DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM20–10–000]

Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission proposes to revise its existing regulations that implemented section 219 of the Federal Power Act in light of the changes in transmission development and planning over the last few years.

DATES: Comments are due July 1, 2020.

ADDRESSES: Comments, identified by docket number, may be filed electronically at *http://www.ferc.gov* in acceptable native applications and print-to-PDF, but not in scanned or picture format. For those unable to file electronically, comments may be filed by mail or hand-delivery to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. The Comment Procedures Section of this document contains more detailed filing procedures.

FOR FURTHER INFORMATION CONTACT:

David Tobenkin (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–6445, *david.tobenkin@ferc.gov*

Adam Batenhorst (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–6150, *adam.batenhorst@ferc.gov*

Adam Pollock (Technical Information), Office of Energy Market Regulation, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–8458, *adam.pollock@ferc.gov*

SUPPLEMENTARY INFORMATION:

Table of Contents

I. Introduction

1. In this notice of proposed rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) proposes to revise its existing transmission incentives policy and corresponding regulations (Transmission Incentives Regulations) [1] in light of changes in transmission development and planning in the last few years. After the enactment of the Energy Policy Act of 2005,[2] which added section 219 to the Federal Power Act (FPA),[3] the Commission promulgated Order No. 679 [4] pursuant to FPA section 219.

2. After Order No. 679, the Commission last reviewed its transmission incentives policy in its 2012 Policy Statement.[5] Even since then, the energy industry has undergone a transformation. The landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably. Those changes include an evolution in the resource mix and an increase in the number of new resources seeking transmission service, shifts in load patterns, the impact of the implementation of the Commission's major rulemaking on transmission planning and cost allocation (Order No. 1000),[6] and new challenges to maintaining the reliability of transmission infrastructure. As a result of these changes and the Commission's greater experience evaluating transmission incentive applications made pursuant to Order No. 679 and their relationship to the objectives of FPA section 219, we now propose to revise our transmission incentives policy to more closely align it with the statutory language of FPA section 219.

3. First, we propose to depart from the risks and challenges approach used to evaluate requests for transmission incentives adopted in Order No. 679 and instead focus on granting incentives based on the benefits to consumers of transmission infrastructure investment identified by Congress in FPA section 219: Ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. As described in the next two paragraphs, a

4. Second, we propose to offer public utilities an ROE incentive for transmission projects that provide sufficient economic benefits, as measured by the degree to which such benefits exceed related transmission project costs. Specifically, we propose to offer 50 basis points of ROE incentives for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period. We propose to offer 50 additional basis points of ROE incentives for transmission projects that demonstrate ex-post cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.

5. Third, we propose to offer public utilities an ROE incentive for transmission projects that provide significant and demonstrable reliability benefits. Specifically, we propose to offer up to 50 basis points of ROE incentives for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis. Cybersecurity is an important part of reliability and we will address cybersecurity incentives independently in a separate, future proceeding.

6. Fourth, we propose to modify the incentive allowing public utilities to recover 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors that are beyond the control of the applicant (Abandoned Plant Incentive). Specifically, we propose to allow public utilities with transmission projects that are selected in a regional transmission planning process for the purposes of cost allocation to recover 100 percent of abandoned plant costs from the date that such transmission projects are selected in a regional transmission planning process for the purposes of cost allocation, rather than from the date the Commission issues an order granting such recovery.

7. Fifth, we propose to revise our regulations to eliminate the ROE incentive and related acquisition adjustment incentive available to stand-alone transmission companies (Transcos).[7]

8. Sixth, consistent with the statutory language in FPA section 219, we propose to modify the ROE incentive available to transmitting utilities or electric utilities that join and/or continue to be a member of an Independent System Operator (ISO), Regional Transmission Organization (RTO), or other Commission approved Transmission Organization [8] (RTO-Participation Incentive) so that it is available regardless of whether the transmitting utility's or electric utility's participation in the ISO, RTO, or Transmission Organization is voluntary. The proposed RTO-Participation Incentive will be a uniform 100-basis-point increase to ROE for transmitting utilities that turn over their wholesale facilities to the Transmission Organization.

9. Seventh, we propose to offer public utilities incentives for transmission technologies that, as deployed in certain circumstances, enhance reliability, efficiency, and capacity, and improve the operation of new or existing transmission facilities. We propose that these technologies will be eligible for both: (1) A stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project; and (2) specialized regulatory asset treatment. Further, we propose to give pilot programs a rebuttable presumption of eligibility for these incentives.

10. Eighth, we propose to establish a 250-basis-point cap on total ROE incentives granted to a public utility in place of the current policy of limiting ROE incentives to the public utility's zone of reasonableness.

11. Ninth, we propose to reform the information collected from transmission incentive applicants in FERC–730, Report of Transmission Investment Activity (Form 730), by obtaining this information on a project-by-project basis and to expand some of the information collected.[9] We also propose to update the data reporting process.

[1] 18 CFR 35.35.

[2] Energy Policy Act of 2005, Public Law 109–58, sec. 1241, 119 Stat. 594 (2005).

[3] 16 U.S.C. 824s.

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

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

[6] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g,* Order No. 1000–A, 139 FERC ¶ 61,132, *order on reh'g and clarification,* Order No. 1000–B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC,* 762 F.3d 41 (D.C. Cir. 2014).

[7] The Commission defines a Transco as a stand-alone transmission company that has been approved by the Commission and that sells transmission service at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility. 18 CFR 35.35(b)(1); Order No. 679, 116 FERC ¶ 61,057 at P 201.

[8] A Transmission Organization is defined as an RTO, ISO, independent transmission provider, or other organization finally approved by the Commission for the operation of transmission facilities. 16 U.S.C. 796(29); 18 CFR 35.35(b)(2). The Commission is proposing to move the definition of Transmission Organization from § 35.35(b)(2) of its regulations to § 35.35(f) of the revised Transmission Incentives Regulations.

[9] Concurrent with this NOPR, the Commission is issuing an instant final rule clarifying the filing instructions for the current Form 730 at the request

Continued

II. Background

A. FPA Section 219

12. Prior to 2005, the Commission considered requests for certain transmission incentives pursuant to FPA section 205.[10] In 2005, Congress amended the FPA to, as relevant here, add a new section 219.[11] FPA section 219(a) directed the Commission to promulgate a rule providing incentive-based rates for electric transmission for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. FPA section 219(b) included a number of specific directives in the required rulemaking, including that the rule shall:

- Promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities; [12]
- Provide a return on equity that attracts new investment in transmission facilities, including related transmission technologies; [13]
- Encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; [14] and
- Allow the recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to FPA section 215,[15] and all prudently incurred costs related to transmission infrastructure development pursuant to FPA section 216.[16]

13. FPA section 219(c) states that the Commission shall, to the extent within its jurisdiction, provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization and ensure that any costs recoverable pursuant to this subsection may be recovered by such transmitting utility or electric utility through the transmission rates charged by such transmitting utility or electric utility or through the transmission rates charged by the Transmission Organization that provides transmission service to such transmitting utility or electric utility.[17]

14. Finally, FPA section 219(d) provides that rates approved pursuant to a rulemaking adopted pursuant to section 219 are subject to the requirements in FPA sections 205 and 206 [18] that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential.

B. Order Nos. 679 and 679–A

15. On July 20, 2006, the Commission issued Order No. 679, adding § 35.35 to the Commission's regulations to implement transmission incentives, and thereby fulfilling the rulemaking requirement in FPA section 219(a). The Commission explained that, to receive an incentive, an applicant must satisfy the statutory threshold set forth in FPA section 219(a) by demonstrating that the transmission facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. If the applicant satisfies that threshold, it must then demonstrate that there is a nexus between the incentive sought and the investment being made. The Commission stated that it would apply the FPA section 219(a) threshold and the nexus test on a case-by-case basis.[19]

16. The Commission also described a variety of incentives that would potentially be available, including:

- Increases above the base ROE: (1) To compensate for the risks and challenges of a specific transmission project (ROE incentive for risks and challenges); (2) for forming a Transco (Transco ROE Incentive); (3) for joining a RTO or ISO (RTO-Participation Incentive); or (4) for use of an advanced transmission technology;
- The Abandoned Plant Incentive, which is, as explained above, the ability to request 100 percent of prudently incurred costs associated with abandoned transmission projects to be included in transmission rates if such abandonment is outside the applicant's control;
- Inclusion of 100 percent of construction work in progress in rate base (CWIP Incentive);
- Hypothetical capital structures;
- Accelerated depreciation for rate recovery; and
- Recovery of prudently incurred pre-commercial operations costs as an expense or through a regulatory asset (Regulatory Asset Incentive).

17. On December 22, 2006, in Order No. 679–A, the Commission granted rehearing in part and denied rehearing in part of Order No. 679.[20] The Commission largely affirmed the conclusions discussed in the previous paragraphs while refining certain other aspects of Order No. 679. In its subsequent discussion of the nexus test, the Commission reaffirmed that the ''most compelling'' candidates for incentives are ''new projects that present special risks or challenges, not routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service.'' [21]

C. Order No. 1000

18. In 2011, the Commission issued Order No. 1000, which instituted certain transmission planning and cost allocation reforms for public utility transmission providers.[22] Notably, Order No. 1000 requires: (1) That each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan; (2) that local and regional transmission planning processes must provide an opportunity to identify and evaluate transmission needs driven by public policy requirements established by state or federal laws or regulations; (3) improved coordination between neighboring transmission planning regions for new interregional transmission facilities; and (4) the removal from Commission-approved tariffs and agreements of a federal right of first refusal.[23]

19. Order No. 1000 also requires that each public utility transmission provider must participate in a regional transmission planning process that has: (1) A regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation; and (2) an interregional cost allocation method for the cost of new transmission facilities that are located in two neighboring transmission planning regions and are jointly evaluated by the two regions in the interregional transmission coordination process.[24]

of the Office of Management and Budget (OMB). *Reporting of Transmission Investments,* Order No. 869, 170 FERC ¶ 61,219 (2020). Those changes are reflected into the Form 730 as proposed in this NOPR.

[10] 16 U.S.C. 824d; *see also Me. Pub. Utils. Comm'n* v. *FERC,* 454 F.3d 278, 287 (D.C. Cir. 2006).

[11] Energy Policy Act of 2005, Pub. L. 109–58, sec. 1241.

[12] 16 U.S.C. 824s(b)(1).

[13] *Id.* at 824s(b)(2).

[14] *Id.* at 824s(b)(3).

[15] FPA section 215 addresses the Commission's role in ensuring electric reliability of the bulk power system. *Id.* at 824o.

[16] *Id.* at 824s(b)(4). FPA section 216 addresses designation of and siting of transmission facilities within National Interest Electric Transmission Corridors. *Id.* at 824p.

[17] *Id.* at 824s(c).

[18] *Id.* at 824e.

[19] Order No. 679, 116 FERC ¶ 61,057 at PP 22, 24.

[20] Order No. 679–A, 117 FERC ¶ 61,345 at P 1.

[21] *Id.* PP 23, 60.

[22] Order No. 1000, 136 FERC ¶ 61,051.

[23] *See* Order No. 1000–A, 139 FERC ¶ 61,132 at P 1.

[24] Order No. 1000, 136 FERC ¶ 61,051 at P 9.

Although Order No. 1000 does not directly address the Commission's obligations under FPA section 219, the aforementioned reforms have had certain implications for how regional transmission facilities are planned and developed.

D. 2012 Policy Statement

20. On November 15, 2012, the Commission issued a policy statement to provide additional guidance regarding its evaluation of applications for transmission incentives under FPA section 219 and Order No. 679. In particular, the Commission reframed the nexus test for applicants seeking the ROE incentive for risks and challenges and eliminated the stand-alone advanced transmission technology incentive.[25] The Commission stated that it would expect an applicant seeking an ROE incentive for risks and challenges to demonstrate that: (1) The proposed transmission project faces risks and challenges that were not either already accounted for in the applicant's base ROE or addressed through non-ROE incentives; (2) it is taking appropriate steps and using appropriate mechanisms to minimize its risk during transmission project development; (3) alternatives to the transmission project had been, or would be, considered in either a relevant transmission planning process or another appropriate forum; and (4) it commits to limiting the application of the ROE incentive to a cost estimate.[26]

21. The Commission provided several examples of categories of transmission projects that might satisfy the above-noted ''risks and challenges'' expectation, including transmission projects that would: (1) Relieve chronic or severe grid congestion that has had demonstrated cost impacts to consumers; (2) unlock location-constrained generation resources that previously had limited or no access to the wholesale electricity markets; or (3) apply new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities.[27]

E. 2019 Notice of Inquiry

22. On March 21, 2019, the Commission issued a Notice of Inquiry seeking comment on the scope and implementation of its electric transmission incentives regulations and policy.[28] The 2019 Notice of Inquiry presented numerous questions regarding the Commission's approach to, and objectives of, its incentives policy; the mechanics and implementation of an incentives policy; and metrics for evaluating the effectiveness of incentives. The Commission received 67 initial comments and 47 reply comments.

F. Grid-Enhancing Technologies Workshop

23. On November 5 and 6, 2019, Commission staff led a workshop on grid-enhancing technologies (Grid-Enhancing Technologies Workshop).[29] Grid-Enhancing Technologies Workshop speakers identified several grid-enhancing technologies, including power flow control, transmission topology optimization, advanced line rating management, and storage as transmission. Speakers also discussed several methods to incentivize the deployment and implementation of grid-enhancing technologies, including a shared-savings approach. The Commission also issued a post-workshop notice seeking comment and received 19 comments.

III. Need for Reform

24. The reforms proposed to the Commission's transmission incentives policy will both help to reflect recent changes in the industry and transmission planning and more closely align with the statutory language of FPA section 219.

25. As part of ensuring that we continue to meet our statutory obligations, the Commission periodically reviews its existing policies and regulations. The Commission established its transmission incentives policy in Order No. 679 and clarified that policy six years later in the 2012 Policy Statement. In the nearly eight years since our last formal review of the Commission's transmission incentives policy, the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably. These changes include an evolution in the resource mix, an increase in the number of new resources seeking transmission service, shifts in load patterns, the Commission's implementation of Order No. 1000's reforms, and new challenges to maintaining the reliability of transmission infrastructure.

26. While transmission infrastructure development has remained generally robust at an aggregate level, the types of transmission projects that are needed, and the use of rate treatments to incent them, must evolve to reflect the changes in market fundamentals.

27. First, the nation's resource mix has evolved since the Commission's issuance of Order No. 679 in 2006, with rising use of natural gas and renewable resources and declining use of coal. In 2006, coal, natural gas, and nuclear made up nearly 88 percent of net electric generation in the United States, with coal contributing nearly 50 percent of total generation and natural gas contributing 20 percent of total generation, respectively.[30] By 2018, coal, natural gas, and nuclear still accounted for 82 percent of net electric generation; 27 percent of total generation was from coal and 36 percent from natural gas, respectively. Solar and wind increased from a collective one percent in 2006 to eight percent in 2018. These shifts create a need for more transmission infrastructure to bring generation to load. A survey of Edison Electric Institute (EEI) members shows that the need to integrate renewables and natural gas is one of the main drivers for expansion of the transmission system, as noted by U.S. Energy Information Administration (EIA).[31]

28. In addition to the changing mix of resources used to generate electricity, more types of resources are now participating in Commission-jurisdictional markets. Industry innovation and market reforms, demand-side resources, electric storage, distributed energy resources, and new technological innovations provide transmission operators with new opportunities as well as new challenges. There is a need for existing and new transmission facilities to help facilitate integration of these resources and a need to incent development and enhancement of transmission facilities so that they are effective in doing so.

29. Changes in load patterns are also driving new types of transmission investment. Despite low overall demand

[25] The Commission stated that, with respect to possible ROE incentives, it would prospectively consider advanced technologies only as part of an application for an ROE adder for risks and challenges. 2012 Policy Statement, 141 FERC ¶ 61,129 at P 23.

[26] *Id.* PP 20–28.

[27] *Id.* P 21. The Commission noted these examples of types of transmission projects that might qualify for an ROE adder for risks and challenges was not an exhaustive list. *Id.* P 22.

[28] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy,* 84 FR 11759 (Mar. 28, 2019), 166 FERC 61,208 (2019) (2019 Notice of Inquiry).

[29] FERC, *Grid-Enhancing Technologies,* Notice of Workshop, Docket No. AD19–19–000 (Sept. 9, 2019).

[30] In 2006, coal represented 49 percent, natural gas 20 percent, and nuclear power 19 percent of net electric generation in the United States. U.S. Energy Info. Admin., *Total Energy Annual Energy Review, Electricity Net Generation: Total (All Sectors),* at 1 (January 2020), *https://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf.*

[31] U.S. Energy Info. Admin., *Today in Energy* (Feb. 9, 2018), *https://www.eia.gov/todayinenergy/detail.php?id=34892.*

growth, electrification in industries such as transportation, heating, and agriculture are expected to contribute to peak load growth, requiring additional transmission investment to meet those needs.[32] Other shifts in load patterns are triggering targeted transmission investment, such as by Public Service Enterprise Group to meet urban area growth in Newark and Jersey City, New Jersey, or by Dominion Energy to meet the increased load needs of data centers in northern Virginia.[33] Another example of transmission being built to meet these various needs is the Energy Gateway Project, which EIA notes is being built to meet new demand patterns and provide greater access to new resources.[34] The Commission's incentives policy must be effective in incenting transmission projects that reflect existing, and can adapt rapidly to future, shifts in load growth patterns.

30. Additionally, transmission planning has evolved significantly. The 2012 Policy Statement was issued less than one month after transmission planning regions submitted their first round of Order No. 1000 regional compliance filings. All transmission planning regions have now conducted at least two iterations of their regional transmission planning process, with some having conducted as many as seven.[35] As part of such processes, the six RTOs/ISOs use sophisticated software modeling to identify the relative benefits and costs of proposed new transmission projects premised upon transmission projects' economic benefits. There is now an opportunity for the Commission to leverage the RTOs/ISOs' efforts to better target incentives at transmission projects that demonstrate sufficient economic benefits, as measured by the degree to which such benefits exceed related transmission project costs.

[32] *See* Brattle Group, *The Coming Electrification of the North American Economy,* at 7–12, 16–21 (Feb. 28, 2019), *https://wiresgroup.com/wp-content/uploads/2019/03/Electrification_BrattleReport_WIRES_FINAL_03062019.pdf.*

[33] Edison Electric Institute, *Smarter Energy Infrastructure: The Critical Role and Value of Electric Transmission,* at 7 (Mar. 2019), *https://www.eei.org/issuesandpolicy/transmission/Documents/2018%20Smarter%20Energy%20Infrastructure%20The%20Critical%20Role%20and%20Value%20of%20Electric%20Transmission.pdf.*

[34] U.S. Energy Information Administration, *Today in Energy* (Feb. 9, 2018), *https://www.eia.gov/todayinenergy/detail.php?id=34892.*

[35] *See* California Independent System Operator, Inc., *Transmission Planning for a Reliable, Economic and Open Grid, http://www.caiso.com/planning/Pages/TransmissionPlanning/Default.aspx;* WestConnect, *Regional Planning, http://regplanning.westconnect.com/regional_planning.htm.*

31. FPA section 219(a) requires that the Commission provide incentive-based rates for electric transmission for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. While we are encouraged by the investment in transmission infrastructure to date, our evaluation of the Commission's incentives policy indicates that additional reform may be necessary to continue to satisfy our obligations under FPA section 219 in this new transmission planning landscape.

32. Further, in reviewing our incentives policy under Order No. 679, we have determined that our current policy may not fully accomplish the purposes of FPA section 219. Congress in FPA section 219 directed that the Commission shall establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities *for the purpose of benefitting consumers* by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[36] As discussed in more detail in the following section, we are proposing to revise our transmission incentives policy in order to more closely align with the statutory language and purpose of FPA section 219. By ensuring that our incentives policy better aligns with our statutory requirements, we aim to set clear expectations for how the Commission will analyze future applications for incentives treatment, as well as increased transparency for the regulated industry.

33. This analysis also should increase certainty for developers; better align incentives awarded with transmission project benefits and costs; increase the precision and transparency with which transmission project benefits are considered by the Commission; and increase the ability, over time, of the Commission to determine whether incentives are effective in spurring development of transmission projects with desirable benefits.

IV. Discussion

A. Shift From Risks and Challenges to Benefits

34. We propose to revise § 35.35 of the Transmission Incentives Regulations to incorporate a benefits test to receive transmission incentives and to remove the nexus test from § 35.35(c) of the currently effective regulations. FPA section 219(a) explicitly recognizes the benefits of transmission projects by directing that the Commission shall establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[37]

[36] 16 U.S.C. 824s(a) (emphasis added).

35. Order Nos. 679 and 679–A implemented the provisions of FPA section 219 and established a ''nexus test,'' which required that applicants demonstrate a connection between the total package of incentives sought and the proposed investment, in light of the risks and challenges facing a transmission project seeking incentives under FPA section 219.[38] However, FPA section 219 neither includes this standard nor requires the Commission to find that the transmission project would otherwise not occur without the incentive.[39] The inclusion of this standard has focused applicants and the Commission on the risks and challenges of a transmission project rather than the purpose and language of FPA section 219, which is to benefit consumers by ensuring reliability and reducing the costs of delivered power by reducing transmission congestion, and ensuring that rates remain just and reasonable.

36. Based on experience to date with the application of Order No. 679, and in recognition of the changing landscape in the energy industry, we believe that refocusing our incentives program to more closely align with the statutory directive of FPA section 219 will allow the Commission to better fulfill its mandate. We therefore propose to

[37] *Id.*

[38] The applicant must demonstrate that the transmission facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent the requirements of section 219, that the total package of incentives is tailored to address the risks and challenges faced by the applicant in undertaking the project, and that the resulting rates are just and reasonable. 18 CFR 35.35(d); *see also* Order No. 679, 116 FERC ¶ 61,057 at P 76.

[39] *See* Order No. 679, 116 FERC ¶ 61,057 at P 53 (stating that FPA section 219 provides a new directive to the Commission to permit greater incentives and does not on its face require an individual showing of need by incentive applicants)*; see also Conn. Dept. of Pub. Util. Control* v. *FERC,* 593 F.3d 30, 34 (D.C. Cir. 2010) (''nothing in the law or FERC's stated purpose required FERC to adduce evidence . . . 'that the adder would produce new transmission investment'''). When the Commission explained why it was not adopting a ''but for'' test in Order No. 679, it noted that the rule was ''based on a clear directive from Congress that does not require an applicant to show that it would not build the facilities but for the incentives.'' Order No. 679, 116 FERC ¶ 61,057 at P 48.

depart from the ''nexus test'' framework of Order No. 679, and instead focus our decision to grant incentives on the benefits to consumers of transmission infrastructure investment identified by Congress: ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Accordingly, we propose to revise § 35.35(c) of the proposed Transmission Incentives Regulations to remove the nexus test and to implement a benefits test.

37. As described in detail below, with respect to ROE incentives based upon transmission projects' economic and reliability benefits, we propose separate analyses to implement the revised § 35.35(c) of the Transmission Incentives Regulations, wherein an applicant must demonstrate that the incentives it seeks meet a specified benefit-to-costs threshold for an economic benefits showing or provide a significant and demonstrable reliability enhancement for a reliability benefits showing, with each of these showings determining eligibility for distinct ROE incentives. Consistent with Congressional directive in FPA section 219(d), all ROE incentives must be just and reasonable.

38. Although we propose a shift in the Commission's transmission incentive analysis to concentrate on the benefits presented by transmission investment, we propose to retain non-ROE incentives, including the abandoned plant incentive, CWIP Incentive, hypothetical capital structure, accelerated depreciation for rate recovery, and regulatory asset treatment.[40] These non-ROE incentives remain vital in facilitating the investment in and the development of transmission projects as they remove regulatory barriers and other impediments to investment. These incentives will continue to remain available to all transmission projects that meet the Commission's rebuttable presumptions for transmission projects that result from fair and open regional transmission planning, receive construction approval from an appropriate state commission or state siting authority, or otherwise demonstrate that they are needed to ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[41] We propose only incremental reforms to some of these non-ROE incentives.[42] We continue to see transmission project-specific ROE incentives, for which we will require additional demonstration of benefits, as a supplement to these non-ROE incentives, as discussed further below.

39. We do not propose to require applicants for a transmission project-specific ROE incentive based upon transmission projects' economic or reliability benefits to demonstrate that base ROE or non-ROE incentives are insufficient to adequately address the needs of these transmission projects before seeking an ROE incentive, as is currently required for the ROE incentive for risks and challenges, which we propose to eliminate as we shift to a benefits-based approach for ROE incentives.

40. Furthermore, we propose no changes to the procedural flexibility offered to applicants seeking incentives, including applicants' ability to seek expedited declaratory orders on incentive proposals before submitting a filing for approval under FPA section 205 for inclusion of the incentives in rates.

B. Incentive ROE Reforms

41. FPA section 219 directed the Commission to provide a framework for granting incentives based on the benefits to consumers of transmission infrastructure investment that ensured reliability and reduced the cost of delivered power by reducing transmission congestion. We continue to believe that it is necessary to offer incentives under FPA section 219 to ensure an ROE that attracts new investment in transmission facilities and continues investment in beneficial transmission facilities.[43] Accordingly, we propose to offer a series of transmission ROE incentives designed to ensure that returns on equity attract investment in transmission infrastructure that has high economic benefits to consumers through congestion relief or that enhances reliability.

1. ROE Incentives

a. ROE Incentive for Economic Benefits

42. FPA section 219(a) directs the Commission to establish incentive-based rate treatments to benefit consumers by reducing the cost of delivered power by reducing transmission congestion, section 219(b)(1) directs the Commission to promote reliable and economically efficient transmission, and section 219(b)(2) directs the Commission to provide an ROE that attracts new investment in transmission facilities.[44] Accordingly, we propose to revise § 35.35(d) of our regulations to allow applicants to seek ROE incentives for transmission projects that provide sufficient economic benefits, as measured by the degree to which such benefits exceed related transmission project costs, as described further below.

43. We propose to grant ROE incentives to economic transmission projects based on economic benefit-to-cost tests, including a 50-basis-point ROE incentive for transmission projects that meet an ex-ante benefit-to-cost threshold, described below, and 50 additional basis points for transmission projects that demonstrate on an ex-post basis that they are able to satisfy a higher benefit-to-cost threshold when constructed. Regional[45] or local[46] transmission projects may be eligible for this incentive.

b. Adoption of a Benefit-to-Cost Test

44. We propose to adopt a benefit-to-cost ratio to determine the eligibility of economic transmission projects for ROE incentives to attract new investment in transmission facilities in order to implement our proposed revisions to § 35.35(d) of the revised Transmission Incentives Regulations. We believe that this approach is consistent with both a benefits-based approach and industry practice, as explained in greater detail below. Several RTOs/ISOs request that the Commission not impose a benefits-based incentives approach that would duplicate or interfere with their transmission planning efforts, cause inefficient use of RTO/ISO staff time, or engender contention and potential litigation.[47] With these concerns in mind, we propose an approach to economic benefits-based incentives that we believe is relatively simple, transparent, and yet is efficient in relying upon RTOs/ISOs' analyses of the economic benefits of transmission projects.

45. In Order No. 679, the Commission stated that it would not require applicants for incentive-based rate

[40] 2012 Policy Statement, 141 FERC ¶ 61,129 at PP 11–14.

[41] *See* proposed 18 CFR 35.35(e).

[42] *See* section II.D.

[43] 16 U.S.C. 824s(b)(2).

[44] *Id.* at 824s(a)–(b)(2).

[45] A regional transmission facility is a transmission facility located entirely in one region. Order No. 1000, 136 FERC ¶ 61,051 at n. 374.

[46] A local transmission facility is a transmission facility located solely within a public utility transmission provider's retail distribution service territory or footprint that is not selected in the regional transmission plan for purposes of cost allocation. *Id.* at P 63.

[47] California Independent System Operator Corporation Comments, Docket No. PL19–3–000, at 10 (filed June 26, 2019); Grid-Enhancing Technologies Workshop Transcript Day Two, Docket No. AD19–19–0000, at 286, 288, 296, 316, 325, 327, 334 (filed Jan. 6, 2020).

treatments to provide benefit-to-cost analyses.[48] Explaining why it was not requiring such showings, the Commission listed as considerations: (1) The Commission's authority to consider non-cost factors in awarding incentives; (2) that Congress's enactment of FPA section 219 reflected its determination that incentives generally can spur transmission investment which will, in turn, provide the benefits of a robust transmission system; and (3) the Commission's intent to consider the justness and reasonableness of any proposal for incentive rate treatment in individual proceedings.[49]

46. However, we believe that shifting from a risks and challenges based paradigm to a benefits-based paradigm, where incentives reward the most beneficial rather than most challenging transmission projects, supports using benefit-to-cost ratios to award economic incentives. Many transmission planning regions, including RTOs/ISOs, already identify beneficial transmission solutions and the heightened benefit-to-cost ratio thresholds we adopt below will ensure that we are providing incentives to highly beneficial transmission projects. Specifically, in many RTOs/ISOs, competing economic transmission projects are evaluated through a comparison of transmission projects' economic benefits with their costs, generating benefit-to-cost ratios that evaluate transmission projects by their net benefits.[50] In addition, many applications requesting ROE incentives for risks and challenges already include some analysis of benefits and costs.[51]

47. The widespread use of benefit-to-cost ratios for evaluating economic transmission projects in RTO/ISO transmission planning regions demonstrates the reasonableness of employing benefit-to-cost ratios to determine whether transmission projects merit ROE incentives premised upon economic benefits. The use of benefit-to-cost ratios for awarding ROE incentives will allow the Commission to set a clear expectation as to the level of benefits relative to costs required to receive an ROE incentive. We request comment on the merits of the use of benefit-to-cost ratios to determine eligibility of transmission projects, regardless of the type of transmission project, for ROE incentives based on their economic benefits.

c. Benefit-to-Cost Measurements

48. In calculating the economic benefits of a transmission project for which a public utility is requesting ROE incentives, we propose to limit measurement of economic benefits to adjusted production costs or similar measures of congestion reduction or certain other quantifiable benefits that are verifiable and not duplicative. With respect to transmission projects' economic benefits, transmission planning regions typically evaluate the economic efficiency of transmission projects through production cost modeling. This analysis seeks to minimize total system cost by evaluating the security constrained unit commitment and economic dispatch of the system over a given time horizon within a transmission planning region. A transmission project, whether regional or local, is classified as ''economic'' if it reduces the total system cost by an amount that justifies its cost, usually by establishing net positive benefits, and sometimes surpassing a defined benefit-to-cost threshold. In RTO/ISO regions, all regional transmission projects selected in a regional transmission plan for purposes of cost allocation, and sometimes other transmission projects premised primarily on their economic benefits, are evaluated through production cost or similar modeling.[52] Some of the non-RTO/ISO regions' transmission planning processes also include production cost modeling.[53]

49. In addition, many regions supplement adjusted production cost models with other economic benefit metrics. MISO, for example, has also proposed to examine reliability transmission project costs avoided by the construction of an economic transmission project, as well as the impacts on congestion of a settlement between MISO and Southwest Power Pool, Inc. (SPP),[54] and already considers the relative degree to which an economic transmission project will solve a congestion problem. In this example, MISO might choose an economic transmission project that completely resolves congestion in a particular location on the system over a transmission project with a higher benefit-to-cost ratio that relieves only a portion of the congestion.[55] Similarly, PJM's process allows for a holistic assessment of benefits and considers factors, such as constructability analysis, effects of transmission project combinations, and changes in load energy payments, in its overall consideration of transmission projects.[56] California Independent System Operator Corporation (CAISO) assesses on a case-by-case basis other economic opportunities that are not necessarily driven by congestion. Such economic opportunities may include local capacity benefits (*e.g.,* reducing the requirement for local generation capacity due to limited transmission capacity into an area).[57] In NYISO, the economic transmission planning process uses production cost savings as the primary metric in its initial phase; subsequently, NYISO considers additional metrics on a case-by-case basis, depending on the most useful ones for each economic planning cycle.[58] Commenters in other

[48] Order No. 679, 116 FERC ¶ 61,057 at P 65.

[49] *Id.*

[50] *See, e.g.,* MISO, *MTEP18 Transmission Expansion Plan,* at 100 (Sep. 18, 2018), *https://cdn.misoenergy.org/MTEP18%20Full%20Report264900.pdf* (presenting a comparison of benefit-to-cost ratios for potential transmission project for MISO's Dakotas/Minnesota region); PJM Interconnection, LLC, *Transmission Expansion Advisory Committee Market Efficiency Update,* at 7 (Dec. 3, 2015), *https://www.pjm.com/-/media/committees-groups/committees/teac/20151203/20151203-market-efficiency-update.ashx* (describing the reliability pricing model benefit component of the benefit/cost ratio).

[51] For example, New York Independent System Operator, Inc. (NYISO) found that the Empire Project proposed by NEET New York is expected to result in: (1) Production cost savings on the NYISO system of approximately $274 million to $338 million over a 20-year period, adjusted on a present value basis to 2017 dollars; and (2) demand congestion change savings on the NYISO system of $582 to $1.184 billion over a 20-year period, adjusted on a present value basis to 2017 dollars. *NextEra Energy Transmission N.Y., Inc.,* 162 FERC ¶ 61,196, at P 21 (2018).

[52] *See, e.g.,* California Independent System Operator, Inc., *2018–2019 Transmission Plan,* at sec. 4.4 (Mar. 29, 2019); Midcontinent Independent System Operator, Inc., *MISO Adjusted Production Cost Calculation White Paper* (Feb. 1, 2019); PJM Manual 14B, *PJM Regional Transmission Planning Process* (Aug. 28, 2019); New York Independent System Operator, Inc., Manual 35, *Economic Planning Process Manual-Congestion Assessment and Resource Integration Studies,* sec. 2.5 (Feb. 2016).

[53] *See, e.g.,* Northern Tier Transmission Group, *2018–2019 Biennial Transmission Plan,* at 10 (Dec. 31, 2019); WestConnect Business Practice Manual, section 4.2.1.1.

[54] Midcontinent Indep. Sys. Operator, Inc., Filing, Docket No. ER20–857–000, at 4 (Jan. 21, 2020)).

[55] *See* MISO, *MTEP 2018: Transmission Expansion Plan,* at 100 (declining to move a transmission solution forward in the study cycle because, ''[a]lthough it shows a good benefit-to-cost ratio, it leaves a significant amount of the congestion unaddressed and the upgrade will most likely not be enough given the future wind development in the Dakotas and Minnesota border area'').

[56] PJM, *Market Efficiency Study Process and RTEP Window Project Evaluation Training,* at 21 (Oct. 16, 2018); PJM, *2017 Regional Transmission Expansion Plan: Book 3 Studies and Results,* at 69 (Feb. 28, 2018).

[57] Other benefits include renewable integration benefit, resource adequacy benefit, and transmission loss benefits. CAISO, *Transmission Economic Assessment Methodology,* sec. 2.5 Additional Benefits of Economically Driven Transmission Expansion (Nov. 2, 2017).

[58] These other metrics include: Estimates of reductions in losses, locational based marginal pricing load costs, generator payments, installed capacity costs, ancillary services costs, emission

proceedings have also identified other potential economic benefits.[59]

50. While most RTOs/ISOs employ other economic benefit metrics in addition to adjusted production cost, we propose to limit our analysis of economic benefits to adjusted production cost, similar measures of congestion reduction, and certain other quantifiable benefits that are verifiable and not duplicative.[60] Although excluding factors beyond adjusted production cost or similar measures of congestion reduction and quantifiable economic benefits will reduce the comprehensiveness of the measurement of economic benefits, we believe that this is a reasonable tradeoff in the interest of an economic benefits test that is transparent and relatively straightforward for applicants to prepare and for the Commission to analyze. We also propose to provide a rebuttable presumption that economic benefits measured in benefit-to-cost ratios derived by RTOs/ISOs for transmission projects within their footprints should be included in the determination of an applicant's transmission project's benefits. Additionally, we propose that the appropriate benefit-to-cost ratio for purposes of the ex-ante evaluation is measured at the time the RTO/ISO finalizes its analysis of potential economic transmission projects within its region.

51. Although we believe that the use of adjusted production cost, similar congestion reduction measurements, and other quantifiable benefits strikes a reasonable balance for the purpose analyzing economic benefits, we request comment on whether additional types of economic benefit measures should be considered for purposes of an economic benefit ROE incentive. We also request comment on existing methods that are equivalent (or comparable) to adjusted production cost that might inform the range of benefits measures that could be utilized.

52. Although some RTOs/ISOs appear to provide stakeholders access to the results of their adjusted production cost models, it is unclear whether all RTOs/ISOs provide public utilities with the results of their adjusted production cost models, similar congestion reduction measurements, or other quantifiable benefits as economic benefits measures, and the resulting benefit-to-cost ratios in a manner that would allow the developer to use these results to seek an ROE incentive for economic benefits. For example, some RTOs/ISOs may require stakeholders to execute a non-disclosure agreement to gain access to study results. In addition, some RTOs/ISOs conduct multiple economic simulations for transmission projects, and it is not clear if these regions perform a single, final adjusted production cost or equivalent economic analysis that would allow for apples-to-apples comparisons of transmission projects. Further, some RTOs/ISOs may not conduct studies of the economic benefits of all transmission projects. We invite further comment on current RTO/ISO practices with regard to the dissemination of production cost modeling information and the derivation of benefit-to-cost ratios and whether these practices could hamper an applicant from using the RTO/ISO modeling results to seek an ROE incentive for economic benefits.

53. In addition, we recognize that public utilities outside of RTOs/ISOs may face challenges in using their transmission planning region's existing processes for analyzing the economic benefits of transmission projects to produce benefit-to-cost analyses for use in an ROE incentive application. Given non-RTO/ISO regions' lack of centrally-cleared markets that allow them to determine how a new transmission facility will change production costs or the price that load must pay at wholesale for electricity, their economic analyses vary greatly from those that RTO/ISO transmission planning regions conduct. Some of the non-RTO/ISO transmission planning regions—WestConnect, ColumbiaGrid, Northern Tier Transmission Group, and Florida Reliability Coordinating Council (FRCC)—consider some form of economic benefits as part of their regional cost allocation methods. For example, under WestConnect's regional cost allocation method for regional transmission projects driven by economic considerations, WestConnect identifies the benefits and beneficiaries of a proposed regional transmission facility by modeling the potential of that transmission facility to support more economic, bilateral transactions between generators and loads in the region.[61] FRCC's process includes a cost-benefit ratio calculation for transmission projects in consideration in its regional transmission plan based on avoided project cost benefits, alternative project cost benefits, and transmission line loss benefits.[62] Whereas, in SERTP, the process mainly focuses on a power flow analysis, and includes such metrics as avoided costs of displaced transmission, and thermal and voltage constraints.[63] We invite comment on the availability and accessibility of adjusted production cost and similar economic benefit measurement data that applicants could use to analyze the economic benefits of a transmission project for purposes of seeking an ROE incentive in non-RTO/ISO regions. We also seek comment on any economic calculations that entities in non-RTO/ISO regions perform in their transmission planning processes (whether economic calculations from transmission planning regions or by public utilities), and the extent to which it might be feasible to calculate benefit-to-cost ratios for any transmission projects for which these transmission projects' developers might consider seeking an economic benefit incentive.

54. Applicants, either in RTOs/ISOs or non-RTO/ISO transmission planning regions, seeking such incentives may produce their own benefit-to-cost study of economic benefits for their transmission projects for consideration by the Commission. Such studies may be prepared by applicants, third party consultants or, if offered, by transmission planning regions. These studies should include quantitative and qualitative description and analysis, including description of any cost or benefit analysis for the transmission project by transmission planning regions or the applicant in transmission planning regions, and detailed analysis and supporting testimony for the applicant's calculation of the transmission project's economic benefits, including major model assumptions, costs, and the resulting benefit-to-cost ratio. However, such non-RTO/ISO-performed studies will not receive a presumption that they are appropriately included in a determination of economic benefits. We invite comment on what supporting information and analysis an applicant's benefit-to-cost study should include.

55. More generally, we also seek comment on how measurement of economic benefits can be distinguished from measurement of other types of benefits considered for purposes of

costs, and transmission congestion contract payments. NYISO, NYISO Tariffs, NYISO OATT, att. Y Economic Planning Process, sec. 31.3.1.3.5 (11.0.0).

[59] *See* Johannes Pfeifenberger and Judy Chang, Comments, Docket No. AD16–18–000 (filed Oct. 3, 2016) (attaching multiple reports on transmission planning and the benefits of the transmission system).

[60] These might include (but are not limited to): Types of load cost savings, capacity benefits, and avoided local transmission project costs.

[61] *See* WestConnect, WestConnect Regional Planning Process Business Practice Manual, sec. 4.6.1.2.

[62] *See* FRCC regional transmission planning process, sec. 7.2.2.

[63] *See,* for example, SERTP 2019 Transmission Planning Analyses, Part II.

other incentives so that double counting of benefits does not occur.

d. Establishing a Benefit-to-Cost Threshold for Economic Incentives

56. We believe that transmission projects should offer substantially more economic net benefits than the average transmission project to be eligible for an incentive premised upon economic benefits. We also believe that it is reasonable to analyze transmission projects by size based on the cost of the transmission project. Thus, we propose to use $25 million, adjusted annually for inflation,[64] as a reasonable dividing line between small system modifications and significant transmission facility expansions. We find that these two categories merit separate benefit-to-cost thresholds. We propose to implement procedures that will provide for inputting and calculation of new national benefit and cost data and the resulting benefit-to-cost threshold between small system modifications and significant transmission facility additions at five-year intervals.

57. As a first step toward developing national benefit-to-cost ratios, we examined 41 economic transmission projects selected in the regional transmission plans of MISO,[65] CAISO,[66] and PJM [67] from 2013 through 2019.[68] Of these transmission projects, 11 cost more than $25 million and, for these transmission projects, the average benefit-to-cost ratio was 3.63. To be eligible for an ex-ante economic benefits ROE incentive, we propose that transmission projects must demonstrate net benefit ratios consistent with the 75th percentile of all transmission projects more than $25 million in these regional plans over the study period, which was 3.98. We note that consideration of benefit-to-cost ratios in other transmission planning regions would help to further support the thresholds for an economic benefits ROE incentive and we propose to expand the derivation of percentile thresholds through examination of benefit-to-cost ratios in other regions, if available, in any final rule. We seek comment on combining different RTO/ISO benefits measurement methodologies as part of an effort to derive a national benefit-to-cost threshold and the merits and downsides to doing so. Further, we encourage additional RTOs/ISOs to provide benefit-to-cost information to make these threshold figures more robust. Finally, we request comment on whether the benefit-to-cost ratio threshold calculations for the transmission projects should include the costs of ROE incentives.

58. For transmission projects that cost less than or equal to $25 million, the average benefit-to-cost ratio for the 30 qualifying transmission projects in MISO, CAISO, and PJM was 26.67, and the ratio for the 75th percentile transmission project was 33.91, which we propose to use as the threshold for an ex-ante economic benefit ROE incentive for these transmission projects.

59. We also propose to offer an additional 50-basis-point incentive for economic benefits as measured on an ex-post basis. To be eligible for an ex-post economic benefits incentive, a transmission project must exhibit a benefit-to-cost ratio in the top 10 percent of transmission projects at the time of transmission project completion based on applying their actual costs to the projected benefits. Like the ex-ante economic benefit ROE incentive, a successful applicant would start earning this incentive in the rate year in which the transmission facility is placed in service. We considered using ex-post benefits versus projected benefits in this analysis, but concluded that the burden of determining and measuring such benefits, and the potentially significant amount of potential changes in transmission project benefits for reasons outside of the control of developers, makes such ex-post review inappropriate. By contrast, application of actual cost information is relatively uncontroversial and straight-forward. For the study period, the 90th percentile for all transmission projects in the three regions greater than $25 million would be 5.17, and 77.04 for transmission projects equal to or less than $25 million.

60. We believe that providing an opportunity for an additional, ex-post incentive for an applicant would benefit customers by further incentivizing transmission project developers to meet a transmission project's projected benefit-to-cost estimates by completing their transmission projects at or below projected costs. We seek comment on whether the Commission should exclude costs resulting from factors beyond a developer's control from the ex-post analysis for an ex-post economic benefits ROE incentive. However, regardless of cost overruns, an applicant would remain eligible for the ex-ante economic benefit ROE incentive. Given that these ratios are significantly above the average of transmission projects premised upon economic benefits, we believe that these incentives are directed to transmission projects that are more beneficial than the average transmission project.

61. To further explain the economic benefits ROE incentive, assuming, for example, that a transmission project has estimated benefits of $400 million, ex-ante estimated costs of $100 million and ex-post, final actual costs of $75 million, such a transmission project could earn up to 50 basis points for demonstrating the 3.98 ex-ante threshold ($400M/$100M=4.00) and up to an additional 50 basis points for achieving the 5.17 ex-post threshold ($400M/$75M=5.33) after the transmission project is completed. We seek comment on this approach and, more generally, on the manner in which these thresholds are calculated.

62. We propose to establish a construct for the determination of applicable benefit-to-cost thresholds that would also provide for reevaluation of these thresholds every five years based upon a reexamination of transmission projects selected in transmission planning regions based upon their economic benefits. We also propose to update for inflation the dividing line between small and large transmission projects for the purpose of determining the respective thresholds for these transmission projects annually.

2. Reliability Benefits

63. FPA section 219(a) directs the Commission to establish incentive-based rate treatments to benefit consumers by ensuring reliability and FPA section 219(b)(1) directs the Commission to promote reliable and economically efficient transmission.[69] Although reliability is clearly delineated as a benefit to be promoted by incentives, we are cognizant of our differing but related mandates for promoting reliability under FPA sections 215 and 219.

64. Pursuant to FPA section 215, the Commission has approved a set of mandatory reliability standards developed by the North American Electric Reliability Corporation (NERC).

[64] We also propose a $25 million threshold for incentives for pilot programs discussed in section IV.G.3.b.

[65] MISO transmission projects included projects selected based upon their economic benefits as market efficiency projects and other economic projects. Multi-Value Projects were excluded because MISO's benefit-to-cost ratios do not differentiate between economic, reliability, and public policy requirement benefits.

[66] CAISO transmission projects considered are those coming out of CAISO's economic planning study of its Transmission Planning Process.

[67] PJM transmission project types studied included those designated by PJM as Market Efficiency Projects.

[68] Specifically, CAISO from 2013–2019; MISO and PJM from 2015–2019. These analyses, based upon publicly available data, are available in Appendix A.

[69] 16 U.S.C. 824s(a)–(b)(1).

The NERC reliability standards define the reliability requirements for the planning and operation of the bulk power system, including transmission facility planning, emergency preparedness, voltage and balancing, and interconnection, among others. Transmission projects required to comply with these standards are assured recovery of all prudently incurred costs pursuant to FPA section 219(b)(4)(A).[70] In accordance with the aim of FPA section 215, the NERC reliability standards provide for an adequate level of reliability.[71] In light of these mandatory reliability standards, and the guaranteed cost recovery pursuant to FPA section 219(b)(4)(A), additional transmission incentives are not necessary to maintain an adequate level of reliability. Nevertheless, as explained below, we believe that a changing electric grid presents reliability challenges that merit increased capital investment in transmission facilities. We therefore propose in § 35.35(d)(1)(iii) of the revised Transmission Incentives Regulations to provide an ROE incentive for certain transmission projects that produce significant and demonstrable reliability benefits above and beyond the requirements of the NERC reliability standards.

a. Reliability Incentive Proposal

65. We propose in § 35.35(b)(1)(iii) of the revised Transmission Incentives Regulations to offer a separate ROE incentive of up to 50 basis points for transmission projects that provide significant and demonstrable reliability benefits. At the outset, we acknowledge that reliability benefits are often more difficult to quantify than economic benefits. Nevertheless, FPA section 219(a) directs the Commission to establish incentive-based rate treatments for the purpose of benefiting consumers by ensuring reliability. Accordingly, to better align our incentives policy with the goals of FPA section 219, we propose to adopt an approach that quantitatively evaluates the reliability benefits of proposed transmission projects when feasible, but also recognizes the value of qualitative assessments of enhanced reliability. We plan to offer reliability benefit ROE incentives for all types of transmission projects within the Commission's jurisdiction that can demonstrate the showing described below.

66. Reliability benefits can take many forms. A transmission project may provide one exceptional reliability benefit or a portfolio of several reliability benefits. Each transmission project has unique attributes, so we propose to evaluate the merits of an application for a reliability ROE incentive based on the transmission project providing one or more significant and demonstrable reliability enhancements. The Commission will evaluate each application on a case-by-case basis.

67. We propose a nonexclusive set of examples and demonstrations that could form the basis of a showing of significant and demonstrable reliability benefits that a transmission project could provide. We note that, as this is not an exclusive list, there may be transmission projects with other significant and demonstrable reliability benefits that warrant incentives. Accordingly, we invite comment on other types of reliability benefits in addition to those discussed below.

68. A transmission project may demonstrate reliability benefits in any number of ways. First, transmission projects that significantly increase import or export capability between balancing authorities can provide significant and demonstrable reliability benefits. For example, increasing import capability can provide access to additional generation capacity which could be necessary to prevent load shedding or restore load generation balance in an emergency. In addition, creating additional transmission capability on frequently constrained interfaces can reduce the likelihood of a System Operating Limit exceedance that can damage equipment and disrupt system operations.

69. Second, transmission projects that result in an Interconnection Reliability Operating Limit (IROL) being downgraded to a routine System Operating Limit likely produce significant and demonstrable reliability benefits. The NERC reliability standards define IROLs as a sub-set of system operating limits that are more likely to result in severe cascading, instability, or uncontrolled separation if violated. Pursuant to the NERC standards, there are no limits on the number of IROLs an entity can have in its footprint, and, in fact, registered entities are required to designate new IROLs where applicable criteria are met. Similarly, transmission projects that are likely to reduce the frequency and/or duration of IROL exceedances can also provide significant and demonstrable reliability benefits.

70. Third, transmission projects that improve the bulk power system's ability to operate reliably during foreseen and unforeseen contingencies beyond the NERC transmission planning (TPL) requirements or other local planning criteria, can provide significant and demonstrable reliability benefits. For example, an applicant may demonstrate that its proposed transmission project improves system stability margins on transfer paths or in generation or load pockets in its request for a reliability ROE incentive. We propose that an applicant may demonstrate this type of reliability benefit in a variety of ways, including by showing reduced loss of load probability, reduced need for reliability unit commitments, or by reducing unserved energy under various contingencies.

71. Fourth, transmission projects that reduce the complexity of the transmission system by eliminating the need for one or more remedial action schemes[72] on the system can provide significant and demonstrable reliability benefits. We propose that an applicant can demonstrate that its proposed transmission project ensures reliability by the elimination of complex remedial action schemes, which can in turn lower the risk of misoperations due to design errors, relay failures, or communication failures.

72. Finally, transmission projects that use network management technologies, such as dynamic line ratings, power flow controls, or transmission topology optimization, can provide significant and demonstrable reliability benefits by giving operators better tools to address unforeseen system conditions. While these investments may not be required to meet reliability standards, they can expand the event response capabilities of the transmission system by enhancing situational awareness and facilitating faster response times to mitigate system disturbances, thus improving reliability. Accordingly, we propose that an applicant may demonstrate enhanced reliability through deployment of these technologies. Although we are proposing specific incentives to facilitate investment in transmission technologies,[73] we also propose to consider the reliability benefits offered by including these technologies in transmission projects to the extent that these technologies add to or improve the reliability of a transmission project as a whole. A transmission project may offer reliability benefits both because of, and independent of, the inclusion of transmission technologies.

[70] *Id.* at 824s(b)(4)(A).

[71] *Id.* at 824o(a)(3).

[72] NERC defines a remedial action scheme as a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation, tripping load, or reconfiguring a system.

[73] *See infra* section IV.G.2.

73. In addition to the five examples of types of reliability transmission projects discussed above, which are likely to meet the Commission's test of providing significant and demonstrable reliability benefits, we encourage applicants to propose other transmission projects that they think provide significant and demonstrable reliability benefits. We recognize the importance of maintaining a transmission system that can withstand extreme environmental and other disruptive events and remain operational in the face of such challenges, which can vary based on geographic region and system topology. Accordingly, we will also consider transmission projects that improve resilience in awarding reliability incentives.[74] Transmission projects that provide resilience benefits in areas where they are needed could include the hardening of transmission assets against adverse weather events, fires, and geomagnetic disturbances, or event recovery investments such as transmission facilities related to blackstart facilities. Investments in transmission facilities for purposes of disaster recovery, such as transformers and circuit breakers, or other used and useful equipment for emergency response and recovery, also are potential investments that could be considered for a reliability incentive.

b. Proposed Showing and Commission Analysis

74. In order to provide incentives for increasing system reliability, we propose to award up to 50 basis points for a transmission project that provides one or more significant and demonstrable reliability benefits to address specific reliability needs. The reliability incentives will be added to the applicant's base ROE and will be subject to the 250-basis-point ROE incentives cap, as described below.[75] We propose that applicants should support their requests by providing a quantitative analysis of a transmission project's potential reliability benefits, where possible. Such analyses should include, for example, reduced loss of load probability, reduced unserved energy under various contingencies, reductions in reliability unit commitments, increases in import or export capability, and improvements in voltage stability. We would then review the potential reliability benefits to determine whether and how much of an ROE incentive the transmission project should be awarded. If an applicant is not able to provide a quantitative analysis, we also propose to consider qualitative demonstrations that a transmission project provides one or more significant and demonstrable reliability benefits to address specific reliability needs.

75. We seek comment as to whether there are different and/or additional elements that affect the reliability of the transmission system that we should consider in our analysis for reliability ROE incentives. If so, we request that commenters explain how a transmission project improves various elements of system reliability, how an applicant can demonstrate that a transmission project provides these benefits quantitatively or qualitatively in the absence of a quantitative analysis, and how we can measure or evaluate that demonstration.

C. Ensuring Reasonableness of ROE

76. In addition to ensuring an ROE that is sufficient to attract investment in transmission facilities, the Commission must also ensure that rates adopted under this policy remain just and reasonable and not unduly discriminatory or preferential under FPA sections 205 and 206.[76] In Order No. 679, the Commission required that any ROE incentives would be subject to the total ROE remaining within the zone of reasonableness and found that an ROE within the zone of reasonableness would be adequate to attract new investment.[77] Due to changing investment conditions, we propose to change the current policy of interpreting FPA section 219(d) to require that the ROE, inclusive of any incentives, remain within the zone of reasonableness. We propose to allow the ROE incentives to exceed the zone of reasonableness when added to the base ROE. However, we are proposing to modify § 35.35(b)(2) of the Transmission Incentives Regulations to cap ROE incentives, including incentives to attract new investment, for increasing reliability, for transmission technology investment, and for joining and remaining in a Transmission Organization, to a total of no more than 250 basis points, as explained further below. Consistent with Congressional directive in FPA section 219(d), all ROE incentives must be just and reasonable.

77. The Commission has previously recognized that its obligations under FPA sections 219 and 205 overlap in significant ways, and it may be difficult to meaningfully distinguish between an ROE that appropriately reflects a public utility's risk and an incentive ROE to attract new investment.[78] Nevertheless, the Commission is ''obligated to establish ROEs for public utilities that both reflect the financial and regulatory risks attendant to a particular transmission project and that are sufficient to actively promote capital investment.'' [79] Although the Commission previously harmonized these principles under the zone of reasonableness, we believe that a change in policy recognizing these differences is justified.

78. Our proposal recognizes that base ROE and transmission ROE incentives serve different functions. The Commission has found that base ''ROE 'should be commensurate with returns on investments in other enterprises having corresponding risks' and 'sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.' '' [80] This is different from FPA section 219(b)(2), which provides that the Commission should offer a return on equity that attracts new investment in transmission facilities (including related transmission technologies). The Commission has explained that, ''[i]n contrast to a base-level ROE that reflects the financial and regulatory risks of an investment, an 'incentive' has been more typically associated with specific basis point additions to a base ROE to satisfy discrete policy objectives.'' [81] Therefore, the returns provided by base ROE serve a different purpose than the separate grant of authority in FPA section 219(b)(2) to provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies). We find that the different purpose for an incentive ROE adder than for a base ROE provides that ROE incentives may be just and reasonable under different circumstances than base ROEs. Therefore, ROE incentives may meet a different test for just and reasonable

[74] *See Grid Reliability and Resilience Pricing and Grid Resilience in Regional Transmission Organizations and Independent System Operators,* 162 FERC ¶ 61,012, at P 23 (2018) (proposing to define ''resilience'' as ''the ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event'').

[75] *See infra* section IV.C.

[76] 16 U.S.C. 824s(d).

[77] Order No. 679, 116 FERC ¶ 61,057 at PP 2, 91–93. The Commission assembles and uses the zone of reasonableness in its evaluation of the justness and reasonableness of public utility ROEs in order to balance the interests of investors and consumers. *See Emera Maine* v. *FERC,* 854 F.3d 9, 20–21 (DC Cir. 2017) (*Emera Maine*).

[78] Order No. 679–A, 117 FERC ¶ 61,345 at P 15.

[79] *Id.*

[80] *Emera Maine,* 854 F.3d at 20 (citing *FPC* v. *Hope Nat. Gas Co.,* 320 U.S. 591, 603 (1944); *Bluefield Waterworks & Improvement Co.* v. *Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679, 692–93 (1923)).

[81] Order No. 679–A, 117 FERC ¶ 61,345 at n.19.

rates than for a base ROE, and ROE incentives that are added to the base ROE are, therefore, not required to be bound by the zone of reasonableness in order to be just and reasonable and not unduly discriminatory.

79. In Order No. 679, the Commission found that allowing ROE incentives up to the upper end of the zone of reasonableness was consistent with FPA section 205 and was ''adequate to attract new investment and consistent with the intent of Congress in FPA section 219.'' [82] Nevertheless, given the Commission's experience with the transmission incentives policy under FPA section 219, we believe that this existing limit on ROE incentives may no longer be adequate to attract new investment in transmission facilities, as required by FPA section 219. For example, the traditional starting point for analyzing the base ROEs of a group of utilities with above average risk is the upper midpoint of the zone of reasonableness, but, if the Commission were to retain ROE incentive limits based on the upper end of the zone of reasonableness, the proximity of the base ROEs of such average utilities to that upper end may prevent them from receiving the incentives granted by the Commission under FPA section 219 in order to provide a rate of return that attracts new investment. Limiting ROE incentives to the zone of reasonableness may undermine the Commission's ability to recognize and address the separate need to attract new investment and exposes transmission investment receiving incentive rates to the additional risk that changes to the public utility's risk profile may lower the incentives granted by the Commission. We do not believe it was the intent of Congress to preclude utilities with above-average risk profiles from receiving ROE incentives. Therefore, we propose to remove this restriction and recognize that rates outside the zone of reasonableness can be just and reasonable, subject to the following restriction.

80. In place of limiting ROE incentives to the zone of reasonableness, we propose to establish a cap on total ROE incentives applicable to all public utilities regardless of their associated risk profiles. Since Order No. 679, the Commission has regularly reduced an applicant's requested ROE incentive when the cumulative number has appeared high based on the risks of the transmission project.[83] In order to provide applicants additional certainty on how the Commission will review requests for ROE incentives, we propose to adopt a 250-basis-point cap for all ROE incentives consistent with our precedent and propose that ROE incentives up to and including this cap will be just and reasonable as required by section 219(d). However, as discussed above, this cap would not be subject to the zone of reasonableness used to establish a public utility's base ROE.

81. We seek comment on this proposal, including on the level of the cap on the ROE incentives requested by applicants. In light of the changes in base ROE policy, we also seek comment on whether the Commission should allow applicants, on a case-by-case basis, to seek removal of the zone-of-reasonableness conditions placed on previously granted incentives and to replace those restrictions with a hard cap on the incentives they have been granted.

D. Non-ROE Incentives

82. We propose in § 35.35(d)(2)–(7) of the revised Transmission Incentives Regulations to continue to provide non-ROE incentives.[84] These incentives will be available to all transmission projects that demonstrate that they either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. These incentives include: Abandoned Plant Incentive, CWIP Incentive, hypothetical capital structures, accelerated depreciation for rate recovery, and regulatory asset treatment.[85] These incentives facilitate the development of beneficial transmission and are consistent with a benefits-based approach. Applicants for these incentives will remain eligible for the rebuttable presumptions that transmission projects which are approved through regional transmission planning processes or state siting approvals ensure reliability or reduce the cost of delivered power by reducing congestion.[86]

83. We continue to believe that an overly rigid approach to hypothetical capital structures may discourage the development of transmission projects and recognize that the instances where hypothetical capital structure are and can be used reflect unique circumstances.[87] Accordingly, we propose in § 35.35(d)(4) of the revised Transmission Incentives Regulations to allow applicants to request a hypothetical capital structure and will continue to evaluate such requests on a case-by-case basis. An applicant must demonstrate that the proposed hypothetical capital structure is suited to the unique circumstances of its transmission project as part of its showing that the requested incentives are just and reasonable and not unduly discriminatory.

84. Additionally, we recognize that transmission planning and selection has changed significantly since the issuance of Order Nos. 679 and 679–A, particularly with the implementation of Order No. 1000. We believe that these changes should be reflected in our transmission incentives policy and, therefore, propose to revise § 35.35(j)(2) of the Transmission Incentives Regulations to change the start of the effective date for the Abandoned Plant Incentive from the date that the Commission issues an order granting 100 percent recovery of abandoned plant costs to the date that transmission projects are selected in a regional transmission planning process for the purposes of cost allocation. Starting the eligibility period for the Abandoned Plant Incentive at the date of approval by the Commission leads to the exclusion of costs incurred between approval of the transmission project by the regional transmission planning process and Commission approval of the incentive, and this delay is not warranted for purposes of cost control, because the transmission planner has made the decision to undertake the transmission project.[88] Under this proposal, in order to recover any costs under the Abandoned Plant Incentive, an applicant must continue to demonstrate in a FPA section 205 filing that the transmission projects were abandoned for reasons outside of its control and that the costs incurred were prudent.

[82] Order No. 679, 116 FERC ¶ 61,057 at P 93.

[83] *See, e.g., Atl. Grid Operations A LLC,* 135 FERC ¶ 61,144, at PP 7, 128 (2011) (reducing a requested 300 basis point ROE incentive to 250 basis points); *Primary Power, LLC,* 131 FERC ¶ 61,015, at PP 8, 152 (2010) (reducing a requested 300 basis point ROE incentive to 200 basis points), *order on reh'g,* 140 FERC ¶ 61,052 (2012), *pet. for review dismissed sub. nom, Public Service Elec. and Gas Co.* v. *FERC,* 783 F.3d 1270 (2015); *N.Y. Reg'l Interconnect, Inc.,* 124 FERC ¶ 61,259, at PP 2, 44 (2008) (reducing a requested 400 basis point ROE incentive to 275 basis points).

[84] These incentives are provided under § 35.35(d)(1)(ii)–(viii) of the currently effective Transmission Incentives Regulations.

[85] *See* 18 CFR 35.35(d)(1)(ii)–(viii).

[86] *Id.* at 35.35(i).

[87] *See* Order No. 679, 116 FERC ¶ 61,057 at PP 132, 134.

[88] *See, e.g.,* American Electric Power Company, Inc., Docket No. PL19–3–000, Comments, at 18 (filed June 26, 2019) (AEP Comments); Pacific Gas & Electric Company and San Diego Gas & Electric Company, Comments, Docket No. PL19–3–000, at 11–13 (filed June 26, 2019).

E. Incentives Available to Transcos

1. Background and Experience to Date

85. In Order No. 679, the Commission acknowledged the promise of Transcos in catalyzing needed investment in transmission facilities that further FPA section 219's policy objectives of ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[89] The Commission stated that Transcos ''have demonstrated the capability to invest, on a timely basis, significant amounts of capital in transmission projects and in efforts to reduce congestion.'' [90] The Commission attributed the positive record of Transco investment in transmission facilities to the stand-alone nature of these entities, which the Commission believed: (1) Reduced the competition between generation and transmission functions within corporations; (2) produced incentives to better manage transmission assets and develop innovative services; (3) granted better access to capital markets given a more focused business model; and (4) enabled better responses to market signals that indicate when and where transmission investment is needed. The Commission also noted that, unlike many traditional public utilities, Transcos avoid potential uncertainty associated with the need for additional rate recovery approval from state regulators.[91]

86. In recognition of these beneficial attributes and a desire to promote and remove barriers to Transco formation, the Commission formalized two incentives available exclusively to Transcos: (1) An ROE incentive to be applied to an eligible Transco's entire rate base (Transco ROE Incentive),[92] and (2) an alternative ratemaking treatment that adjusts the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities (Transco ADIT Adjustment).[93] Regarding the Transco ROE Incentive, the Commission's policy requires that any incentive ROE awarded to Transcos both encourage their formation and be sufficient to attract investment after the Transco is formed.[94] Regarding the Transco ADIT Adjustment, the Commission indicated that it would continue to consider requests for that ratemaking treatment on a case-by-case basis when a Transco is purchasing existing transmission facilities.[95]

87. As discussed above, in the nearly 14 years since Order No. 679, there have been significant developments in how transmission is planned, developed, operated, and maintained. When the Commission adopted Order No. 679, there was a shortage of transmission investment and development. The Commission recognized the potential of Transcos to assist in addressing the lack of transmission development and formalized the Transco ROE Incentive to encourage these capabilities. However, we have not seen evidence of Transcos delivering the outcomes that the Commission had expected in establishing Transco incentives in Order No. 679.

88. For instance, in Order No. 679, the Commission articulated an expectation that Transcos would be uniquely positioned to build, on a timely basis, significant amounts of transmission assets to further the policy objectives of FPA section 219.[96] The Commission's expectation was based, in part, on observations of high levels of deployment of transmission plant among Transcos prior to Order No. 679.[97] However, with hindsight, we have found that those investment levels were transitory, and that Transcos are deploying capital to support transmission development in a manner that is comparable and not significantly greater than that of their traditional public utility counterparts.[98] Several commenters similarly note that Transcos have not exhibited the remarkable levels of transmission investment on which the Commission justified the Transco ROE Incentive.[99]

89. Additionally, in Order No. 679 the Commission found that concerns regarding high rates for Transco customers were speculative.[100] However, experience to date has shown those concerns to be valid. For example, the network rates for ITC Midwest, a subsidiary of ITC Holdings Corp., have been the highest in MISO since 2010, while network rates for its sister company Michigan Electric Transmission Company have exceeded the MISO median in all but one year since 2009.[101] Some commenters also echo concerns regarding elevated rates among Transcos.[102] Against this backdrop, we note that several commenters argue that increasingly robust transmission planning processes—in part because of the independent role of RTOs/ISOs and Commission reforms such as Order No. 1000—may have helped achieve investment outcomes comparable to those envisioned by the Commission in Order No. 679 when it established the Transco ROE Incentive.[103]

90. Furthermore, the Transco business model that the Commission envisioned in approving Transco incentives under FPA section 205 and then in Order No. 679 was one of robust independence.[104] However, currently, the majority of Transcos have started out as, or become, transmission affiliates of integrated utilities.[105] Such entities do not provide assurance of an absence of conflicts of interest with generation-owning affiliates or of a singular focus on transmission investment and operation. Further, the availability of these incentives for Transcos has not elicited the formation of many new Transcos. Since 2006, the Commission has granted the Transco ROE Incentive to 12 entities,[106] some of which never

[89] Order No. 679, 116 FERC ¶ 61,057 at P 206; *Promoting Transmission Investment through Pricing Reform,* Notice of Proposed Rulemaking, 113 FERC ¶ 61,182, at P 38 (2005) (2005 Transmission Incentives NOPR).

[90] 2005 Transmission Incentives NOPR, 113 FERC ¶ 61,182 at P 38.

[91] *Id.* P 39.

[92] 18 CFR 35.35(d)(2)(i); Order No. 679, 116 FERC ¶ 61,057 at P 221.

[93] 18 CFR 35.35(d)(2)(ii); Order No. 679, 116 FERC ¶ 61,057 at PP 247–248.

[94] 18 CFR 35.35(d)(2); Order No. 679, 116 FERC ¶ 61,057 at P 221.

[95] Order No. 679, 116 FERC ¶ 61,057 at P 248.

[96] *Id.* PP 225–226*; see also* 2005 Transmission Incentives NOPR, 113 FERC ¶ 61,182 at P 38.

[97] Order No. 679, 116 FERC ¶ 61,057 at P 222.

[98] For example, transmission plant growth rates for subsidiaries of ITC Holdings Corp., a large Transco holding company, are within the normal range of other transmission owners in MISO, where those subsidiaries operate.

[99] Aluminium Association, et al., Joint Comments, Docket No. PL19–3–000, at 67 (filed June 26, 2019) (Joint Commenters Comments); Resale Power Group of Iowa Comments, Docket No. PL19–3–000, at 22–23 (filed June 26, 2019) (Resale Power Comments); Transmission Access Policy Study Group Comments, Docket No. PL19–3–000, at 93 (filed June 26, 2019) (TAPS Comments).

[100] Order No. 679, 116 FERC ¶ 61,057 at P 228.

[101] This reflects our analysis of MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff Schedule 9 Network Rates posted on MISO's Open Access Same-Time Information System. *See* MISO, *Transmission Rate Information, https://www.oasis.oati.com/woa/docs/MISO/MISOdocs/Transmission_Rates.html.*

[102] Resale Power Comments at 26; Joint Commenters Comments at 68.

[103] Resale Power Comments at 21–22; TAPS Comments at 93; Joint Commenters Comments at 67; Oklahoma Corporation Commission Comments, Docket No. PL19–3–000, at 1 (filed June 27, 2019) (Oklahoma Commission Comments).

[104] *See* Order No. 679, 116 FERC ¶ 61,057 at P 202.

[105] The ITC companies were acquired by Fortis Inc., which owns multiple vertically integrated utilities. *See Fortis Inc.,* 156 FERC ¶ 61,219, at P 1 (2016), *order on clarification,* 158 FERC ¶ 61,019 (2017). NextEra Energy, which owns, NextEra Energy Transmission, also owns Florida Light and Power Company and a portfolio of generation resources across the country. *See NextEra Energy Transmission, LLC,* 166 FERC ¶ 61,188, at PP 3–6 (2019).

[106] The Commission granted a Transco ROE Incentive in the following 12 cases: *GridLiance West Transco LLC,* 164 FERC ¶ 61,049 (2018);

developed any transmission and several of which are affiliated with other Transcos. Meanwhile, transmission-only entities that may not qualify for, or have not requested, the Transco ROE Incentive have continued to invest in transmission and, notably, participate in competitive transmission solicitations.

2. Proposed Revisions to Transco Incentives

91. We acknowledge the role that individual Transcos have played, and continue to play, in deploying new transmission infrastructure; however, we believe that the Transco business model has not enhanced the deployment of transmission infrastructure sufficiently to justify incentives based on this business model beyond those incentives available to all public utilities. We find that the circumstances have changed significantly since Order No. 679 and that the key reasoning underpinning the Commission's policy for establishing a Transco ROE Incentive and a Transco ADIT Adjustment no longer apply. Accordingly, we propose to revise our regulations to eliminate both of those incentives prospectively by removing current sections 35.35(b)(1) and 35.35(d)(2) of the Transmission Incentives Regulations. Although we propose to eliminate those incentives exclusively available to Transcos, we do not revoke eligibility for Transcos to seek the incentives available to all public utilities as proposed in this NOPR. We view the suite of incentives for which Transcos (and all public utilities) remain eligible, in addition to those incentive proposals contemplated elsewhere in this NOPR, as sufficient to attract capital needed to achieve the transmission investment objectives articulated in FPA section 219. We invite comment on this proposal. We also seek comment regarding how the Commission should treat Transco ROE Incentives that were previously granted.

F. Incentives for RTO Participation

1. Background and Experience to Date

92. FPA section 219(c) requires the Commission to ''provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization.'' In Order No. 679, the Commission found that the RTO-Participation Incentive should be granted to utilities that ''join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization.'' [107] The Commission declined to make a finding on the appropriate size or duration of the RTO-Participation Incentive, but noted that the basis for providing the incentive to existing members ''is a recognition of the benefits that flow from membership in such organizations and the fact [that] continuing membership is generally voluntary.'' [108] The Commission also declined to create a generic ROE incentive for such membership, and instead decided that it would consider the appropriate ROE incentive when public utilities requested it on a case-by-case basis.[109] Although the Commission declined to make a finding on the appropriate size or duration of the incentive in Order No. 679, applicants have subsequently requested a uniform, 50-basis-point level for demonstrating they have joined an RTO or ISO, which the Commission has granted without modification.

93. The stated purpose of FPA section 219 is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. We believe the RTO-Participation Incentive has not only encouraged the formation of and participation in RTOs/ISOs, but also has resulted in significant benefits for consumers. Specifically, PJM estimates that the total annual benefits and savings to PJM's customers in the 13 states and the District of Columbia in which it operates to be between $3.2 and $4 billion; [110] SPP estimates that savings from its markets and transmission planning services provide more than $2.2 billion annual benefits to its members at a benefit-to-cost ratio of 14-to-1; [111] and MISO estimates that MISO delivered between $3.2 billion and $3.9 billion in regional benefits in 2018.[112] Although RTO/ISO participation provides substantial benefits for customers, we agree with commenters that the RTO-Participation Incentive also compensates transmitting utilities for the ongoing duties and responsibilities of RTO/ISO membership.[113]

94. In Order No. 679, the Commission stated that the basis for the RTO-Participation Incentive is ''a recognition of the benefits that flow from membership in such organization and the fact [that] continuing membership is generally voluntary.'' [114] The RTO-Participation Incentive was not only intended to induce transmitting utilities to turn over operational control over their transmission facilities to Transmission Organizations, but also to recognize the benefit to consumers of RTO/ISO membership by ensuring reliability and reducing the cost of delivered power by reducing congestion. Experience to date has demonstrated that the benefits from membership in a Transmission Organization is significant regardless of the voluntariness of such membership. These benefits include access to large competitive markets, optimization of the transmission system, regional transmission planning that supports more efficient or cost-effective transmission development to meet regional transmission needs, reduction of the costs of carrying reserves through reserve sharing, and increased access to an expanded set of diverse resources. All of these attributes reduce the cost of delivered power by facilitating broader and more robust access to more sources of power, and to the lowest-cost source of power, over a wide geographic footprint. These benefits have increased over time. PJM notes that its value proposition for consumers has increased over the past 13 years to a current estimate of $3.2 to $4.0 billion,[115] an increase from an estimated $2.2 billion in 2011.[116]

95. FPA section 219(c) contains no requirement that participation in an RTO/ISO must be voluntary to merit the

NextEra Energy Transmission N.Y., Inc., 162 FERC ¶ 61,196 (2018); *Midcontinent Indep. Sys. Op., Inc.,* 150 FERC ¶ 61,252 (2015), *order on clarification and reh'g,* 154 FERC ¶ 61,004 (2016); *Desert Southwest Power, LLC,* 135 FERC ¶ 61,143 (2011); *Atl. Grid Operations A LLC,* 135 FERC ¶ 61,144; *Western Grid Development, LLC,* 130 FERC ¶ 61,056, *order on reh'g,* 133 FERC ¶ 61,029 (2010); *Primary Power,* 131 FERC ¶ 61,015; *Green Energy Express LLC,* 129 FERC ¶ 61,165 (2009), *order on reh'g,* 130 FERC ¶ 61,117 (2010); *Green Power Express LP,* 127 FERC ¶ 61,031 (2009), *order on reh'g,* 135 FERC ¶ 61,141 (2011); *ITC Great Plains, LLC,* 126 FERC ¶ 61,223 (2009), *order on reh'g,* 150 FERC ¶ 61,225 (2015); *N.Y. Reg'l Interconnect,* 124 FERC ¶ 61,259; *Startrans IO, L.L.C.,* 122 FERC ¶ 61,306 (2008), *order on reh'g,* 133 FERC ¶ 61,154 (2010).

[107] Order No. 679, 116 FERC ¶ 61,057 at P 326.

[108] *Id.* PP 327, 331.

[109] *Id.* P 327.

[110] *See* PJM Interconnection, L.L.C., Comments, Docket No. PL19–3–000, at 6–7 (filed June 26, 2019) (PJM Comments).

[111] *See* SPP, *14-to-1 The Value of Trust,* at 3 (May 29, 2019), *https://spp.org/documents/58916/14-to-1%20value%20of%20trust%2020190524%20web.pdf.*

[112] *See* MISO, *2019 Value Proposition,* at 5 (Feb. 7, 2020), *https://cdn.misoenergy.org/20200214%202019%20Value%20Proposition%20Presentation425712.pdf.*

[113] *See* Edison Electric Institute Comments, Docket No. PL19–3–000, at 23 (filed June 26, 2019) (EEI Comments); PJM Comments at 4–5.

[114] Order No. 679, 116 FERC ¶ 61,057 at P 331.

[115] PJM Comments at 7.

[116] *See* FERC, *2011 Report to Congress on Performance Metrics for Independent System Operators and Regional Transmission Organizations,* app. H at 313 (Apr. 2011), *https://www.ferc.gov/industries/electric/indus-act/rto/metrics/pjm-rto-metrics.pdf.*

incentive; rather, it states the Commission shall provide for incentives. Neither the benefits that customers receive from a transmitting utility's or electric utility's membership in an RTO/ISO, nor the burden imposed upon the transmitting utility or electric utility, are diminished if the transmitting utility or electric utility is required by law to join an RTO or ISO.

96. The duties and responsibilities associated with RTO/ISO membership have also increased since Order No. 679. These include: loss of operational control of transmission facilities to a third party; an obligation to build new transmission facilities at the direction of the RTO/ISO; diminished decision-making control over assets while retaining the responsibility of maintaining the system; meeting reliability standards; obligations to obey RTO/ISO rules; and an obligation to provide electric service even when foundational agreements can change, thereby changing the terms and conditions under which the transmitting utility initially agreed to participate in the RTO/ISO.[117] These responsibilities similarly persist regardless of the voluntariness of RTO/ISO membership.

2. RTO-Participation Incentive Proposal

97. We propose to combine and modify §§ 35.35(b)(2) and 35.35(e) of the existing Transmission Incentives Regulations in § 35.35(f) of the revised Transmission Incentives Regulations to provide transmitting utilities that turn over their wholesale transmission facilities to the RTO/ISO [118] a fixed 100-basis-point RTO-Participation Incentive, and modify its implementation, as discussed below. The benefits of having centralized electricity markets and regional transmission planning conducted by an RTO/ISO, combined with compensating RTO/ISO participants for their added responsibilities, support the Congressional mandate of an RTO-Participation Incentive to encourage transmitting utilities to turn planning and operational control over their transmission facilities to Transmission Organizations. Standardizing and increasing the level at which this incentive is awarded reasonably recognizes the increased customer value resulting from transmitting utilities joining and continuing to participate in an RTO/ISO since the issuance of Order No. 679. It also recognizes the increased duties and responsibilities associated with RTO/ISO membership since the issuance of Order No. 679, including, *inter alia,* the development of regional transmission planning processes. These additional roles and responsibilities of RTOs/ISOs and their transmission owners have benefited customers, as illustrated by the increased and substantial benefits demonstrated by RTOs/ISOs. For instance, as noted above, PJM has stated that its value proposition for consumers is $3.2 to $4.0 billion in annual savings, an increase from an estimated $2.2 billion in 2011. Additionally, from 2007 through 2019, the Value Proposition study revealed that MISO provided the region an estimated $26 billion in cumulative net benefits.[119] In order to address regulatory uncertainty and fulfill our directive to offer an incentive for RTO membership, we find that the RTO-Participation Incentive remains an effective incentive to recognize the benefits, risks, and associated obligations of RTO membership and meet the requirements of FPA section 219(c).

98. As noted by commenters to the 2019 Notice of Inquiry, permitting some RTO/ISO members to receive the RTO-Participation Incentive, while disallowing the RTO-Participation Incentive for entities that are required to join or remain in an RTO/ISO, would create an uneven playing field in the competition for investment capital.[120] Such an uneven playing field has the potential to distort investment decisions within interstate corporate families and within multistate RTOs/ISOs. Furthermore, FPA section 219 obligates the Commission to provide an incentive to each transmitting utility or electric utility that joins a Transmission Organization, independent of the obligation to do so.[121] We also note that the issue of whether RTO/ISO membership is voluntary for certain transmitting utilities within RTOs/ISOs has become subject to litigation and challenges at the Commission.[122] Accordingly, we propose that the RTO-Participation Incentive should be applied to transmitting utilities that join and remain enrolled in an RTO/ISO regardless of the voluntariness of their participation.

99. We propose to continue to permit transmitting utilities or electric utilities that join an RTO/ISO the ability to recover prudently incurred costs associated with joining the RTO/ISO in their jurisdictional rates. Additionally, we propose to standardize the RTO-Participation Incentive at a uniform level of 100 basis points to a transmitting utility that joins and continues to be a member of an RTO/ISO and turns over operational control of its wholesale transmission facilities to the RTO/ISO.[123] We propose that both transmitting utilities newly joining an RTO/ISO and those that already receive the current RTO-Participation Incentive would be eligible to seek the new 100-basis-point adder. We request comment on this proposal, including comment on what process the Commission should adopt to implement a 100basis point RTO-Participation Incentive for existing transmitting utility rates.

G. Incentives for Transmission Technologies

1. Background and Experience to Date

100. FPA section 219(b)(3) directs the Commission to encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the transmission facilities.[124] Under the 2012 Policy Statement, the Commission considers the incorporation of advanced technologies to transmission projects as part of the risks and challenges that may

[117] *See, e.g.,* EEI Comments at 22; Ameren Services Company Comments, Docket No. PL19–3–000, at 24 (filed June 26, 2019); AEP Comments at 13.

[118] 16 U.S.C. §824s(c). While the rest of the proposals in this proposed rule apply to public utilities, the proposal in the section related to RTO participation apply to ''transmitting utility'' or ''electric utility'' as required by Congress in FPA section 219(c).

[119] MISO, *2019 Value Proposition,* at 3 (Feb. 7, 2020), *https://cdn.misoenergy.org/20200214%202019%20Value%20Proposition%20Presentation425712.pdf.*

[120] EEI Comments at 23–24.

[121] 16 U.S.C. 824s(c).

[122] *See Cal. Pub. Util. Comm'n* v. *FERC,* 879 F.3d 966, 980 (9th Cir. 2018) (remanding to the Commission the issue of whether PG&E was eligible for a 50-basis-point RTO-Participation Incentive for its continued participation in CAISO in light of protestors' arguments that PG&E's participation in CAISO is mandated by California state law); N.Y. State Dept. of Pub. Serv., Protest, Docket No. ER20–715–000, at 5 (filed Jan. 21, 2020) (protesting that Central Hudson Gas & Electric Corp. should not receive an RTO-Participation Incentive because it is already a member of NYISO).

[123] *See PPL Elec. Util. Corp.,* 123 FERC ¶ 61,068, at P 35 (2008) (finding that a ''50-basis-point adder is appropriate. The consumer benefits, including reliable grid operation, provided by such organizations are well documented and consistent with the purpose of [FPA] section 219. The best way to ensure these benefits is to provide member utilities of an RTO with incentives for joining and remaining a member.''); *Republic Transmission, LLC,* 161 FERC ¶ 61,036, at P 33 (2017) (approving 50-basis-point RTO-Participation Incentive ''based on Republic's commitment to become a member of MISO and transfer operational control of the Project to MISO once the Project has been placed in service''); *Pac. Gas & Elec. Co.,* 148 FERC ¶ 61,195, at P 16 (2014) (granting request for a 50-basis-point RTO-Participation Incentive ''based on [Pacific Gas and Electric Company's (PG&E)] commitment to remain a member of CAISO, and its commitment to transfer functional control of the Project to CAISO once the Project enters service'').

[124] 16 U.S.C. 824s(b)(3).

warrant an increase in the ROE. The Commission evaluates deployment of advanced technologies as part of the overall nexus analysis when an incentive ROE is sought; there is currently no standalone incentive for advanced technology. Additionally, the current framework does not provide a standalone incentive for technology improvements to existing transmission projects. Experience to date suggests that this approach to incentivizing transmission technologies has not been effective in encouraging deployment of such improvements. For example, many transmission technologies discussed at the November 5–6, 2019 Grid-Enhancing Technologies Workshop [125] are smaller in scale, and do not face the same challenges as large capital-intensive transmission projects, such as siting and regulatory approvals.[126] Furthermore, many of the costs of transmission technologies are not currently capitalized and hence do not benefit from ROE incentives.[127]

2. Proposed Incentives

101. To comply with the directives of FPA section 219(b)(3) and more effectively promote the deployment of transmission technologies, we propose to add § 35.35(e) of the revised Transmission Incentives Regulations to offer rate treatments for transmission technologies that, as deployed in certain circumstances, enhance reliability, efficiency, capacity, and improve the operation of new or existing transmission facilities. Examples of technology types that represent such technologies in certain deployments at this time include: (1) Advanced line rating management; (2) transmission topology optimization; and (3) power flow control. For purposes of these incentives, we will generally not consider eligible transmission technologies to include transmission system assets traditionally associated with the transportation of electric power, such as power lines, power poles, capacitors, and other substation equipment.

102. In order to encourage the development of the technology for particular needs identified in different transmission planning processes, we decline to list the types of technologies eligible for transmission technology incentives. Instead, we will make a case-by-case determination of eligibility based on the characteristics of the technology and the benefits that the technology offers.

103. We propose that each public utility seeking incentives under this section must demonstrate that the technology, as applied in a particular transmission project (or stand-alone transmission technology project as described below), meets the above criteria for eligible transmission technologies and that the transmission technology project meets the economic benefits ROE incentive benefit-to-cost threshold proposed in this NOPR.[128] Developers seeking to deploy a transmission technology that meets these requirements may apply for a 100-basis-point ROE incentive on the cost of the specified transmission technology project (Transmission Technology Incentive) and a two-year regulatory asset treatment for costs related to deploying and operating that technology (Deployment Incentive). While the two proposed incentives are intended to work in conjunction, to accommodate unique accounting practices and flexibility, each incentive may be sought individually.

104. Noting that in response to the 2019 Notice of Inquiry and the Grid-Enhancing Technologies Workshop, we received feedback on alternate incentive proposals for transmission technologies, we seek comment on the proposed Transmission Technology Incentive and Deployment Incentive to effectively promote the deployment of transmission technologies.

a. Transmission Technology Incentive

105. We propose to add § 35.35(e) of the revised Transmission Incentives Regulations so that a public utility seeking to deploy transmission technologies that enhance reliability, efficiency, capacity, and improve the operation of new or existing transmission facilities may seek a 100-basis-point ROE Transmission Technology Incentive on the cost of the specified transmission technology project. The Transmission Technology Incentive may be applied to deployment of such technologies on either a new or existing transmission facility and is subject to the overall 250-basis-point cap proposed in this NOPR.[129] Because the proposed Transmission Technology Incentive is only applicable to the costs of the particular transmission technology, inclusive of any costs awarded regulatory asset treatment (as discussed below), the amount included in the 250-basis-point limit for an applicant seeking transmission incentives on its transmission project will be calculated on a weighted average, based on the cost of the technology relative to the cost of the entire transmission project.

$$\frac{Cost\ of\ Transmission\ Technology(ies)^{130}}{Cost\ of\ Entire\ Transmission\ Project} = Weighted\ Cost\ (WC)$$

$$WC \times Transmission\ Technology\ Incentive\ (in\ basis\ points) = Contribution\ to\ ROE\ Adder\ Cap\ (in\ basis\ points)$$

106. For instance, a developer with a $100 million transmission project that is awarded the Transmission Technology Incentive on a $10 million transmission technology project sub-component, would contribute 10 basis points to its 250-basis-point cap. Conversely, if a transmission project developer is awarded the Transmission Technology Incentive for a stand-alone transmission technology project, the incentive would contribute 100 basis points to its 250-

[125] FERC, *Grid-Enhancing Technologies,* Notice of Workshop, Docket No. AD19–19–000 (Sept. 9, 2019).

[126] *See, e.g.,* Advanced Energy Economy, Comments, Docket No. PL19–3–000, at 20 (filed June 26, 2019) (Advanced Energy Economy Comments); Energy Storage Association, Comments, Docket No. PL19–3–000, at 4 (filed June 25, 2019); Public Interest Organizations, Comments, Docket No. PL19–3–000, at 35 (filed June 26, 2019); Oklahoma Commission Comments at 1; TAPS Comments at 101; National Grid USA, Comments, Docket No. PL19–3–000, at 42 (filed June 26, 2019).

[127] *See, e.g.,* Advanced Energy Economy Comments at 20; Oklahoma Commission Comments at 1; Working for Advanced Transmission Technologies, Comments, Docket No. PL19–3–000, at 4 (filed June 26, 2019).

[128] *See supra* section IV.B.1.d.

[129] *See supra* section IV.C.

[130] Inclusive of any costs awarded regulatory asset treatment under the Deployment Incentive described below. *See infra* section IV.G.2.b.

basis-point cap. For purposes of this incentive, a stand-alone transmission technology project is the addition of solely a transmission technology to an existing transmission facility, or a transmission technology that by itself constitutes a new transmission facility.

107. We propose this incentive mechanism to encourage the deployment of innovative and cost-effective technologies that will bring consumer saving through congestion relief and increased efficiency of the transmission system consistent with the goals of FPA section 219. We seek comment on this proposed incentive, including the amount of this incentive, its limitation to the cost of the specified transmission technology project only, and its inclusion in the 250-basis-point cap on a weighted average. We also seek comment on whether this proposed incentive is proportional to the benefits offered to consumers by eligible transmission technologies and if this incentive is sufficient to attract investment in such transmission technologies.

b. Deployment Incentive

108. There are significant upfront costs and obstacles to public utilities seeking to deploy transmission technologies that offer consumer benefits.[131] Many of these costs reflect significant changes to the transmission system, such as the increase of software and service-based costs in transmission operations that often require retraining of the workforce. To overcome these obstacles and encourage deployment of eligible transmission technologies that will lower the cost of delivered power and increase reliability, we propose to add § 35.35(e)(2) of the revised Transmission Incentives Regulations to allow certain initial costs related to deploying technologies that are traditionally expensed in the year incurred to be deferred as a regulatory asset and included in rate base for purposes of determining a public utility's return on equity. We propose to defer up to two years of specified initial costs for the installation and operation of the eligible transmission technology, that would otherwise be expensed in the year incurred, to be amortized over a five-year period. For purposes of this incentive, we propose that the two-year period of cost eligibility will begin at the procurement stage, exclusive of planning activities.

109. The Deployment Incentive is intended to ease the implementation burden for transmission technologies and incent developers to deploy them. As such, this incentive is only permitted one time per technology per applicant and will be limited to two years in duration. Allowing these costs in rate base prior to and during initial commercial operation provides a public utility with additional cash flow in the form of an immediate earned return. The financial benefit to public utilities is warranted by the increased efficiency and congestion savings these technologies offer to consumers.

110. In addition to inviting comment generally on this proposed rate treatment, we specifically request comment on: (1) The types of costs that are not currently capitalized (and not currently eligible for the recovery of prudently incurred pre-commercial operation costs under the regulatory asset incentive available under § 35.35(d)(1)(iii) of the existing Transmission Incentives Regulations) that should be eligible for regulatory asset treatment; (2) the duration of the regulatory asset treatment; (3) the total amount of costs for deploying certain eligible transmission technologies, including software; and (4) whether these proposed incentives are sufficient to overcome obstacles to the first deployment of an eligible transmission technology.

3. Eligibility and Requirements

a. Transmission Technology Statement

111. We propose to add § 35.35(e)(3) of the revised Transmission Incentives Regulations to require each public utility along with its application for the Transmission Technology Incentive or the Deployment Incentive, to submit a transmission technology statement that demonstrates: How the technology meets the transmission technology criteria above, the expected benefits of deployment, the cost of the transmission technology project, the cost of the overall transmission project if not a stand-alone transmission technology project, the expected useful life of the asset, and a demonstration that the transmission technology meets the economic benefits threshold provided in this NOPR.[132] We request comment on this proposal.

b. Pilot Programs

112. We propose to add § 35.35(e)(4) of the revised Transmission Incentives Regulations to allow pilot programs for eligible transmission technologies that meet the above criteria to receive a rebuttable presumption of eligibility for the Transmission Technology Incentive and the Deployment Incentive. For purposes of these incentives, we propose to define a pilot program as a public utility-led deployment of an eligible transmission technology, with costs under $25 million for each eligible transmission technology project, that has not been deployed to or operated on more than five percent of the applicant's transmission system,[133] and has a maximum duration of two years from installation to completion. Additionally, utilities that have completed a pilot program for an eligible transmission technology, but have not moved to deployment, will be eligible for the rebuttable presumption if they meet the pilot program criteria and demonstrate a plan for higher deployment. We seek comment on the limitations on pilot programs; specifically, on the percentage of deployment and duration of the pilot.

c. Reporting Requirement

113. We propose to add § 35.35(e)(5) of the revised Transmission Incentives Regulations which states that each public utility that receives the Transmission Technology Incentive or Deployment Incentive must submit an annual informational filing, for three years after the incentive is granted, to the Commission that details the progress of the technology, obstacles to its deployment and efforts to overcome them, lessons learned, and any quantifiable data measuring the benefits of the transmission technology project. Any duplicative data already submitted under Form 730, as revised in this NOPR,[134] need not be submitted. Collected data will not be used for ex-post analysis for the purpose of revising the awarded incentives. We propose to collect the data for internal analysis and provide an annual update of transmission technology development to benefit the industry and encourage widespread deployment of beneficial transmission technologies.

H. Disclosure of Anticipated Incentives

114. As discussed above, there have been significant developments in the regional transmission planning process since the adoption of FPA section 219 and the Commission's issuance of Order Nos. 679 and 679–A. We seek comment on whether it would be useful to require

[131] *See* Advanced Energy Economy Comments at 20–21; Grid-Enhancing Technologies Workshop Transcript Day 1 at 69, 77–82, 86–91, 95–98.

[132] *See supra* section IV.B.1.d.

[133] To determine whether an applicant's pilot program is eligible under this sub-section, we propose to consider an applicant's transmission system to include any affiliate companies' transmission systems that are within the same region as the transmission technology project seeking incentives, and exclude the affiliate companies' transmission systems outside of that region.

[134] *See infra* section IV.I.1.

a public utility seeking incentives to disclose all reasonably anticipated incentives to transmission planning regions as part of the public utility's transmission project proposal. We also seek comment on whether such a requirement should apply to all incentive applications or only to incentive applications for an increased ROE.

I. Program Management

1. FERC Form 730

115. As stated above, FPA section 219 provides that the Commission is to encourage transmission development for the purpose of benefitting consumers. To ensure that existing and proposed incentives are successfully meeting the objectives of FPA section 219, the Commission needs industry data, projections, and related information that detail the level of investment and the costs and benefits of transmission projects. Experience to date suggests that current information collection related to FPA section 219 incentives is insufficient to determine the effectiveness of individual incentive grants, or to evaluate the Commission's overall incentives program.

116. Order No. 679 established a reporting requirement associated with transmission projects that receive project-specific transmission incentives.[135] Order No. 679 created Form 730, which contains two reporting tables. Table 1 is an aggregate of the spending by a public utility over all the transmission projects that received incentives; Table 2 is a project-by-project status update. Under the current rules, jurisdictional public utilities are required to report annually to the Commission, on the date on which FERC Form No. 1 (Form 1) information is due, the following data and projections: (subsection i) in dollar terms, actual investment for the most recent calendar year and planned investments for the next five years; and (subsection ii) for all current and planned investments over the next five years, a project-by-project listing that specifies the expected completion date, percentage completion as of the date of filing and reasons for delay.[136] The information required in Form 730 is not available from FERC Form Nos. 1, 714, or 715, nor is it available from other federal agencies.

a. Form 730 Proposed Format Changes

117. We propose to retain the requirement in § 35.35(i) of the revised Transmission Incentives Regulations for public utilities that have been granted incentive rate treatment to file a Form 730 on an annual basis. However, we believe that there are several areas of improvement that can be made to Form 730's design to collect the necessary information without imposing undue burden on incentive recipients. The current aggregate reporting required on Form 730 can be difficult to interpret if the public utility has multiple transmission projects and multiple transmission incentive requests. The data reported in Table 1 is most useful when a public utility has requested incentives once for a single transmission project, or for multiple transmission projects, if a public utility reports the data in a project-by-project format rather than as an aggregate number.[137] Accordingly, we propose to modify § 35.35(i) of the revised Transmission Incentives Regulations to require that applicants provide the information on a project-by-project basis and propose other reforms to make the reporting requirement more effective, as detailed below.

118. We invite comment on the proposed modifications to the basic format and fields of Form 730,[138] specifically:

a. Require Table 1 data to display project-by-project data instead of aggregated data.

b. Identify each transmission project by a public utility-created transmission project code in each record of Table 1 and Table 2 to aid in merging the tables.

c. Add the report year to each record of Table 1 and Table 2.

d. Add the aggregate of actual spending on each transmission project prior to the report year to determine total actual spending on each transmission project for each year.

e. Add the aggregate of projected spending on each transmission project more than five years beyond the report year to estimate projected spending on each transmission project for each year.

f. Include a new column entitled ''Notes on Table 1'' that permits a 60-character text string, so public utilities can explain any issues in the data. Public utilities also have the option to add a footnote with no character limit to describe issues in as much detail as necessary. For example, public utilities can explain why cost forecasts have suddenly increased from a previous year.

g. Include Project Voltage as a field in Table 2. Previously, transmission project voltage was part of Project Description in Table 2. If no value can be used as the transmission project voltage, the number -9 is inserted to indicate that there is no value.

h. The data in Table 2 must be known as of midnight on December 31 of the record year. This is a clarification of a point of ambiguity in the original description of Table 2.

i. Modify the data in the column titled, ''If Project Not On Schedule, Indicate Reasons For Delay'' in Table 2 to a 60-character text string. Public utilities also have the option to add a footnote with no character limit so utilities can explain the reasons in more detail.

j. Report Form 730 data in eXtensible Business Reporting Language (XBRL). format.

119. The change to the XBRL data format for Form 730 reporting is consistent with the Commission's planned change to XBRL for Form 1 reporting.[139] The Commission has examined the transition to XBRL in depth and has provided justification and support for this change in data reporting format.[140] The same justifications apply in this context. For instance, XBRL will not only be a standard data format at the Commission; it is an international standard for digital reporting, and it enables the reporting of comprehensive, consistent, interoperable data that allows industry and other data users to automate submission, extraction, and analysis. XBRL is a language in which reporting terms can be authoritatively defined, and those terms can then be used to uniquely represent the contents of the Commission's data collections. XBRL is currently required for filing forms by a number of other federal agencies.

120. Additionally, XBRL provides an efficient way to exchange information inherent to the XML format and applies a standard way to capture the characteristics of that information. The XBRL standard also offers flexible benefits, including the ability to support simple formulas such as addition and subtraction and allow more complex formulas to be defined with a set of guidelines. We believe that requiring XBRL-based data would also lead to

[135] Order No. 679, 116 FERC ¶ 61,057 at P 367.

[136] *Id.* P 358.

[137] From June 2006 to March 2019, there were about 80 different developers that requested incentives. Of these developers, 60 have requested incentives only once.

[138] *See* Appendix B for a full draft of the proposed revised Form 730. These changes include the changes to the instructions requested by OMB and adopted by the instant final rule issued concurrently with this NOPR. Additional changes to Form 730 to track transmission project benefits are described in a section below.

[139] *Revisions to the Filing Process for Commission Forms,* Notice of Proposed Rulemaking, 166 FERC ¶ 61,027 (2019).

[140] *Id.* PP 4–18.

greater data quality through easier validation checks.

121. The transition to XBRL format will require modifications to the format of the current Form 730 Tables. However, the modifications and the data format reporting adjustments are justified by the aforementioned benefits, such as efficiency, consistency, and flexibility. We invite comment on the proposed changes to Form 730.

2. Scope of Public Utility Reporting Obligation

122. We propose to modify the scope of the public utilities reporting obligation for Form 730 to direct all public utilities that receive an incentive, other than the RTO-Participation Incentive, for any transmission project to submit information on Form 730 regardless of the transmission project's size. Currently, Order No. 679 only requires information reporting for transmission projects that cost $20 million or more [141] and we propose to eliminate this threshold. However, we propose that public utilities that receive only the RTO-Participation Incentive must report only for transmission projects that cost more than $3 million.[142] We seek comment on this general elimination of the threshold and the $3 million partial retention of it for some public utilities.

123. The expanded reporting obligation, as proposed here, would make Form 730 a more comprehensive forecast tool and permit the Commission to project how much transmission investment will occur in the next five years. Additionally, increasing the scope of the reporting requirement will allow the Commission to compare transmission projects and to evaluate the benefits of transmission projects awarded incentives. This will enable the Commission to evaluate the effectiveness of the incentives program and ensure that the Commission is meeting the statutory requirements of FPA section 219.

3. Benefits Reporting in Form 730

124. As proposed in this NOPR, the Commission's incentive policies will no longer focus on risks and challenges, but instead will evaluate the benefits of proposed transmission projects. In order to effectively evaluate the benefits and monitor the progress of transmission projects that have received incentives, we propose to modify Form 730 to include benefits metrics. We propose that reporting on benefits calculations, both the expected and the actual, should only apply to transmission projects that are $25 million or more in scale to reduce the reporting burden.

125. We also propose the following modifications to Form 730 to measure transmission project benefits:

a. Add a new column to Table 1 for the expected annual benefits of each transmission project.

b. Add a new Table 3 to record actual estimated benefits for each year for up to five years after the date of completion of the transmission project.

c. Incorporate the data in Tables 1 through 3 of Form 730 as new schedules in Form 1.

d. Require public utilities to report the estimated annual economic benefits of each transmission project that is under construction that receives any transmission incentive using the same methodology that would have been used to justify an economic transmission incentive regardless of whether that transmission project actually received an economic transmission incentive. Where possible, we propose to require such benefits to be calculated with the same methodology used by the RTO/ISO to determine economic benefits.

e. Require public utilities to report actual annual economic benefits of completed transmission projects that received any transmission incentive using actual data calculated using the same methodology that would have been used to justify an economic transmission incentive regardless if that transmission project actually received an economic transmission incentive. Where possible, we propose to require economic benefits to be calculated with the same methodology used by the RTO/ISO to determine economic benefits.

f. This annual economic benefit reporting requirement will be limited to the first full five years of the transmission project's implementation.

126. We request comment on the burden to public utilities to provide this benefit information.

V. Information Collection Statement

127. The information collection requirements contained in this NOPR are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[143] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[144] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

128. This NOPR would revise the Commission's regulations and policy with respect to the mechanics and implementation of the Commission's transmission incentives policy; and with respect to the metrics for evaluating the effectiveness of incentives. These provisions would affect the following collections of information:

- FERC–516, Electric Rate Schedules and Tariff Filings (Control No. 1902–0096); and
- FERC–730, Report of Transmission Investment Activity (Control No. 1902–0239).

129. Interested persons may obtain information on the reporting requirements by contacting Ellen Brown, Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 via email (*DataClearance@ferc.gov*) or telephone (202) 502–8663.

130. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

131. Please send comments concerning the collection of information and the associated burden estimates to: Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should refer to OMB Control Nos. 1902–0096 and 1902–0239.

132. Please submit a copy of your comments on the information collections to the Commission via the eFiling link on the Commission's website at *http://www.ferc.gov.* If you are not able to file comments electronically, please send a copy of your comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE,

---

[141] *See* Order No. 679, 116 FERC ¶ 61,057 at P 370.

[142] The threshold of $3 million is proposed because the Commission has had requests for incentives for transmission projects as small as $3 million. *See Va. Elec. Power Co.,* 124 FERC ¶ 61,207, at P 17 (2008).

[143] 44 U.S.C. 3507(d).

[144] 5 CFR 1320.11.

Washington, DC 20426. Comments on the information collection that are sent to FERC should refer to RM20–10–000.

Title: Electric Rate Schedules and Tariff Filings (FERC–516) and Report of Transmission Investment Activity (FERC–730).

Action: Proposed revision of collections of information in accordance with RM20–10–000

OMB Control Nos.: 1902–0096 (FERC–516) and 1902–0239 (FERC–730).

Respondents for this Rulemaking: Public Utilities that seek incentive-based rate treatment for transmission projects, public utilities for which the Commission has granted incentive-based rate treatment for transmission projects, RTOs/ISOs, and the non-RTO/ISO planning regions.

Frequency of Information Collection: On occasion, except for Form 730, which must be filed annually beginning with the calendar year the Commission grants incentive-based rate treatment, and except for the transmission technology annual report, which must be filed annually.

Necessity of Information: Required to obtain or retain benefits.

Internal Review: The Commission has reviewed the changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

133. The NERC Compliance Registry, as of January 31, 2020, identifies approximately 337 Transmission Owners in the United States that are subject to this proposed rulemaking. Additionally, there are six RTOs/ISOs and six planning regions which are not RTOs/ISOs, for a total of 12 planning regions overall.

134. The Commission estimates that the NOPR would affect the burden [145] and cost [146] of FERC–516 (eTariff Filings) and Form 730 as follows:

PROPOSED CHANGES IN NOPR IN DOCKET NO. RM20–10–000

Area of modification A.	Number of respondents B.	Annual estimated number of responses per respondent C.	Annual estimated number of responses (Column B × Column C) D.	Average burden hours & cost per response E.	Total estimated burden hours & total estimated cost (Column D × Column E) F.
FERC–516, eTariff Filings (for Planning Regions)					
RTO/ISO regions provide transmission planning data to developers that examine economic attributes of projects.	6	1.67	10	5 hours; $400	50 hours; $4,000.
Non-RTO/ISO regions provide transmission planning data to developers that examine economic attributes of projects.	6	0.83	5	5 hours; $400	25 hours; $2,000.
Sub-Total for Planning Regions					75 hours; $6,000.
FERC–516, eTariff Filings (for Transmission Owners)					
Developers in RTO/ISO regions provide data made available by a transmission planning region that examines economic attributes of projects.	10	1	10	40 hours; $3,200	400 hours; $32,000.
Developers in non-RTO/ISO regions submit showings of proposed transmission projects' economic merits by using economic modeling within transmission planning regions; or provide showings of economic benefits as determined by third party experts.	5	1	5	480 hours; $38,400	2,400 hours; $192,000.
Demonstration that project met or came in under the project costs for additional incentive.	5	1	5	120 hours; $9,600	600 hours; $48,000.
Demonstration of reliability benefits	10	1	10	360 hours; $28,800	3,600 hours; $288,000.
Demonstration for transmission technology incentive requests.	15	1	15	40 hours; $3,200	600 hours; $48,000.
Annual report on progress, obstacles, lessons learned, and quantifiable data for transmission technology deployment.	15	1	15	400 hours; $32,000	6,000 hours; $480,000.
Sub-Total for Transmission Owners					13,600 hours; $1,088,000.

[145] "Burden" is the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. For further explanation of what is included in the information collection burden, refer to 5 CFR 1320.3.

[146] Commission staff estimates that respondents' hourly wages (including benefits) are comparable to those of FERC employees. Therefore, the hourly cost used in this analysis is $80.00 ($169,091 per year).

PROPOSED CHANGES IN NOPR IN DOCKET NO. RM20–10–000—Continued

Area of modification A.	Number of respondents B.	Annual estimated number of responses per respondent C.	Annual estimated number of responses (Column B × Column C) D.	Average burden hours & cost per response E.	Total estimated burden hours & total estimated cost (Column D × Column E) F.
Total Proposed Changes for eTariff Filings (FERC–516):.	....	....	....	....	13,675 hours; $1,094,000.
Form 730					
Additional reporting requirements for current filers of FERC Form 730.	63	1	63	6 hours; $480	378 hours; $30,240.
Additional filers of FERC Form 730	137	1	137	36 hours; $2,880	4,932 hours; $394,560.
Sub-Total of Proposed Changes for Form 730.	....	....	....	....	5,310 hours; $424,800.
Total Proposed Changes for FERC–516 & Form 730 in NOPR in RM20–10.	....	....	....	....	18,985 hours; $1,518,800.

135. To date, the Commission has received approximately 110 incentive requests since Order No. 679 was issued in 2006. For the purposes of estimating burden in this NOPR, in the table above, we conservatively estimate annual numbers of the different possible incentive requests. We seek comment on the estimates in the table above regarding the number of incentive requests.

136. With regard to eTariff Filings, as discussed above, the Commission proposes to change its analysis and the regulatory text to implement a benefits-based standard. Rather than connecting incentives with risks and challenges, the Commission proposes that applicants demonstrate that facilities receiving incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent the requirements of section 219, and that the resulting rates are just and reasonable. Since applicants already seek incentives, we estimate that the additional burden to applicants to be in the demonstration of economic reliability benefits or reliability benefits for those associated incentives, the demonstration for transmission technology incentives, and the reporting related to the transmission technology incentives. We also note that the transmission planning regions will also have an additional burden in providing information to developers. For applicants in non-RTO regions, we seek comment on the additional estimates of burden these demonstrations and information sharing will require.

137. With regard to Form 730, the Commission estimates that the proposed changes will increase the amount of time required to prepare the information in Form 730 for public utilities that already report data by about 20 percent, from 30 hours to 36 hours, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The additional form preparation time data on prior spending and data on total projected spending on a project-by-project basis instead of as a total summation. It is the Commission's belief that public utilities are already gathering data in a project-by-project format to prepare the total summation in Table 1, so requiring a report on project-by-project spending would not require significant additional time.

138. Approximately 80 [147] transmission owners have requested transmission incentives and, therefore, only about 80 transmission owners have been subject to the requirement to file Form 730. We expect that requiring all transmitting utilities that receive the RTO-Participation Incentive for transmission projects that cost more than $3 million to report Form 730 will increase the number of utilities to about 150. Additionally, we conservatively estimate that, at any point in the future, the number of public utilities in non-RTO/ISO regions which may seek incentive requests to be about 50, leading to a conservative estimate of 200 transmission owners affected by the proposed changes to Form 730. We seek comment on the estimated additional burden and the number of transmission owners affected by the proposed changes to Form 730.

[147] The current OMB-approved inventory shows 63 respondents, so that figure is shown in the table above for the number of current filers (who will have an additional six hours of burden).

VI. Environmental Analysis

139. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[148] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classification, and services.[149]

VII. Regulatory Flexibility Act

140. The Regulatory Flexibility Act of 1980 [150] generally requires a description and analysis of proposed and final rules that will have significant economic impact on a substantial number of small entities. The Small Business Administration (SBA) sets the threshold

[148] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[149] 18 CFR 380.4(a)(15).

[150] 5 U.S.C. 601–612.

for what constitutes a small business. Under SBA's size standards,[151] RTOs/ISOs, planning regions, and transmission owners all fall under the category of Electric Bulk Power Transmission and Control (NAICS code 221121), with a size threshold of 500 employees (including the entity and its associates).[152]

141. The six RTOs/ISOs (SPP, MISO, PJM, ISO New England, NYISO, and CAISO) each employ more than 500 employees and are not considered small.

142. We estimate that 337 transmission owners and six planning authorities are also affected by the NOPR. Using the list of Transmission Owners from the NERC Registry (dated January 31, 2020), we estimate that approximately 68% of those entities are small entities.

143. We estimate additional annual costs associated with the NOPR (as shown in the table above) of:

- $480 each for 63 current filers of the Form FERC–730 and $2,880 each for 137 new filers of Form FERC–730
- $500 each for six RTO/ISO regions and six non-RTO/ISO regions to provide planning data (FERC–516)
- Costs ranging from $0 to $76,800 (for each transmission owner in RTOs/ISOs) to $112,000[153] (for each transmission owner in non-RTO/ISO regions) for eTariff filers (FERC–516). These costs are only incurred on a voluntary basis.

144. Therefore, the estimated additional annual cost per entity ranges from $0 to $114,880.

145. According to SBA guidance, the determination of significance of impact ''should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.''[154] We do not consider the estimated cost to be a significant economic impact. As a result, we certify that the proposals in this NOPR will not have a significant economic impact on a substantial number of small entities.

VIII. Comment Procedures

146. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due July 1, 2020. Comments must refer to Docket No. RM20–10–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

147. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

148. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426.

149. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

IX. Document Availability

150. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE, Room 2A, Washington, DC 20426.

151. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

152. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission. Commissioner Glick is dissenting in part with a separate statement to be issued at a later date.

Issued March 20, 2020.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend part 35, chapter I, title 18, Code of Federal Regulations, as follows.

Subpart G—Transmission Infrastructure Investment Provisions

■ 1. The authority citation for subpart G continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 41 U.S.C. 7101–7352.

■ 2. Section 35.35 is revised to read:

§ 35.35 Transmission infrastructure investment.

(a) *Purpose.* This section establishes rules for incentive-based rate treatments for transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

(b) *General rules.* (1) All rates approved under the rules of this section, including any revisions to the rules, are subject to the filing requirements of sections 205 and 206 of the Federal Power Act and to the substantive requirements of sections 205 and 206 of the Federal Power Act that all rates, charges, terms, and conditions be just and reasonable and not unduly discriminatory or preferential.

(2) All rates approved under the rules of this section are subject to a 250-basis-point cap on total return on equity incentives.

(3) Applicants for the incentive-based rate treatment must make a filing with the Commission under section 205 of the Federal Power Act prior to recovering incentives in rates.

(c) *Applications for incentive-based rate treatments for transmission infrastructure investment.* The Commission will authorize any incentive-based rate treatment, as discussed in this paragraph (c), for transmission infrastructure investment, provided that the proposed incentive-based rate treatment is just and reasonable and not unduly

[151] 13 CFR 121.201.

[152] The threshold for the number of employees indicates the maximum allowed for a concern and its affiliates to be considered small.

[153] These values represent the theoretical maximum case in which a Transmission Owner applies for every type of incentive, and also files a transmission technology annual report.

[154] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act,* at 18 (May 2012), *https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.*

discriminatory or preferential. An applicant's request for one or more incentive-based rate treatments, to be made in a filing pursuant to section 205 of the Federal Power Act, or in a petition for a declaratory order that precedes a filing pursuant to section 205 of the Federal Power Act, must include a detailed explanation of how the proposed rate treatment complies with the requirements of section 219 of the Federal Power Act and a demonstration that the proposed rate treatment is just, reasonable, and not unduly discriminatory or preferential. The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219 and that resulting rates are just and reasonable.

(d) *Types of incentive-based rate treatments for all transmission infrastructure investment.* For purposes of paragraph (c), incentive-based rate treatment means any of the following:

(1) A rate of return on equity sufficient to attract new investment in transmission facilities, including;

(i) 50-basis-points increase in return on equity incentives for ex-ante economic benefits;

(ii) 50-basis-points increase in return on equity incentives for ex-post economic benefits;

(iii) Up to 50-basis-points increase in return on equity incentives for reliability benefits;

(2) 100 percent of prudently incurred Construction Work in Progress in rate base;

(3) Recovery of prudently incurred pre-commercial operations costs;

(4) Hypothetical capital structure;

(5) Accelerated depreciation used for rate recovery;

(6) Recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the applicant;

(7) Deferred cost recovery; and

(8) Any other incentives approved by the Commission, pursuant to the requirements of this section, that are determined to be just and reasonable and not unduly discriminatory or preferential.

(e) *Incentive-based rate treatments for investment in transmission technology.* In addition to the incentives in § 35.35(d), the Commission authorizes the following incentive-based rate treatments and requirements for transmission technology investment by utilities that enhance reliability, economic efficiency, capacity, and improve the operation of new or existing transmission facilities:

(1) A stand-alone 100-basis-point return on equity incentive on the costs of the specified transmission technology project.

(2) Regulatory asset treatment for up to two years of initial costs related to deploying eligible transmission technologies that are traditionally expensed to be deferred and included in rate base for purposes of determining a public utility's rate of return, and amortized over five years.

(3) To be eligible to receive each incentive described in this subpart, each applicant must submit a transmission technology statement when requesting an incentive that demonstrates: how the technology meets the transmission technology criteria, the expected benefits of deployment, the cost of the transmission technology project, the cost of the overall transmission project if not a stand-alone transmission technology project, the expected useful life of the asset, and a demonstration that the transmission technology meets the economic benefits threshold.

(4) Eligible transmission technology pilot programs will receive a rebuttable presumption of eligibility for the incentives described in this subpart.

(5) Each applicant granted an incentive under this subpart must submit to the Commission an annual informational filing, for three years after the incentive is granted, that details the progress of the technology, obstacles to its deployment and efforts to overcome them, lessons learned, and any quantifiable data measuring the benefits of the transmission technology project. Any information already submitted to the Commission via existing forms need not be submitted under this requirement.

(f) *Incentives for joining and remaining in a Transmission Organization.* For purposes of this incentive, Transmission Organization means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities. The Commission will permit transmitting utilities or electric utilities that join a Transmission Organization the ability to recover prudently incurred costs associated with joining the Transmission Organization in their jurisdictional rates. Additionally, the Commission will authorize a 100-basis-point increase in return on equity as an incentive-based rate treatment for a transmitting utility that joins and remains in a Transmission Organization and turns over operational control of the applicant's wholesale transmission facilities to the Transmission Organization.

(g) *Approval of prudently-incurred costs.* The Commission will approve recovery of prudently-incurred costs necessary to comply with the mandatory reliability standards pursuant to section 215 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(h) *Approval of prudently incurred costs related to transmission infrastructure development.* The Commission will approve recovery of prudently-incurred costs related to transmission infrastructure development pursuant to section 216 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(i) *FERC–730, Report of transmission investment activity.* Public utilities that have been granted incentive rate treatment for specific transmission projects must file FERC–730 on an annual basis beginning with the calendar year incentive rate treatment is granted by the Commission. Such filings are due by April 18 of the following calendar year and are due April 18 each year thereafter. The following information must be filed:

(1) In dollar terms, on a project-by-project basis actual transmission investment for the most recent calendar year, and projected, incremental investments for the next five calendar years;

(2) For all current and projected investments over the next five calendar years, a project-by-project listing that specifies for each transmission project the most up-to-date, expected completion date, percentage completion as of the date of filing, and reasons for delays. Exclude from this listing transmission projects with projected costs less than $3 million that did not receive a project-specific transmission incentive; and

(3) For good cause shown, the Commission may extend the time within which any FERC–730 filing is to be filed or waive the requirements applicable to any such filing.

(j) *Rebuttable presumption.* (1) The Commission will apply a rebuttable presumption that an applicant has demonstrated that its project is needed to ensure reliability or reduces the cost of delivered power by reducing congestion for:

(i) A transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or

(ii) A transmission project that has received construction approval from an appropriate state commission or state siting authority.

(2) Effective date for abandoned plant costs: A public utility with a transmission project that is selected in a regional transmission planning process for the purposes of cost allocation can recover 100 percent of abandoned plant costs from the date such project is selected in a regional transmission planning process.

(3) To the extent these approval processes do not require that a project ensures reliability or reduce the cost of delivered power by reducing congestion, the applicant bears the burden of demonstrating that its project satisfies these criteria.

(k) *Commission authorization to site electric transmission facilities in interstate commerce.* If the Commission pursuant to its authority under section 216 of the Federal Power Act and its regulations thereunder has issued one or more permits for the construction or modification of transmission facilities in a national interest electric transmission corridor designated by the Secretary, such facilities shall be deemed to either ensure reliability or reduce the cost of delivered power by reducing congestion for purposes of section 219(a).

Note: The following appendices will not appear in the Code of Federal Regulations.

Appendix A—Benefit-Cost Data for Approved Economic Transmission Projects

TABLE 1—BENEFIT-COST RATIO SUMMARY

Average ratio calculations	Overall	>$25 million	<$25 million
All	*20.09*	*3.63*	*26.67*
PJM	35.12	4.95	38.30
CAISO	3.07	1.95	5.85
MISO	6.05	4.79	6.76
Total Projects	41.00	12.00	30.00

TABLE 2—BENEFIT-COST RATIO PERCENTILES

Percentile calculations	All	>$25 million	<$25 million
75th Percentile	15.21	3.98	33.91
90th Percentile	72.42	5.17	77.04

TABLE 3—ECONOMIC PROJECTS

[Project cost >$25 million]

Project	Region	Benefit	Cost ($)	Transmission planning cycle
Julian Hinds	CAISO	3.75	32,500,000	2018–2019
S-Line series reactor project *	CAISO	2.36	39,000,000	2018
East Marysville	CAISO	1.62	42,600,000	2018–2019
Delaney- Colorado River 500 kV line *(200 MW scenario)* **.	CAISO	0.94 (200 MW scenario) 1.10 (300 MW scenario)	501,000,000	2013–2014
Duff—Coleman 345 kV	MISO	15.80	49,600,000	2015
Southeast Louisiana Project	MISO	2.90	87,700,000	2016
Western Region Economic Project (WREP) (formerly known as East Texas Economic Project).	MISO	2.20	122,500,000	2015
Huntley—Wilmarth 345 kV	MISO	1.70	123,530,000	2016
Hartburg to Sabine Junction 500 kV Economic Project (Formerly WOTAB 500 kV Project).	MISO	1.35	158,520,000	2017
Conastone-Graceton (b2992)	PJM	5.23	39,600,000	2018
Market Efficiency Project 9A (b2743 & b2752)	PJM	4.67	320,190,000	2016

* *This project's benefit-cost ratio was determined to be encouraging, but CAISO earmarked it for future consideration once the design and configuration of this line is finalized. We included this project in our calculation because its ratio was deemed to be acceptable, and therefore, a valid data point for the purposes of contextualizing "selectable" B–C Ratios.*

** *CAISO calculated The Delaney-Colorado River 500 kV line's benefits included sensitivity analyses for both under 5% and 7% discount rates. We averaged the two sensitivity B–C ratios for each scenario, and present both instances here as sub-parts of one approved project.*

TABLE 4—ECONOMIC PROJECTS

Project cost >$25 million]

Project	Region	B–C Ratio	Cost	Transmission planning cycle
Giffen Line Reconductoring	CAISO	7.50	6,500,000	2018–2019
Lodi-Eight Mile 230 kV Line	CAISO	4.20	10,000,000	2014–2015
Carlyss 230–138 kV Autotransformer: Upgrade Station Equipment	MISO	28.25	670,000	2017
Upgrade Minden—Sarepta 115 kV Terminal Equipment	MISO	1.83	1,900,000	2016
Elkhart Lake SS, 138 kV—Relieve Market Congestion	MISO	3.55	2,540,000	2018
Sam Rayburn to Doucette 138 kV: Upgrade Line Rating	MISO	8.51	3,880,000	2017
Mabelvale-Bryant: Reconductor 115kV line	MISO	5.88	6,100,000	2015

TABLE 4—ECONOMIC PROJECTS—Continued

Project cost >$25 million]

Project	Region	B–C Ratio	Cost	Transmission planning cycle
Lakeover 500/230 kV XFMR	MISO	1.43	6,700,000	2016
Rebuild Wabaco to Rochester 161kV	MISO	6.79	12,960,000	2018
P3212: Wheatland to Breed 345 kV	MISO	1.28	14,500,000	2012
Wilson-BR Tap-Paradise 161 kV Modification	MISO	3.28	18,900,000	2018
Replace L7915 B phase line trap at Wayne substation	PJM	7.20	100,000	2015
Replace terminal equipment at Reynolds on the Reynolds—Magnetation 138kV.	PJM	120.83	120,000	2017
Replace relays at AEP's Cloverdale and Jackson's Ferry substations to improve the thermal capacity of Cloverdale—Jackson's Ferry 765 kV line.	PJM	15.80	500,000	2015
Upgrade 138 kV substation equipment at Butler, Shanor Manor and Krendale substations. New rating of line will be 353 MVA summer normal/422 MVA emergency.	PJM	35.80	600,000	2015
Upgrade capacity on E. Frankford-University Park 345kV	PJM	147.69	840,000	2017
Reconductor limiting span of Lallendorf—Monroe 345kV (crossing of Maumee river).	PJM	11.30	1,000,000	2017
Reconductor two spans of the Graceton—Safe Harbor 230 kV transmission line. Includes termination point upgrades.	PJM	4.30	1,100,000	2015
Rebuild Worcester—Ocean Pine 69 kV ckt. 1 to 1400A capability summer emergency.	PJM	82.70	2,400,000	2015
Reconductor three spans limiting Brunner Island—Yorkana 230 kV line, add 1 breaker to Brunner Island switchyard, upgrade associated terminal equipment.	PJM	73.30	3,100,000	2015
Upgrade terminal equipment on the Lincoln—Carroll 115/138 kV path	PJM	52.60	5,200,000	2015
Upgrade substation equipment at Pontiac Midpoint station to increase capacity on Pontiac-Brokaw 345 kV line..	PJM	13.45	5,620,000	2017
Reconductor Michigan City—Bosserman 138kV	PJM	4.93	6,000,000	2017
Reconductor Roxana—Praxair 138kV	PJM	1.07	6,100,000	2017
Reconfigure Munster 345kV as ring bus	PJM	4.78	6,700,000	2017
Rebuild the Hunterstown—Lincoln 115 kV line (No.962) (~2.6 mi.). Upgrade limiting terminal equipment at Hunterstown and Lincoln..	PJM	76.41	7,210,000	2019
Increase ratings of Peach Bottom 500/230 kV transformer to 1479 MVA normal/1839 MVA emergency.	PJM	2.60	9,700,000	2015
Reconductor approximately 7 miles of the Woodville—Peters (Z–117) 138 kV circuit.	PJM	5.80	11,200,000	2015
Mitigate sag limitations on Loretto—Wilton Center 345 kV Line and replace station conductor at Wilton Center.	PJM	64.46	11,500,000	2016
Rebuild Michigan City-Trail Creek—Bosserman 138 kV (10.7 mi)	PJM	2.63	24,690,000	2019

Appendix B

OMB Control Number: 1902–0239

Expiration Date: nn/nn/nnnn

Annual Due Date: April 18

FERC–730, Report of Transmission Investment Activity

Company Name: ____________________

To file this form, respondents should follow the instructions for eFiling available at *https://www.ferc.gov/docs-filing/efiling.asp.*

Template for Table 1

TABLE 1—ACTUAL AND PROJECTED ELECTRIC TRANSMISSION CAPITAL SPENDING BY PROJECT

Report year	Project code	Project description	Total actual and projected project spending on transmission facilities during each time period ($ Thousands) (1)								Notes
			Actual		Projected						
			Prior to report year	Report year +0	Report year +1	Report year +2	Report year +3	Report year +4	Report year +5	After Report year +5	
(2)	(3)	(4)	(5)	(6)	(7)					(8)	(9)

Instructions for completing ''Table 1'':

(1) Total Actual and Projected Project Spending on Transmission Facilities During Each Time Period is the total actual and projected spending on each project until it is completed. Transmission facilities are defined to be transmission assets as specified in the Uniform System of Accounts in account numbers 350 through 359 (*see,* 18 CFR part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* for account definitions). The Transmission Plant accounts include: Accounts 350 (Land and Land Rights), 351 (Energy Storage Equipment- Transmission), 352 (Structures and Improvements), 353 (Station Equipment), 354 (Towers and Fixtures), 355 (Poles and Fixtures), 356 (Overhead Conductors and Devices), 357 (Underground Conduit), 358 (Underground Conductors and Devices), and 359 (Roads and Trails).

(2) Report Year is the year associated with data reported in that row. For

example, if it is April 2021 and the public utility is reporting on 2020 project activity, the report year is 2020. A public utility can use the same form to correct a prior year's data. It would just report the data associated with the previous report year as an entry in Table 1.

(3) Project Code is the same Project Code associated with the project as in Table 2 below. Project Code is a 12-character alphanumeric string unique to each project. Respondents should add as many additional rows as are necessary to list all relevant projects. The combination of Report Year and Project Code is the primary key for each record. The primary key allows Table 1 and Table 2 data to be combined into a single table.

(4) Project Description is a descriptive name for the project. It is the same description associated with the project code in Table 2.

(5) Prior to the Report Year is the sum of all Actual spending associated with the project prior to the report year. All capital spending data is formatted as a currency number.

(6) Report Year +0 is the sum of all Actual spending associated with the project during the report year.

(7) Report Year +n means the sum of all Projected spending on the project in the calendar year of the Report Year plus n. For example, if n equals one, and the report year is 2020, then Report Year +1 will be 2021 and that entry would be sum of all Projected spending on the project in the calendar year 2021.

(8) After Report Year +5 means the sum of all Projected spending on the project more than five years past the Report Year. For example, if the report year is 2020, then this entry would be the sum of all spending starting at the beginning of 2026 and continuing until the project is complete. Note, that this entry can be estimated by using the total projected spending on the project, which the public utility already knows.

(9) Notes includes information about spending and estimated spending not included elsewhere. Notes is a 120-character string.

Below is an example of Table 1 associated with a fictitious public utility with two fictitious projects.

TABLE 1—ACTUAL AND PROJECTED ELECTRIC TRANSMISSION CAPITAL SPENDING BY PROJECT

Report year	Project code	Project description	Total actual and projected project spending on transmission facilities during each time period ($ thousands)								Notes
			Actual		Projected						
			Prior to report year	Report year +0	Report year +1	Report year +2	Report year +3	Report year +4	Report year +5	After report year +5	
2019	AKX0303	Piney Ridge to Fulton	$2,600	$28,500	$60,000 (10)	$60,000	$50,000	$0	$0	$0	Revision to 2019 actual.
2020	AKX0303	Piney Ridge to Fulton	$31,100	$30,500	$30,000	$40,000	$50,000	$40,000	$0	$0	Cost forecasts are higher and further out due to reroute.
2020	AKX0304	Fulton to Grey Pike	$1,100	$1,000	$36,000	$50,000	$20,000	$0	$0	$0	N/A.

(10) The developer should not revise projected data from what it originally reported unless the developer is correcting an obvious data entry mistake.

In this example, the public utility revised the 2019 data. The public utility cannot revise projected data; however, it is appropriate to revise actual data if that data has been reported incorrectly. For example, in 2020 the Prior to Report Year data for project code AKX0303 is $31.1 million. If the sum of Prior to Report Year and Report Year +0 for project code AKX0303 and report year 2019 did not sum to $31.1 million, then the public utility reported the data incorrectly in 2019 and should revise those entries.

Template for Table 2

TABLE 2—PROJECT STATUS DETAILS

Report year	Project code	Project description	Project voltage (kV)	Project type	Expected project completion date (month/year)	Completion status	Was project on schedule? (Y/N)	If project was not on schedule, indicate reasons for delay
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)

Instructions for completing ''Table 2'':

(1) Report Year is the year of the report data and should be the same as reported in Table 1. There should be no information in Table 2 that could not be known at the end of the report year.

(2) Project Code is a public utility-created alphanumeric designator twelve digits or less that is unique to each project. Project Code is the same project code from Table 1 above. Respondents must list all projects included in Table 1 that received a project-specific transmission incentive. Projects that only received the RTO-Participation Incentive need only be listed if they are projected to be at least $3 million. It can be identical to the code used by the RTO/ISO if it is unique to the project and is 12 digits or less. This code never changes during the time the project is developed and is never reused for any subsequent project. Respondents should add as many additional rows as are necessary to list all relevant projects. The combination of Report Year and Project Code is the primary key for each record. The primary key allows Table 1 and Table 2 data to be combined into a single table.

(3) Project Description is the same description used in Table 1 associated with the Project Code. Respondents should incorporate the name given by the public utility when requesting incentives into the Project Description, whenever possible. The Project Description never changes. Project Description is a 40-character string. Respondents must create a Project Description, using plain English, that will uniquely identify the project. The same Project Description cannot be used for two different Project Codes and each Project Code has only one Project Description ever.

(4) Project Voltage is the maximum voltage associated with the project. If no voltage could logically be associated the project, then respondents should enter a Project Voltage value of -9. Project Voltage is a numeric value so -9 is a way of indicating that there is no number for this entry.

(5) Respondents should select between the following Project Types to complete the Project Type column: New Build, Upgrade of Existing, Refurbishment/Replacement, or Generator Direct Connection. Project Type is a 40-character string.

(6) Expected Project Completion Date is the date the public utility forecasts as the date that the project will be completed at the end of Report Year. If the project was completed during the report year, then Expected Project Completion Date is the actual project completion date. Project Completion date is formatted mm/yyyy.

(7) Respondents should select between the following designations to complete the Completion Status column: Complete, Under Construction, Pre-Engineering, Planned, Proposed, and Conceptual. If the project is completed between the end of the report year and the day the public utility reports the data, the Completion Status would be Under Construction because that was the project status at the end of the report year. Completion Status is a 20-character string.

(8) Was Project on Schedule? (Y/N) is either Y (yes) or N (no) depending on whether the project was on schedule at the end of the report year. Was Project on Schedule? (Y/N) is a 1-character string.

(9) If the Project Was Not on Schedule, Indicate Reasons for the Delay is a 120-character string. The utility has 120 characters to explain why the project was delayed at the end of the report year. If there was no delay at the end of the report year, then the respondent can just enter N/A.

Below is an example of Table 2 associated with the same fictitious public utility with the same two fictitious projects as used in the example of Table 1.

TABLE 2—PROJECT STATUS DETAILS

Report year	Project code	Project name	Project voltage (kV)	Project type	Expected project completion date (month/year)	Completion status	Was project on schedule? (Y/N)	If the project was not on schedule, indicate reasons for the delay
2020 (10)	AKX0303	Piney Ridge to Fulton.	230	New Build	06/2024	Under Construction	No	Unable to site original route.
2020	AKX0304	Fulton to Grey Pike.	230	New Build	09/2023	Pre-Engineering	Yes	N/A.

(10) There is no revision for the 2019 AKX0303 Table 2 entry even though the public utility now knows that the route will be delayed because this information was not knowable at the end of the report year. Revisions to data are only to correct information that would have been known to be incorrect at the end of the report year.

Paperwork Reduction Act of 1995 (PRA) Statement: The PRA (44 U.S.C. 3501 *et seq.*) requires us to inform you the information collected in the Form 730 is necessary for the Commission to evaluate its incentive rates policies, and to demonstrate the effectiveness of these policies. Further, the Form 730 filing requirement allows the Commission to track the progress of electric transmission projects granted incentive-based rates, providing an accurate assessment of the state of the industry with respect to transmission investment, and ensuring that incentive rates are effective in encouraging the development of appropriate transmission infrastructure. Responses are mandatory. An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid OMB Control Number. Public reporting burden for reviewing the instructions, completing, and filling out this form is estimated to be 36 hours per response. Send comments regarding the burden estimate or any other aspect of this form to *DataClearance@FERC.gov,* or to the Office of the Executive Director, Information Clearance Officer, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426.

Title 18, U.S.C. 1001 makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious, or fraudulent statements as to any matter within its jurisdiction.

[FR Doc. 2020–06321 Filed 4–1–20; 8:45 am]

BILLING CODE 6717–01–P