other needs.[31] Nearly a decade after the Commission issued Order No. 1000, ISO-NE has yet to run a single competitive transmission solicitation. *Id.* While it recently announced its first potential competitive solicitation to be conducted later this year,[32] there clearly remains much room to improve the ISO-NE transmission planning process by introducing more competition. State Agencies suggest that the Commission revisit the record compiled in Docket No. AD16-18-000, and consider convening regional technical conferences—or perhaps initiating section 206 investigations—to assess the degree to which barriers to competition continue to exist in each RTO, and to consider whether tariff changes are needed to address any such impediments.

---

[29] ISO-NE, Transmission, Markets and Services Tariff, Section II, Attachment K, §§ 4.3 (Competitive Solution Process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades), 4A.5-4A.8 (solicitation process to meet identified Public Policy Requirements through Public Policy Transmission Upgrades).

[30] *See id.* Att. K § 4.1(j)(i).

[31] *See, e.g., Informational Filing of ISO New England Inc. Regarding Transmission Projects Pursuant to Section 4.1(j)(iii) of Section II of the Transmission, Markets and Services Tariff* (Jan 31, 2019), Docket No. ER13-193-000, eLibrary No. 20190131-5302 (identifying projects included in the Regional System Plan exempted from competitive solicitations due to time sensitive need); *Informational Filing of ISO New England Inc. Regarding Transmission Projects Pursuant to Section 4.1(j)(iii) of Section II of the Transmission, Markets and Services Tariff* (Jan. 30, 2018), Docket No. ER13-193-000, eLibrary no. 20180130-5338.

[32] Memorandum from Vamsi Chadalavada, Executive Vice President and Chief Operating Officer, ISO-NE, to NEPOOL Participants Committee, Re-entry of retired resources and Order 1000 (Apr. 30, 2019), https://www.iso-ne.com/static-assets/documents/2019/05/20190430_re-entryretiredresources_order1000_memo.pdf.

The Commission also should consider enhancing its oversight of the prudence of public utility transmission practices and costs so as to better ensure—without resort to expensive incentives—that public utilities are acting in their customers' interests. In *New England Power Pool*, 97 FERC ¶ 61,093 (2001), ISO-NE, New England Power Pool (NEPOOL), and National Grid sought approval of incentives relating to the refurbishment of a 345kV line. Instead of taking the line out of service and conducting maintenance (expected to cost $1.3 million), the applicants proposed to keep the line in service while performing the maintenance. *Id.* at 61,478. The live-line maintenance would cost more—about $1.8 million—but would keep the line in service and avoid "far greater" increases in energy costs. *Id.* The applicants proposed a split-the-savings incentive: customers would keep all of the first $500,000 of energy cost savings; NEP would receive 50% of savings between $500,000 and $3 million and 25% of savings above that amount. *Id.*

The Commission agreed that live-line maintenance was the most cost-effective approach to refurbishing the line. But it did not follow that incentives were required or warranted to induce that behavior:

> Prudence requires that a utility conduct maintenance so as to provide service at the lowest reasonable total cost. As intervenors note, live-line maintenance is a well-established practice, and in this instance appears to be the lowest-cost alternative maintenance method. [New England Power (NEP)] has not claimed that live-line maintenance is in any way innovative. Under existing cost-recovery methods, NEP would fully recover its costs of performing live-line maintenance; we see no reason to pay an incentive premium for performing such non-innovative procedures.

Id. at 61,479-80. The Commission explained that it expects "all maintenance procedures" to conform to good utility practice and to "minimize total costs." *Id.* at 61,479. The

Commission explained that it would "seriously question the prudence of any costs incurred for maintenance procedures that only took account of transmission owner's out-of-pocket costs" and did not consider other ratepayer costs and benefits. *Id*.

In regions where transmission planning and development is not subject to effective competition, this precedent offers a framework to align the interests of transmission owners and their customers without resorting to incentive ROE adders or split-the-savings incentives. Following the statements in *New England Power Pool*, the Commission might well question the prudence of transmission costs to build new facilities or upgrade existing ones, where the need could have been met at lower cost by improved operations (such as using dynamic line ratings) or installing less expensive equipment (e.g., to control power flows).

B. The Commission should not grant incentives using project characteristics as a proxy for expected benefits.

Q 12) *How, if at all, would examining transmission projects' characteristics in evaluations of transmission incentives applications improve the Commission's transmission incentives policy and achieve the goals of section 219? Are there drawbacks to this approach, particularly relative to the current risks and challenges framework? Would this approach result in different outcomes, as compared to the current risks and challenges approach for granting incentives?*

Q 13) *If the Commission adopts an approach based on project characteristics, should it lay out general principles and/or bright line criteria for identifying or evaluating those characteristics?*

Q 14) *If so, how should applicable criteria be established, and, in cases where more than one criterion applies, how should they be evaluated in combination?*

Q 15) *How would an approach based on project characteristics impact certainty for project developers, particularly relative to the current risks and challenges framework?*

Q 16) *Should transmission projects with certain characteristics be awarded incentives automatically? How could the Commission administer such an approach?*

The NOI asks whether, instead of "direct examination of expected benefits," the Commission should award incentives using "transmission project characteristics as a proxy for expected benefits." NOI P 18. State Agencies do not favor awarding incentives using transmission project characteristics as a proxy for expected benefits. We explained above why in our view the NOI poses the wrong question. Incentive decisions should not turn on whether a transmission project is expected to produce "benefits" (assuming that term can be defined and applies in a reasonable and not unduly discriminatory way). Rather, the question should be whether particular incentives are *needed* in order to induce the investment or action and *realize* the expected benefits. A benefits-based analysis skips over the crucial question. A characteristics-based analysis skips that question, too, and introduces an even further leap. What determines a project's benefit is not its characteristics but, rather, the *fit* between those characteristics and the need that gave rise to the project.[33] But needs vary from place to place and time to time. The NOI identifies no class of facilities that, across all circumstances, the Commission believes should be built, is not being built today, but is more likely to be built if awarded incentives.

State Agencies do not believe it is possible to identify such a class generically. Rather, the need to ensure that each incentive "actually serves Congress's objective of benefiting consumers" means that each incentive request must be scrutinized based on its facts. *San Diego Gas & Elec. Co.*, 913 F.3d at 133.

C. The Commission should not award incentives solely because a project is expected to achieve certain objectives.

The NOI seeks comment on "what expected benefits or project characteristics warrant incentives," NOI P 20, and lists certain possibilities. With respect to each benefit or characteristic, the NOI asks commenters to consider how the benefit or characteristic

---

[33] Pencillin is a beneficial drug, but will not cure a headache. Many car purchasers value fuel efficiency, but that characteristic may be of little value to Formula 1 drivers or to those who drive infrequently.

should be defined and measured, what incentives are appropriate, and their respective legal bases. *Id*.

1. Reliability

Q 17) *Should the Commission tailor incentives to promote these types of projects based on their expected reliability benefits? If so, how should the Commission differentiate these projects from others required to meet reliability standards?*

Q 18) *Are there specific reliability benefits or project characteristics that could merit such an approach?*

Q 19) *If the Commission tailored incentives for reliability benefits, how should the Commission measure the expected enhancement to transmission reliability? Should there be a threshold or bright line test applied? If so, how?*

As the NOI explains, "[t]ransmission owners are already required to address many facets of reliability through compliance with the [NERC] reliability standards and various other planning criteria." NOI, P 22. The Commission should not award incentives—especially not ROE adders—for projects needed to meet these standards. Satisfying mandatory reliability requirements should be at the heart of a transmission owner's obligation to operate prudently and consistent with good utility practice. Projects needed to meet these standards therefore should fall well within the range of activities compensated by a transmission owner's base ROE.

The NOI asks whether incentives should be provided to projects that "significantly enhance transmission reliability above and beyond what is required by NERC reliability standards or other planning criteria." NOI P 22. State Agencies do not support this suggested policy change. NOI questions 17-19 appear to assume that there are projects that (a) are not required to meet such standards, (b) would provide incremental reliability benefits, (c) are cost-effective, but (d) would not be pursued absent incentives. This seems unlikely, and the NOI does not identify any such projects.

More fundamentally, it is important to recognize that NERC requirements and ISO-NE planning criteria *already* reflect implicit judgments about the appropriate tradeoff between reliability and cost—arguably erring on the side of more reliability. The Commission does not assert that transmission owners (TOs) nationwide are failing to make adequate investments in reliability improvements. Likewise State Agencies are unaware of any New England transmission owner that is neglecting its reliability-based responsibilities. Nor has any expressed a plausible view that reliability is at risk absent the receipt of incentives. We think that a greater concern than any diminution in reliability that might occur absent these incentives is that offering them for "incremental" improvements invites system gold-plating. This is particularly worrisome where the projects at issue are pursued outside of regional transmission planning, and are not subject to the checks and balances inherent in those processes.

If the Commission nonetheless decides to adopt "tailored incentives for reliability benefits," (question 19), their receipt should be dependent upon several showings. At a minimum, these would include requiring the applicant to: (1) demonstrate how the project provides reliability benefits to customers that exceed those obtained by meeting mandatory requirements; (2) identify and quantify any such benefits, and (3) show that the claimed benefits are in some sense "real," *i.e.* that they are not merely the product of system gold-plating.

2. Economic efficiency

Q 22) *Should the Commission tailor incentives to promote projects that accomplish the outcomes of reducing congestion or facilitating access to additional generation?*

Q 23) *Should the Commission establish bright line metrics, such as a specified level of reduction in average production costs, to determine whether a transmission project merits incentives?*

Q 24) *Should the Commission consider incentivizing transmission projects that are scaled to more efficiently facilitate interconnection of, or transmission to, additional generation? What other measurable economic efficiency benefits should be considered a bright line metric for the purposes of economic efficiency?*

Q 25) *How should the applicable bright line criteria be established, and, in cases where more than one criterion applies, how should they be evaluated in combination?*

The NOI asks whether the Commission should tailor incentives to promote projects that reduce congestion or facilitate the "the transmission of additional generation to load centers." NOI P 24. The short answer is no. As noted above, New England's transmission owners already are motivated by lucrative base ROEs to build cost-effective transmission. They also are obligated to build certain facilities needed for reliability, which, when built, also may reduce congestion or facilitate transmission of additional generation to load centers. As shown above, New England has seen a decades-long surge in transmission investment, particularly for reliability, which also has reduced congestion substantially. There has been no showing of any need to require consumers to pay more for what they will be getting anyway.

Similarly, while additional transmission facilities can produce benefits besides reducing congestion, such as enabling emission-free energy to reach load centers, we do not believe special incentives are needed to achieve those benefits. New England's TOs already are both adequately motivated to build without ROE adders and obligated by contract as part of the ISO/RTO design to build facilities identified in the regional plan.[34]

[34] As noted above, the Commission has rejected the notion that consumers should be obligated to pay incentives to transmission providers who are doing only what they are already being paid to do. *New England Power Pool*, 97 FERC ¶ 61,093, at 61,477 (rejecting proposed "Transmission Incentive Pilot" after finding that it was not "in the public's interest … [to] unjustly reward NEP [New England Power] for doing what it is supposed to do, i.e., to adequately maintain its facilities in a prudent, cost-effective manner"). While Order No. 679-A held that "[i]n general, . . . contractual commitments or mandatory projects, such as section 215 reliability projects, [do not] disqualify a request for incentive-based rate treatment," it also held that such commitments could have a bearing on the nexus between the incentive and the investment. Order No. 679-A at P 122. Respectfully, we submit that requiring transmission customers to

More broadly, to the extent there are hurdles to a particular new construction project, there is no basis for believing that ROE adders are likely to overcome them. For example, the Northern Pass project was vigorously pursued for years but failed to obtain siting approval from New Hampshire regulators (in early 2018) because of concerns about local impacts, and there is no reason to believe that the availability of an ROE adder would have changed that outcome. Moreover, all else being equal, a higher estimated price tag presumably makes it more difficult to achieve siting approval—an outcome directly contrary to the intent of the NOI.

ROE adders likewise are neither needed nor appropriate to incentivize projects that are "scaled to more efficiently facilitate interconnection of or transmission to additional generation." *See* NOI question 24. Questions of scale should be decided through the transmission planning process, and not by offering higher returns on what already is likely to be a relatively larger rate base addition. To the extent projects are built outside of the planning process, they should not be eligible for ROE adders. State Agencies continue to believe that, as concerns New England, any policy changes related to transmission should be focused not on broadening incentives, but on steps to support the use of regional transmission planning processes to select cost-effective new transmission and non-transmission alternative solutions to regional needs.

3. Addressing persistent geographic needs

Q 26) *Should the Commission utilize an incentives approach that is based on targeting certain geographic areas where transmission projects would enhance reliability and/or have particular economic efficiency benefits? If so, how should the*

---

pay bonuses to ensure the construction of facilities that transmission owners are already obliged to build is neither just and reasonable nor consistent with the Ninth Circuit's approach in *Cal. Pub. Utils. Comm'n v. FERC*, 879 F.3d 966, 970 (9th Cir. 2018), which emphasized that incentives are needed only to induce *voluntary* behavior.

relevant geographic areas be identified and defined? What entity (e.g., the Commission, RTOs/ISOs, state regulators, other stakeholders) should designate such areas?

Q 27) *What criteria should be used to define such geographic areas? Procedurally, how should such geographic areas be determined, monitored, and updated?*

Q 28) *Should the relevant geographic areas be defined on an ex ante basis and/or should the transmission developer have the burden of demonstrating that the relevant transmission project falls within a geographic region that has an acute need for transmission?*

The NOI asks whether the Commission should adopt incentives targeting geographic areas experiencing chronic congestion or relying on operating procedures to address long-term reliability issues. In general, the Commission should not define geographic areas in which incentives are offered automatically—especially not in New England, where a regional planning process is in place to address such concerns.

As FERC staff recognized in its transmission metrics reports, it is not always cost-effective to build new facilities to resolve chronic congestion or reliability issues. E.g., 2016 Transmission Metrics Report at 23. When new transmission is more costly than the congestion or reliability issue it would address, the new facility should not be built—let alone be rewarded with incentives to encourage construction. *Id.* Besides, Staff's transmission metrics reports identified no areas in New England with significant, persistent price differences.[35]

State Agencies' experience under the current incentive policy is that where chronic issues emerge that would be cost-efficient to fix by building new transmission,

[35] Staff compared the 5th and 95th percentile prices at each node with the corresponding market-wide percentile prices. Staff identified nodes with high prices more than a standard deviation above the market-wide 95th percentile price and low prices more than a standard deviation below the market-wide 5th percentile price. Staff found about a dozen areas in RTO regions with persistently high or low prices from 2012 through 2017, but none were in New England. *See* 2016 Transmission Metrics Report at 15-16; 2017 Transmission Metrics Report at 34-36.

the region's transmission owners will step up and be ready to build it. And if for some reason the relevant transmission owner fails to do so, the potential correct responses are to conduct a competitive solicitation, enforce the obligation to build set forth in the Transmission Operating Agreement, or reduce the transmission owner's base ROE to reflect its sub-standard performance. The Commission should not require customers to pay bonuses to induce transmission owners to do what they should be doing anyway.

4. Flexible transmission system operation

Q 29) *How can flexibility characteristics improve the operation of the transmission system?*

Q 30) *Should the Commission incentivize flexibility characteristics and, if so, how should it do so?*

Q 31) *How could the Commission define "flexibility" in this context?*

Transmission lines are stationary, long-lived, capital-intensive assets. Yet, as the NOI observes (P 26), transmission system demands evolve as the generation mix and load patterns change. The NOI posits that some facilities or practices, such as "increased line rating precision, greater power flow control, and technologies, including energy storage, may be able to facilitate the transmission system's ability to respond to changing circumstances." *Id.* The NOI asks how flexibility characteristics could improve transmission system operations, how to define flexibility, and whether to incentivize it. *Id.*

Both the generation mix and net load patterns (load not served by behind-the-meter generation) are changing, and the pace of change is likely to accelerate. Given these circumstances, transmission system flexibility is an important and beneficial characteristic. The pace and unpredictability of change should make planners and regulators wary of capital-intensive solutions to reliability concerns, congestion, or other issues, as their value may diminish over time because of anticipated changes in generation and load patterns. And where new transmission facilities are required, they should be designed to the extent feasible in ways that enable them to be used flexibly and adapted, upgraded, or modified readily.

Solutions that feature these characteristics should be identified, elicited, and prioritized through the transmission planning process and, where appropriate, through the conduct of competitive transmission solicitations. As part of such processes, a project's claimed value can be fully vetted, assessed in relation to its costs, and compared with other alternatives. Where issues can be addressed by changing operational practices or solutions with lower fixed costs, such options should be considered first. State Agencies assert that focusing on planning processes should result in the procurement of flexible solutions *without* the need to offer ROE adders or similar financial incentives.

5. Security and resilience

Q 32) *Should the Commission incentivize physical and cyber-security enhancements at transmission facilities? If so, what types of security investments should qualify for transmission incentives? What type of incentive(s) would be appropriate?*

Q 33) *How should the Commission define "security" in the context of determining eligibility for incentive treatment? For example, should the Commission define security based on specific investments or based on performance of delivering increased security of the transmission system?*

Q 34) *Should transmission projects that enhance resilience be eligible for incentives based upon their reliability-enhancing attributes?*

Q 36) *If the Commission were to grant incentives for measures that enhance the resilience of the transmission system, what incentive(s) would be appropriate?*

The NOI asks whether FERC should incentivize projects that enhance the transmission system's physical or cyber-security (P 27) or resilience (P 28).[36] The NOI

---

[36] FERC has proposed to define resilience as "the ability to withstand and reduce the magnitude and/or the duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly

further asks how FERC should define those attributes and measure a project's contribution toward them, which projects should qualify for incentives, and which incentives are appropriate. *Id.*

NERC and the regional electric reliability organizations already have in place physical and cyber-security requirements. Each ISO/RTO may have additional relevant planning or operations requirements. Some of these organizations also address aspects of resilience—for instance, by adopting requirements intended to limit cascading outages and by procuring black start services. FERC has authority to review mandatory reliability standards promulgated by NERC, and likely has more direct authority over practices embedded in RTO or public utility tariffs or that directly affect service under those tariffs. To the extent FERC believes that baseline physical and cyber-security or resilience requirements are too lax, it should take steps within its jurisdiction to elevate the standards.

State Agencies have seen no indication of an unwillingness (or even hesitance) of the part of transmission owners to make needed investments in cyber-security. And, again, the Commission should not provide incentives for investments to comply with any mandatory standards. To the extent a project would provide incremental benefits that go beyond those standards, we are concerned that making incentives available for them would invite system gold-plating.

6. Improving existing transmission facilities

Q 37) *How should the Commission incentivize the deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission*

---

recover from such an event." NOI P 28, quoting *Grid Reliability and Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 162 FERC ¶ 62,012, P 23 (2018).

grid? How can the Commission identify and quantify how a technology or other measure contributes to those goals? Please provide examples.

Q 38) *Can the Commission distinguish between incremental improvements that merit an incentive and those maintenance-related expenses that a transmission owner would make in its ordinary course of business?*

Q 39) *How should a transmission owner seeking this type of incentive demonstrate increases or improvements in the capabilities or operations of existing transmission facilities?*

Q 40) *Should the Commission provide a stand-alone, transmission technology-related incentive? If the Commission provides a stand-alone transmission technology-related incentive, what criteria should be employed for a technology to be considered as meriting an incentive? Should the Commission periodically revisit the definition of an eligible technology?*

State Agencies support efforts to improve "the capacity, efficiency, and operation of the transmission grid" without the need for new—and unnecessary—transmission plant. We do not see, however, that awarding more transmission incentives is the most cost-efficient way to accomplish this objective.

The Commission should use the transmission planning process and competitive solicitations to advance these goals and select appropriate solutions. When the RTO identifies a need, the transmission planning process should consider whether it can be satisfied by technologies or measures that improve the performance of existing transmission facilities. If that can be done at lower cost than a new facility, the planning process should select that solution. The Commission should review each RTO's planning process and require changes where necessary to promote more competitive solicitation of solutions to identified needs. Reliance on competitive processes could prompt improvements to an existing facility even if its owner neither agrees—nor can be required—to allow competitively-selected third parties to install the improvement. Incumbents facing competition for new-build opportunities may prefer to offer improvements to their existing facilities, despite the relative modesty of any rate base addition, rather than risk losing the competition and forgoing any rate base opportunity.

Q 41) *Certain utility costs, such as those associated with grid management technology, including dynamic line rating technology, are typically recovered through operations and maintenance expenses within cost-of service rates. For such costs, should the Commission, instead, consider inclusion of these expenses in rate base as a regulatory asset? If so, what costs should be eligible for such treatment and over what period should they be amortized?*

State Agencies regard it as premature to consider whether to rate base costs associated with grid management technology as an incentive to promote adoption of the technology. We urge the Commission first to adopt the transmission planning reforms discussed above, which we are hopeful will lead to full and fair consideration of grid management technology options as part of the regional planning process. If those reforms fail to result in the adoption of cost-effective technologies, the Commission should investigate the reasons for the failure and consider disallowing as imprudent any system-expansion costs that could have been avoided or delayed using these technologies. At that time, if appropriate, the Commission could consider, alternatively, whether it would be just and reasonable to remove a perceived barrier to deployment of these technologies by letting transmission owners include the costs in rate base. That step is not warranted now.

Q 42) *Are there ways the Commission could incentivize RTOs/ISOs to adopt better grid management technologies and/or other technologies to improve the efficiency of individual transmission assets to promote efficient use of the transmission system and improved market performance?*

State Agencies oppose "incentivizing" RTOs and ISOs to adopt better grid management techniques. These goals can instead best be accomplished by ensuring that regional transmission planning processes administered by RTOs/ISOs require the identification and scrutiny of grid management and related efficiency-enhancing technologies. To enforce this requirement, the Commission could consider requiring RTOs to report annually or biannually on the extent to which each is adopting better grid management technologies or practices. The Commission should likewise allow an opportunity for public comment on these reports. Over time, such reports should disseminate information about best practices and create pressure for their adoption.

7. Unlocking locationally constrained resources

Q 47) *Should the Commission use incentives to encourage the development of transmission projects that will facilitate the interconnection of large amounts of resources?*

Q 48) *If so, what metrics could the Commission consider when evaluating whether a transmission project facilitates the interconnection of generation?*

Q 49) *Should such an incentive focus on resources already in the queue, a region's potential for new resources, or some other measure? How could the Commission evaluate the potential for further resource development in a particular geographic area?*

The NOI notes that "interconnection queues in many regions of the country have expanded considerably, with many of the potential resources clustered in specific geographic areas with limited transmission access." NOI P 31. The NOI asks whether (and, if so, how) the Commission should use incentives to encourage development of transmission projects that facilitate interconnection of many resources. *Id*.

The NOI itself observes that this phenomenon has occurred even though the 2012 incentives Policy Statement made transmission projects that unlock location constrained resources eligible for incentives. *Id.* In our view, the problem (to the extent it exists in New England) is not caused by insufficient incentives, nor will it be fixed by expanding their availability. Moreover, such an approach could raise questions of undue discrimination as the Commission chooses which interconnections to expedite (thereby accelerating some generators' market access). Again, the best way to promote appropriate projects to connect new areas of developing generation is through regional transmission planning processes, not by awarding incentives.

8. Order No. 1000 transmission projects

Q 52) *Should these or other incentives be granted automatically for transmission projects selected in a regional transmission plan for purposes of cost allocation?*

Q 53) *If so, what specific incentives are appropriate for such automatic treatment and how should such incentives be designed?*

The NOI asks whether the Commission should establish a rebuttable presumption pre-approving risk-reducing incentives (such as Construction Work In Progress (CWIP) treatment, abandoned plant protection, or regulatory asset treatment) for "transmission projects selected in a regional transmission plan for purposes of cost allocation," i.e., regionally-planned projects. NOI P 33.

State Agencies favor the continued treatment of all incentives on a case-by-case basis and do not support awarding certain incentives for projects that result from a regional planning process. If the Commission is nonetheless inclined to adopt a rebuttable presumption of eligibility for CWIP and abandoned-plant incentives for regionally planned projects, the Commission should likewise make clear that any expansion in the use of risk-reducing incentives will further reduce the recipients' risks—a reduction that should be reflected in lower base ROEs.

Q 54) *Should the Commission continue to use certain incentives to seek to place non-incumbent transmission developers on a level playing field with incumbent transmission owners in Order No. 1000 regional transmission planning processes? If so, should the Commission consider requests for such incentives under section 205, or should the Commission consider requests for such incentives for non-incumbent transmission owners under section 219?*

The NOI asks (P 34) whether the Commission should continue using certain incentives (such as hypothetical capital structures) to seek to place non-incumbent transmission developers on a level playing field with incumbents in the Order No. 1000 regional transmission planning process. State Agencies suggest that the Commission take steps to promote competition for transmission development, and continue to assess on a case-by-case basis whether non-incumbents face disincentives that should be ameliorated using incentives, such as a hypothetical capital structure or regulatory asset treatment of pre-commercial costs. The Commission should not pre-approve such incentives.

The NOI also asks whether development costs for projects not selected through the regional planning process should be eligible for these incentives. NOI P 40 (and related Question 72). State Agencies do not favor permitting either incumbents or non-incumbents to recover costs of unsuccessful proposals as of right. Those seeking recovery should be obligated to make a filing with the Commission and, on a case-by-case basis, seek to obtain authorization to do so.

D. THE RTO/ISO PARTICIPATION ADDER SHOULD BE REVISED.

Q 61) *Should the Commission revise the RTO-participation incentive?*

Q 62) *Should the Commission consider providing incentives other than ROE adders for utilities that join RTO/ISOs, such as the automatic provision of CWIP in rate base or the abandoned plant incentive for all transmission-owning members of an RTO/ISO? If so, what other types of incentives would be appropriate?*

Q 63) *If the Commission continues to provide ROE adders for RTO/ISO participation, what is an appropriate level for an ROE adder?*

Q 64) *Should the RTO-participation incentive be awarded for a fixed period of time after a transmission owner joins an RTO or ISO?*

Q 65) *Should the RTO-participation adder be awarded on a project-specific basis*?

Q 66) *In Order No. 679, the Commission found that "the basis for the incentive is a recognition that benefits flow from membership in such organizations and the fact that continuing membership is generally voluntary." Should voluntary participation remain a requirement for receiving RTO/ISO incentives*?

The Commission poses a series of questions concerning the RTO/ISO participation adder, including, most fundamentally, whether the adder should be revised. State Agencies' answer is "yes."

When RTO/ISO formation was in its early stages, a participation adder arguably had value as an encouragement to potential members. But, two-plus decades after the formation of ISO New England and 15 years after the implementation of the region's participation adder,[37] we believe that the membership bonus has done its job, outlived its usefulness, and at this point is an unwarranted—and significant—windfall. Going forward, State Agencies see no reasonable basis for continuing to reward New England's transmission owners for maintaining their membership in ISO-NE. There should be no dispute that the region's transmission owners have concluded that being a part of the ISO structure is of value to them—none has sought to withdraw their facilities or otherwise cancel their membership or suggested that it would do so if the 50 basis point adder were phased out. At least as concerns New England—if not elsewhere—there is no reasonable basis to continue to require customers to pay the TOs to take an action that they have themselves concluded is in their collective self-interest.

State Agencies suggest that the RTO/ISO participation adder be revised as follows. First, the adder should be eliminated immediately for any transmission owner whose participation is mandated. The Commission should not incentivize behavior that will happen whether or not an incentive is awarded. Second, for those transmission

---

[37] In 2004, the Commission approved a 50 basis point adder for RTO membership, which is included as part of the base ROE rate, and charged against the entire (and growing) New England transmission rate base. *Bangor Hydro-Elec. Co.*, 106 FERC ¶ 61,280, P 245 (2004). *See* ISO-NE Transmission, Markets, and Services Tariff, Attachment F (Implementation Rule) §II.A.2.(a)(iii).

owners who are current, voluntary RTO/ISO members, the participation adder should be eliminated over a two-year phase-out period. We suggest that the adder be cut in half (to 25 basis points) after the first year, and eliminated entirely after the second year. Third, for any future RTO/ISO members who are deemed eligible to receive a 50 basis point adder, the adder should sunset after ten years. State Agencies also would oppose the imposition of either any additional RTO-participation incentive or project-specific participation adder. Project-specific adders (e.g., CWIP, abandoned plant) should be awarded, if at all, on a case-by-case basis (where justified to address project-specific risks and challenges).

We note that revising the RTO/ISO participation incentive adder in this fashion would be consistent with the Commission's statutory responsibility. FPA section 219(c), 16 U.S.C. 824s(c), requires that the Commission "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization." The provision nowhere says that any such incentive must be perpetual.

E. THE ADVANCED TECHNOLOGY ADDER SHOULD CONTINUE TO BE ADDRESSED UNDER THE 2012 POLICY STATEMENT.

Q 67) *Why have few transmission developers sought transmission incentives for the adoption of advanced technology?*

Q 68) *Do NERC reliability standards affect the willingness of transmission developers to enhance existing transmission facilities by deploying new technologies because of concerns these technologies may increase the risk of standards violations?*

Q 69) *Are there any types of transmission incentives that could better encourage deployment of new technologies? If so, please describe them.*

The NOI questions why there have been few requests for an advanced technology waiver (question 67); whether NERC reliability standards have had an impact on the deployment of new technologies (question 68); and whether there are other types of incentives that might better encourage deployment (question 69).

State Agencies take no position on the first two questions, which are aimed at the transmission developers. As for whether there are better incentives for advanced technologies, we suggest that the Commission continue the approach in the 2012 Policy Statement, which eliminated a standalone advanced technology adder, and announced an intention to treat it as "indicative of the types of projects facing risks and challenges that may warrant an incentive ROE. As a result, we will consider deployment of advanced technologies as part of the overall nexus analysis when an incentive ROE is sought." 2012 Policy Statement P 23.

F. The Commission generally should stay the course as to non-ROE incentives, but could consider adopting rebuttable presumptions in some situations.

1. CWIP and Regulatory Asset/Deferred Recovery of Pre-Commercial Costs

Q 70) *Should the Commission continue to provide regulatory asset treatment and CWIP as incentives? Should these incentives be granted automatically to certain types of transmission projects? If so, how would the Commission determine what types of transmission projects?*

Q 71) *Should the costs of unsuccessful Order No. 1000 proposals be recoverable through regulatory asset and deferred pre-commercial cost recovery incentives? If so, what costs are appropriate for recovery?*

The NOI asks whether FERC should continue granting CWIP and regulatory-asset treatment of pre-commercial costs; whether it should grant those incentives automatically for certain kinds of projects; and whether to apply the incentives to development costs of projects not selected through the regional planning process. *See* NOI P 40.

As explained earlier, the Commission could consider employing a rebuttable presumption of eligibility for CWIP and abandoned-plant incentives for regionally planned projects. But this presumption could be overcome by a showing that a specific project does not require these incentives. And, again, we would note that if the Commission is willing to ease the path toward the receipt of such risk-reducing incentives, that expansion in their use will further reduce the recipients' risks—a reduction that should be reflected in lower base ROEs.

In response to question 71, State Agencies oppose treating the development costs associated with unsuccessful projects as eligible for incentive treatment. We believe that the combination of a just and reasonable base ROE, formula transmission rates, and a sound regional planning process—that includes a broader and more appropriate use of competitive solicitations—should provide more than sufficient incentive for transmission developers to do what they are supposed to be doing: pursuing the development of new projects. We agree that incumbent and non-incumbent transmission owners must face the same rate treatment. But the Commission should not resolve any disparity by making things worse for consumers; the Commission should make them better. Neither incumbents nor non-incumbents should be able to foist on consumers the costs of their unsuccessful proposals.

2. Hypothetical capital structures

Q 72) *Should the Commission continue to utilize hypothetical capital structures as a transmission incentive? If so, what entities should be eligible to apply for a hypothetical capital structure?*

Q 73) *Have hypothetical capital structures been effective in reducing the overall cost of debt by rendering the capital structure more predictable?*

Q 74) *In what circumstances, if any, should hypothetical capital structure incentives granted to an entity also be authorized for that entity's yet-to-be formed affiliates?*

Q 75) *Under what circumstances, if any, should hypothetical capital structures extend beyond the construction period?*

Q 76) *Should the Commission provide a consistent hypothetical structure (e.g., 50 percent debt and 50 percent equity)? Alternatively, should the Commission cap the equity percentage at some upper limit (e.g., 50 percent)?*

The NOI states that FERC "currently approves hypothetical capital structures during the construction period, chiefly for small or new transmission owners" and for "non-public [non-jurisdictional] utilities without traditional capital structures." NOI P 41. The NOI asks whether this policy has been effective in reducing cost of debt, and whether, when, and how FERC should continue to use hypothetical capital structures as a transmission incentive. *Id.*

Absent a further showing, State Agencies see no need to change the Commission's current policy on these issues. The Commission should continue to assess requests for use of hypothetical capital structures on a case-by-case basis and to permit their use where justified.

3. Recovery of prudent investment in abandoned plant

Q 77) *Should the Commission grant the abandoned plant incentive automatically, rather than on a case-by-case basis? Under what circumstances might an automatic award of the abandoned plant incentive be appropriate?*

Q 78) *How, if at all, could the Commission grant the abandoned plant incentive without encouraging transmission developers to pursue unnecessarily risky transmission projects or take unnecessary risks in transmission development? Could such behavior be reduced if the developer shared some risk associated with the abandonment, e.g., 10 percent of abandonment costs? If so, what level of developer risk is appropriate?*

Q 79) *How should the Commission evaluate whether the costs of an abandoned facility were prudently incurred?*

For some projects, the Commission has pre-approved recovery of prudently incurred costs if the facilities are later abandoned or canceled. NOI P 42. The NOI asks a series of questions involving whether to continue to do so; whether to offer the incentive automatically, rather than case-by-case; how the Commission can avoid incentivizing unnecessarily risky projects or decisions; and how it should evaluate whether costs of an abandoned facility were prudently incurred. *Id.*

As stated earlier, State Agencies do not favor "automatic" incentives, and believe that it is sound policy for the Commission to continue to review requests for any incentive—whether ROE adder or risk-reducer—on a case-specific basis. If the Commission chooses to go in a different direction, however, then any such incentive should be limited to projects that were selected through a regional transmission planning process. In addition, the incentive should be limited so that it applies only to prudently incurred costs that are consistent with project schedules and cost estimates on the basis of which the project was selected through the regional transmission process. Prudently incurred costs above what was estimated for the project phases undertaken should remain only 50% recoverable, consistent with Commission policy absent an incentive.

G. The Commission should adopt mechanics and implementation rules that reinforce nexus requirements and tie incentives to the bases for granting them.

1. Incentive duration

The NOI asks (P 44) whether particular types of incentives should automatically sunset and under what certain circumstances. Specifically:

Q 83) *Should the Commission limit the duration of a granted transmission incentive? If so, should this limit be based on the type of incentive granted?*

Q 84) *How should the Commission structure a durational component to its incentives? For example, should the Commission provide that transmission incentives automatically sunset after a certain period?*

As explained above, State Agencies believe that the Commission should phase out the existing ROE adder for transmission owners that already participate in an RTO. When new participants join an RTO, they should receive the ROE adder (provided they have not been a member of an RTO before)—but the adder should be available only for a limited time.

Project-specific ROE adders should be time limited too. Transmission facilities are very long-lived assets. Service lives exceeding 40 years are not uncommon. *See Pac. Gas & Elec. Co.*, Op. No. 470, 106 FERC ¶ 61,242, PP 7, 30-31 (2004). Transmission costs therefore remain in rate base for a very long time—well after the risks and challenges of developing and constructing a facility have been overcome, and well beyond the end of any reasonable planning period during which a project's net benefits might have been estimated.[38] State Agencies submit that there is no reason for customers to continue paying bonus ROEs for decades after the facts that originally justified the incentive have ceased to be operative.

Q 85) *Should the Commission provide that a transmission incentive can be eliminated or modified upon a material change to the transmission project? How would such an elimination or modification be implemented? What should constitute such a material change? How would the Commission and interested parties be informed of such a material change?*

Q 86) *Should there be a process of measurement and verification (or audit) to determine if the expected benefits accrued to consumers?*

Q 87) *If so, how should measurement and verification take place and over what time period?*

Q 88) *Should the Commission consider eliminating an incentive if the project fails to realize its anticipated benefits?*

Q 89) *Should there be reporting on projects' expected benefits compared to results, and over what time period?*

For similar reasons, the Commission should revisit any incentives it has granted if the facts that originally justified the incentives change in material ways. And it should do

[38] As noted above, State Agencies do not support granting ROE adders on the basis of anticipated project benefits. But if the Commission adopts that approach, it should impose time limits on the duration of any granted adders.

so no matter which framework it chooses for evaluating incentives initially—that is, regardless of whether the relevant facts are project characteristics, projected benefits, or risks and challenges. The Commission should require incentive applicants to identify with specificity the facts that they claim justify the incentive and to propose metrics for measuring any claimed benefits (assuming they are the basis for granting the incentive). If the Commission grants the incentive, it should impose on the recipient a continuing obligation to make an informational filing with the Commission reporting the materially changed circumstances. If facts change enough to render the incentive no longer just and reasonable, the Commission should terminate the incentive on its own motion or upon complaint.

2. Case-by-case vs. automatic approach in reviewing incentive applications

Q 90) *What are the benefits and drawbacks of granting incentives on a case-by-case basis, as compared to being granted automatically, with or without related threshold criteria? Would an automatic approach based on established threshold criteria provide additional certainty? If so, how?*

Q 91) *If so, how could the Commission determine which incentives should be awarded automatically?*

Q 92) *If the existing case-by-case approach to incentives is retained, could it be improved? If so, how?*

As explained above, State Agencies support case-by-case assessment of the need for incentives. While that approach entails up-front costs to prepare, support, and evaluate incentive applications, it should result in more tailored incentives that respond more directly and cost-effectively to actual (i.e., demonstrated) needs. We believe the savings more than justifies the up-front expense.

3. Interaction between different potential incentives in determining correct level of ROE incentives

The NOI acknowledges that, to date, the Commission "has provided limited guidance regarding what level of transmission incentives should be provided or how to ensure that the combination of transmission incentives provided is appropriate and produces rates that are just and reasonable." NOI P 46. It asks:

Q 93) *Should the Commission establish a more formulaic framework for determining the appropriate level and combination of incentives? If such a framework is created, what elements should it include?*

Q 94) *Alternatively, if the Commission continues evaluating incentive requests on a case-by-case basis, how could the Commission provide more detailed explanations in individual cases to better describe how it derives the appropriate level and combination of incentives? If so, what elements should such explanations provide?*

We understand these questions to focus on how the Commission sets the level of an ROE adder once the Commission decides to grant that incentive, either alone or in combination with risk-reducing incentives. We submit that there is no good answer to the question. In contrast to base ROE determinations, where there is an analytical framework to estimate an appropriate ROE corresponding to a company's overall risk, determining the magnitude of an ROE *adder* has been—and may intrinsically be—an arbitrary exercise. That is one reason why State Agencies disfavor ROE adders, when the Commission has better tailored, more precise tools. These include risk-reducing incentives, strengthened transmission planning protocols, and reforms to spur more competition in transmission planning and development. If competition is enhanced, responses to requests for proposals may provide useful information as to the nature and amount of ROE adders needed (if any) for the particular project. But, absent competitive bidding, State Agencies are aware of no meaningful way to determine the amount of ROE adder that is "needed and no more than is needed" (*City of Detroit v. FPC*, 230 F.2d at 817) to induce a transmission owner to overcome a project's risks and challenges.

4. Bounds on ROE incentives

Q 95) *The Commission's current policy is that the total ROE may not exceed the zone of reasonableness. If a transmission project qualifies for ROE incentives, should there be an upper limit or range that the total ROE cannot exceed? If so, what is the appropriate limit or range? Should this vary based on how the Commission sets base ROE?*

Total ROE, including any ROE adder, must remain capped at the upper end of the zone of reasonableness, because that boundary limits the extent to which ROE adders over-compensate transmission owners. As noted above, base ROEs for a company or proxy reflects the overall risk of *all* of the company's activities, including its low-, medium-, and higher-risk transmission projects. It over-compensates a transmission owner to apply the blended, base ROE only to low- and medium-risk projects and a higher, adder-enhanced ROE to higher-risk projects.[39] Bounding total ROE at the upper end of the zone of reasonableness does not fix this problem, but helps to limit the overcompensation.

H. The Commission should adopt and maintain metrics for determining the effectiveness of transmission incentives.

The NOI acknowledges that "it can sometimes be difficult to identify the extent to which a particular incentive motivates a transmission developer to take a particular action." NOI P 48. FERC asks what metrics it could use to measure the effectiveness of granted incentives to induce the desired conduct. Specifically it asks:

[39] As explained above, ROE adders should be reserved for projects that are so exceptionally risky (yet still net beneficial), even with risk-reducing incentives, that comparable companies have not undertaken them.

Q 98) *What metrics should the Commission use in measuring the effectiveness of incentives, e.g., if certain milestones are reached or only if a transmission project is built and energized?*

Q 99) *Should the obligation to file Form FERC-730 be expanded to all public utility transmission providers?*

Q 100) *Should the Commission require that incentive recipients provide additional data through Form FERC-730? If so, what additional information should be provided?*

Q 101) *For each transmission project, should the Commission require additional data such as the primary driver of each transmission project (e.g., reliability needs) and the risks entailed in its development (e.g., number of permits required, siting challenges)?*

Q 102) *If a transmission project is abandoned, should the Commission require additional data such as the reasons that it failed (e.g., lack of financing, inability to obtain permits, the need for the transmission project did not materialize or was addressed through other means)?*

Q 103) *Should the information on annual transmission spending associated with projects that received transmission incentives be broken down by transmission project?*

Q 104) *How burdensome would such information requirements be? To ensure that any reporting is not unduly burdensome, should the Commission adopt some type of reporting threshold, such as a voltage, mileage, or dollar threshold, to limit the transmission projects on which it collects information?*

Q 105) *Should the Commission upgrade the FERC-730 filing format to XBRL or another format or standard? If so, what filing format would be most beneficial and useful to filers and users of the information?*

State Agencies commend the Commission for asking how it can better track and evaluate the effectiveness of its transmission incentives policy. State Agencies request that Commission Staff maintain a publicly-available database of transmission projects for which incentives have been sought, including pertinent details about the project, projected costs, claimed benefits, claimed risks and challenges, which incentives were sought, and which were granted. The Commission should require transmission incentive applicants to set out these data in structured form in a separate section of their applications, cross-referencing other sections and pages as appropriate. When the Commission grants one or more incentives, it should specify the particular facts on which the award is based. Thereafter, as noted above, the applicant should be obliged to report to the Commission any material change to the factual premises for whichever incentives have been granted. Additionally, if a project is canceled or abandoned, the applicant or the relevant RTO should so report to the Commission and should explain the reason(s) for the cancelation or abandonment.

Respectfully submitted,

CONNECTICUT DEPARTMENT OF ENERGY AND ENVIRONMENTAL PROTECTION

/s/ Robert Snook

Robert Snook
Assistant Attorney General
Kirsten S. P. Rigney
Legal Director, Bureau of Energy Technology Policy
10 Franklin Square
New Britain, CT 06051
(860) 827-2657

CONNECTICUT PUBLIC UTILITIES REGULATORY AUTHORITY

/s/ Scott H. Strauss

Scott H. Strauss
Jeffrey A. Schwarz
Spiegel & McDiarmid LLP
1875 I Street NW, Suite 700
Washington, DC 20006
(202) 879-4000

Seth Hollander
Assistant Attorney General
Robert Luysterborghs
Principal Attorney
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051
(860) 827-2681

WILLIAM TONG, ATTORNEY GENERAL OF THE STATE OF CONNECTICUT

/s/ John S. Wright

John S. Wright
Lauren H. Bidra
Assistant Attorneys General
Attorney General's Office
10 Franklin Square
New Britain, CT 06051
(860) 827-2620

CONNECTICUT OFFICE OF CONSUMER COUNSEL

/s/ Elin Swanson Katz

Elin Swanson Katz, Esq.,
Consumer Counsel
Joseph A. Rosenthal, Esq.
Ten Franklin Square
New Britain, CT 06051
(860) 827-2900

ATTORNEY GENERAL OF THE
COMMONWEALTH OF
MASSACHUSETTS, MAURA
HEALEY

/s/ Donald W. Boecke

Rebecca Tepper
Donald W. Boecke
Assistant Attorneys General
Massachusetts Attorney General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, MA 02108
(617) 727-2200

June 26, 2019

Document Content(s)