can be found at: *http://www.ferc.gov/docs-filing/efiling/filing-req.pdf.* For other information, call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Dated: March 21, 2019.

**Nathaniel J. Davis, Sr.,**

*Deputy Secretary.*

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## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

**[Docket No. PL19–3–000]**

### Inquiry Regarding the Commission's Electric Transmission Incentives Policy

**AGENCY:** Federal Energy Regulatory Commission.

**ACTION:** Notice of inquiry.

**SUMMARY:** In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comments on the scope and implementation of its electric transmission incentives regulations and policy.

**DATES:** Initial Comments are due June 25, 2019, and Reply Comments are due July 25, 2019.

**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.

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**SUPPLEMENTARY INFORMATION:**

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1. In this Notice of Inquiry, the Commission seeks comment on the scope and implementation of its electric transmission incentives regulations and policy pursuant to section 1241 of the Energy Policy Act of 2005 (EPAct 2005),[1] codified as section 219 of the Federal Power Act (FPA),[2] which directed the Commission to use transmission incentives to help ensure reliability and reduce the cost of delivered power by reducing transmission congestion.[3] In 2006, the

[1] Energy Policy Act of 2005, Public Law 109–58, sec. 1261 *et seq.,* 119 Stat. 594 (2005).

[2] 16 U.S.C. 824s.

[3] The Commission is generally reevaluating its ROE policy in a separate Notice of Inquiry issued concurrently with this notice. *Inquiry Regarding the* Continued

Commission implemented section 1241 by issuing Order No. 679,[4] which established the Commission's basic approach to transmission incentives and enumerated a series of potential incentives that the Commission would consider. The Commission subsequently refined its approach to transmission incentives in a 2012 policy statement (2012 Incentives Policy Statement), which provided guidance on the Commission's interpretation of Order No. 679 and its approach toward granting transmission incentives, but did not alter the Commission's regulations or Order No. 679's basic approach to granting transmission incentives.

2. It has been nearly 13 years since the Commission promulgated Order No. 679 and nearly seven years since the Commission issued a policy statement to provide additional guidance regarding its evaluation of applications for transmission incentives under FPA section 219.[5] In that time, there have been a number of significant developments in how transmission is planned, developed, operated, and maintained. In light of those developments and the records compiled in various incentives proceedings before the Commission, we believe that it is appropriate to seek comment from stakeholders on the scope and implementation of the Commission's transmission incentives policy and on how the Commission should evaluate future[6] requests for transmission incentives in a manner consistent with Congress's direction in section 219. Accordingly, through this Notice of Inquiry, the Commission solicits comments on variety of issues related to transmission incentives policy, as discussed in the following sections.

## I. Background

### *A. FPA Section 219*

3. Prior to 2005, the Commission considered requests for certain transmission incentives pursuant to FPA section 205.[7] In 2005, Congress amended the FPA to, as relevant here, add a new section 219.[8] Section 219(a) ''directed FERC to promulgate a rule providing incentive-based rates for electric transmission for the purpose of benefitting consumers through increased reliability and lower costs of power.''[9] Section 219(b) included a number of specific directives in the required rulemaking, including that the Commission should:

- 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;[10]
- provide a return on equity that attracts new investment in transmission facilities, including related transmission technologies;[11]
- 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;[12] and
- allow the recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 of the FPA,[13] and all prudently incurred costs related to transmission infrastructure development pursuant to section 216 of the FPA.[14]

4. Section 219(c) requires 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[15] and ensure that any costs recoverable pursuant to this subsection may be recovered by such utility through the transmission rates charged by such utility or through the transmission rates charged by the Transmission Organization that provides transmission service to such utility.

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

### *B. Order Nos. 679 and 679–A*

6. On July 20, 2006, the Commission issued Order No. 679, fulfilling the rulemaking requirement in section 219(a). The Commission explained that, to receive an incentive, an applicant must satisfy the statutory threshold set forth in 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 the section 219(a) threshold and the nexus test were to be applied on a case-by-case basis.[16] In its discussion of the nexus test, the Commission explained 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.''[17]

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

- Adders to a base ROE: (1) To compensate for the risks and challenges of a specific transmission project (ROE adder for risks and challenges); (2) for forming a transmission-only company (Transco adder); (3) for joining a regional transmission organization (RTO) or independent system operator (ISO) (RTO/ISO adder); or (4) for use of an advanced transmission technology (technology adder);
- recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors that are beyond the control of the public utility (abandoned plant incentive);
- inclusion of 100 percent of construction work in progress (CWIP) in rate base (CWIP incentive);

*Commission's Policy for Determining Return on Equity,* 166 FERC ¶ 61,207 (2019). Below, *see infra* II.D.3, the Commission seeks comments regarding any interactions between the subject matters of these proceedings.

[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 Incentives Policy Statement).

[6] During the pendency of this proceeding, the Commission will continue to evaluate incentive requests under Order No. 679, as informed by the 2012 Incentives Policy Statement, on a case-by-case basis.

[7] 16 U.S.C. 824d; *see also Maine Public Utilities Commission* v. *FERC,* 454 F.3d 278, 288 (D.C. Cir. 2006).

[8] Energy Policy Act of 2005, Public Law 109–58, sec. 1241.

[9] *California Pub. Utilities Comm'n* v. *FERC,* 879 F.3d 966, 970 (9th Cir. 2018).

[10] 16 U.S.C. 824s(b)(1).

[11] *Id.* 824s(b)(2).

[12] *Id.* 824s(b)(3).

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

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

[15] The Commission defines a Transmission Organization as 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. 18 CFR 35.35(b)(2).

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

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

- 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).

8. On December 22, 2006, in Order No. 679–A, the Commission granted rehearing in part and denied rehearing in part of Order No. 679.[18] The Commission largely affirmed the conclusions discussed in the previous paragraphs while refining certain other aspects of Order No. 679.

*C. 2012 Policy Statement*

9. On November 15, 2012, the Commission issued a policy statement to provide additional guidance regarding its evaluation of applications for transmission incentives under section 219. In particular, the Commission reframed the nexus test for applicants seeking the ROE adder for risks and challenges and eliminated the technology ROE adder.[19] The Commission stated that it would expect an applicant seeking an ROE adder 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 risk-reducing 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.[20]

10. 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.[21]

*D. Order No. 1000*

11. 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 each public utility transmission provider amend its open access transmission tariff to describe procedures that provide for the consideration of transmission needs driven by public policy requirements in the local and regional transmission planning processes; (3) the elimination from Commission-approved tariffs and agreements a federal right of first refusal for certain new transmission facilities; and (4) coordination among neighboring transmission planning regions to identify potential interregional transmission facilities.[23]

12. The various regional transmission planning processes implemented in response to Order No. 1000 became effective between 2013 and 2015, after the Commission issued the 2012 Incentives Policy Statement. The transmission planning regions have all now conducted at least one iteration of their regional transmission planning process, with some having conducted as many as three. Although Order No. 1000 does not directly address the Commission's obligations under section 219, the aforementioned reforms had significant implications for how transmission facilities are planned and developed.

## II. Subject of the Notice of Inquiry

13. As part of ensuring that the Commission continues to meet our statutory obligations, the Commission, on occasion, engages in public inquiry to gauge whether there is a need to add to, modify, or eliminate certain policies or regulatory requirements. It has now been nearly 13 years since the Commission issued Order No. 679. During that time, the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably. Those changes include the Commission's issuance of Order No. 1000, an evolution in the generation mix and the number of new resources seeking transmission service, shifts in load patterns, and an increased emphasis on the reliability of transmission infrastructure. The Commission is issuing this NOI to obtain information that will assist us in evaluating our transmission incentives policy and ensuring that the policy continues to satisfy our obligations under section 219 of the FPA. The following sections present a series of questions regarding the Commission's transmission incentives policy. Commenters are encouraged to respond to these questions in detail and, where appropriate, provide specific examples to support their comments and recommendations. Commenters need not answer every question below.

*A. Approach to Incentive Policy*

14. The Commission in Order No. 679 established a requirement that each applicant demonstrate that there is a nexus between the incentive sought and the risks and challenges of the investment being made.[24] The Commission is considering whether the ''risks and challenges'' approach remains the most effective means of complying with Congress's directives in section 219. To that end, the Commission is seeking comments on how it should approach evaluating requests for incentives, including upon the current risks and challenges approach as well as upon other potential approaches, including, but not limited to, the alternative approaches discussed below. In addressing these approaches, commenters should consider how each approach could or should be implemented and the potential benefits and drawbacks of each approach.

1. Incentives Based on Project Risks and Challenges

15. As noted, the Commission in Order No. 679 established a requirement that each applicant must demonstrate that there is a nexus between the incentive sought and the risks and challenges of investment being made. Although the 2012 Incentives Policy Statement reframed this standard, it remains central to the Commission's approach in evaluating incentive applications.

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

[18] Order No. 679–A, 117 FERC ¶ 61,345.

[19] 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 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 23.

[20] *Id.* PP 20–28.

[21] *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.

[22] *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).

[23] *See* Order No. 1000, 136 FERC ¶ 61,051 at PP 4–6, 8.

[24] *See* Order No. 679, 116 FERC ¶ 61,057 at PP 26.

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

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

2. Incentives Based on Expected Project Benefits

16. The Commission could instead evaluate incentive requests based on the transmission project's potential to achieve benefits related to reliability and reductions in the cost of delivered power by reducing transmission congestion.[25]

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

(Q 5) If the Commission adopts a benefits approach, should it lay out general principles and/or bright line criteria for evaluating the potential benefits of a proposed transmission project? If so, how should the Commission establish the principles or criteria?

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

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

17. Although section 219 requires the Commission to consider performance-based ratemaking and to ensure that incentive-based rates are just and reasonable,[26] Congress did not require the Commission to base an incentive award on a specific level of benefits, either on its own or relative to the costs of the project(s) in question. Order No. 679 considered but rejected such a requirement.[27] The Commission is examining whether and how it might consider benefits relative to costs when evaluating a request for incentives.

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

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

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

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

3. Incentives Based on Project Characteristics

18. As an alternative to a direct examination of expected benefits, the Commission could use transmission project characteristics as a proxy for expected benefits. These project characteristics could include, for example, transmission projects located in regions with persistent needs, interregional transmissions projects, or transmission projects that unlock constrained resources. Such an approach could also consider granting incentives based upon inclusion of specific transmission technologies.[28]

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

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

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

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

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

*B. Incentive Objectives*

19. Prior to 2005, the Commission considered requests for certain transmission incentives pursuant to FPA section 205. As noted, section 219 directs the Commission to establish a transmission incentives policy that benefits consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[29] In addition, section 219 directs the Commission to promote certain specified goals—namely, promoting capital investment in the enlargement, improvement, maintenance, and operation of jurisdictional transmission facilities; providing an ROE that attracts investment in new transmission facilities and technologies; encouraging deployment of technologies and other measures that enhance the capacity, efficiency, and operation of existing transmission facilities; incentivizing transmission-owning public utilities to join an RTO; and allowing recovery of certain types of prudently incurred costs.[30]

20. This section seeks comment on what the Commission should incentivize in order to satisfy Congress's directives in section 219. In particular, we seek comment on what expected benefits or project characteristics warrant incentives. In discussing each benefit or project characteristic that the Commission should be incentivizing,

[25] Potential examples of these benefits and their potential relationship to types of transmission projects are described below in Section II.B.1–2.

[26] 16 U.S.C. 824s(a), (d).

[27] Order No. 679, 116 FERC ¶ 61,057 at P 65. The Commission notes that the 2012 Incentives Policy Statement directed applicants to limit ROE adder for risks and challenges to a cost estimate and demonstrate the use of risk reduction techniques. 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at PP 24, 28–29.

[28] Potential examples of these characteristics and their potential relationship to types of transmission projects are described below in Section II.B.3–12.

[29] 16 U.S.C. 824s(a).

[30] *Id.* 824s(b)–(c).

commenters should consider: (1) How the Commission should define the benefit or project characteristics in question; (2) whether the Commission can quantify or measure the benefits or project characteristics, where applicable, how it should do so; (3) how the Commission should incentivize the benefit or project characteristics if it decides to do so; and (4) the legal basis, extent, and nature of the incentives. For ROE adder incentives, the Commission is interested in how many basis points would be appropriate for a given incentive. The Commission is also interested in whether and how incentives other than ROE adders could encourage facilities with benefits or project characteristics, including those outlined below.

21. The sections below enumerate certain benefits or project characteristics that commenters may wish to address, although commenters need not limit their comments to these benefits or project characteristics. Commenters that choose to comment on the benefits and project characteristics discussed below should consider both the questions listed in the previous paragraph as well as the specific questions accompanying the following benefits or project characteristics.

1. Reliability Benefits

22. Benefitting customers by ensuring reliability was one of Congress's core objectives in section 219. Transmission owners are already required to address many facets of reliability through compliance with the North American Electric Reliability Corporation (NERC) reliability standards and various other planning criteria. Nevertheless, the Commission could potentially tailor incentives to promote reliability transmission projects that significantly enhance transmission reliability above and beyond what is required by the NERC reliability standards or other planning criteria.

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

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

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

23. One way in which additional transmission facilities may further encourage reliability is by expanding access to essential reliability services, which can, among other things, allow delivery of sufficient resources to support and stabilize grid frequency during disturbances and ensure adequate voltage control and reactive power capability.

(Q 20) Should the Commission incentivize transmission facilities that expand access to essential reliability services, such as frequency support, ramping capability, and voltage support?

(Q 21) If so, how should the Commission assess and measure whether transmission projects expand access to essential reliability services?

2. Economic Efficiency Benefits

24. Transmission projects can promote economic efficiency by reducing congestion, which allows efficient dispatch of resources, facilitating the interconnection of additional generation, and facilitating the transmission of additional generation to load centers.[31] The Commission could tailor incentives to promote transmission projects that accomplish either of these two outcomes.

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

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

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

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

3. Persistent Geographic Needs

25. Section 219's objective of promoting the development of transmission facilities that ensure reliability and/or reduce congestion may be particularly important in regions of the country that have experienced chronic, long-term congestion or require operating procedures in place to address long-term reliability issues.

(Q 26) Should the Commission utilize an incentives approach that is based on targeting certain geographic areas where transmission projects would enhance reliability and/or have particular economic efficiency benefits? If so, how should the relevant geographic areas be identified and defined? What entity (*e.g.,* the Commission, RTOs/ISOs, state regulators, other stakeholders) should designate such areas?

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

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

4. Flexible Transmission System Operation

26. As the generation mix changes and load patterns evolve, the requirements of the transmission system will also change. Flexibility characteristics of the transmission system, such as increased line rating precision, greater power flow control, and technologies, including energy storage,[32] may be able to facilitate the transmission system's ability to respond to changing circumstances.

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

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

(Q 31) How could the Commission define ''flexibility'' in this context?

5. Security

27. Enhancing the physical and cyber-security of existing jurisdictional transmission facilities, including new facilities, can improve the facilities' ability to contribute to the reliability of the bulk power system. Addressing the security of the transmission system is a priority of the Commission.[33]

[31] *See* Order No. 679, 116 FERC ¶ 61,057 at P 25; *see also* 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 21.

[32] *See W. Grid Dev., LLC,* 130 FERC ¶ 61,056, at PP 2, 43–46, *order denying reh'g,* 133 FERC ¶ 61,029 (2010).

[33] *See, e.g., Notice of Technical Conference,* AD19–12–000, at 1 (Feb. 4, 2019), and *Supplemental Notice of Technical Conference,* AD19–12–000, at 1 (Mar. 1, 2019); *Supply Chain Risk Management Reliability Standards,* Order No. 850, 83 FR 53992 (Oct. 26, 2018), 165 FERC ¶ 61,020 (2018); *Cyber Security Incident Reporting*

Continued

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

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

6. Resilience

28. The Commission has proposed 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.'' [34] So defined, enhancements to the resilience of the transmission system may enhance its overall reliability, potentially bringing investments in resilience within the Commission's mandate under section 219.

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

(Q 35) If so, how could the Commission consider or measure the benefits of an individual project towards grid resilience?

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

7. Improving Existing Transmission Facilities

29. Section 219(b)(3) directs the Commission to encourage investments in technologies and other measures that increase the capacity and efficiency of existing transmission facilities and improve the operation of those facilities.[35] Such investments could include advanced management software or application of technologies, such as energy storage, in order to improve utilization of existing transmission system assets.

(Q 37) How should the Commission incentivize the deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission grid? How can the Commission identify and quantify how a technology or other measure contributes to those goals? Please provide examples.

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

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

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

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

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

(Q 43) Should the Commission interpret section 219(b)(3) to encourage improvements that are not historically considered part of the transmission system, such as, for example, software upgrades, technologies that allow for faster ramping, or other innovative measures that achieve the same goals as new transmission facilities? What types of incentives could increase the adoption of these technologies? Are there forms of performance-based ratemaking with respect to transmission that the Commission should explore? If so, describe such alternative ratemaking structures.

8. Interregional Transmission Projects

30. An interregional transmission project [36] has the potential to improve interregional coordination, help to eliminate seams issues, and provide more efficient power flow among regions. Although Order No. 1000 required coordination among neighboring transmission planning regions to identify potential interregional transmission facilities, such projects have been scarce to date.

(Q 44) Should the Commission use incentives to encourage the development of interregional transmission projects? How, if at all, would any such incentive interact with Order No. 1000's reforms?

(Q 45) If the Commission should use incentives to encourage interregional transmission projects, should all interregional projects be eligible or should it be based on some other criteria? How should the Commission consider the benefits of an individual interregional transmission project?

(Q 46) If the Commission were to grant incentives for interregional transmission projects, what incentive(s) would be appropriate?

9. Unlocking Locationally Constrained Resources

31. The 2012 Incentives Policy Statement provided that ''projects that unlock location constrained generation resources that previously had limited or no access to the wholesale electricity markets'' may be eligible for incentives.[37] In subsequent years, interconnection queues in many regions of the country have expanded considerably, with many of the potential resources clustered in specific geographic areas with limited transmission access.[38]

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

(Q 48) If so, what metrics could the Commission consider when evaluating whether a transmission project

*Reliability Standards,* Order No. 848, 83 FR 36727 (July 31, 2018), 164 FERC ¶ 61,033 (2018); *see also Extraordinary Expenditures Necessary to Safeguard National Energy Supplies,* 96 FERC ¶ 61,299 (2001) (providing assurances, following the events of September 11, 2001, that the Commission will approve applications to recover prudently incurred costs necessary to safeguard the reliability and security of the nation's energy supply infrastructure).

[34] *Grid Reliability and Resilience Pricing and Grid Resilience in Regional Transmission Organizations and Independent System Operators,* 162 FERC ¶ 61,012, at P 23 (2018).

[35] 16 U.S.C. 824s(b)(3).

[36] Order No. 1000 defined an interregional transmission facility as one that is physically located in two or more neighboring transmission planning regions. Order No. 1000, 136 FERC ¶ 61,051 at P 63.

[37] 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 21.

[38] For instance, Midcontinent Independent System Operator, Inc., as of February 28, 2019, had 70.3 GWs of active projects in its interconnection queue. *See https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf.*

facilitates the interconnection of generation?

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

10. Ownership by Non-Public Utilities

32. Section 219(b)(1) encourages the Commission to facilitate capital investment in transmission infrastructure, regardless of the ownership of those facilities.

(Q 50) Are there barriers to non-public utilities' ownership of transmission facilities?

(Q 51) Should the Commission consider granting incentives to promote joint ownership arrangements with non-public utilities and, if so, how?

11. Order No. 1000 Transmission Projects

33. The Commission has considered whether it could reduce transmission developer risk by granting blanket pre-approval (*i.e.,* a rebuttable presumption) of three risk-reducing incentives for transmission projects selected in a regional transmission plan for purposes of cost allocation: CWIP, abandoned plant, and regulatory asset treatment.[39]

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

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

34. Following Order No. 1000, the Commission has exercised it discretion to grant certain incentives to non-incumbent transmission developers under section 205 of the FPA, in order to further the public policy goal of placing non-incumbent transmission developers on a level playing field with incumbent transmission owners in Order No. 1000 regional transmission planning processes.[40]

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

12. Transmission Projects in Non-RTO/ISO Regions

35. Applications for transmission incentives to date have almost exclusively been for transmission projects proposed to be developed within RTOs/ISOs.

(Q 55) Are there factors that discourage developers of transmission projects in non-RTO/ISO regions from seeking incentives?

(Q 56) What, if any, additional types of incentives could appropriately encourage the development of transmission in non-RTO/ISO regions?

*C. Existing Incentives*

36. The Commission also seeks comment on the types of incentives that it has awarded to date, including ROE adder incentives based on risks and challenges, discussed above. Commenters should address whether the incentive itself remains relevant and appropriate. In addition, commenters should consider whether the goals underlying the incentive could be incentivized more efficiently. For example, if an incentive is currently awarded as ROE basis point adder, Commenters should also address whether a non-ROE incentive would be more appropriate. Although we invite comment on all current incentives, we specifically seek comment on the following incentives.

1. ROE-Adder Incentives

a. Transmission-Only Companies

37. In Order No. 679, the Commission found that transmission-only companies (*i.e.,* Transcos) warranted incentives because they were willing and able to invest in transmission based on a proven and encouraging track record of existing Transcos' investment in transmission infrastructure and their expansion plans. The Commission explained that this record of investment was due to the stand-alone nature of these entities—''[b]y eliminating competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed.''[41] Further, the Commission found that ''Transcos have no incentive to maintain congestion in order to protect their owned generation''; ''Transcos' for-profit nature, combined with a transmission-only business model, enhances asset management and access to capital markets and provides greater incentives to develop innovative services''; and due to ''their stand-alone nature, Transcos also provide non-discriminatory access to all grid users,'' and supported regional planning goals.[42] In subsequent decisions regarding the Transco adder, the Commission has addressed challenges presented by maintaining an appropriate threshold for eligibility with respect to necessary independence.[43]

(Q 57) Does the Transco business model continue to provide sufficient benefits to merit transmission incentives? What information should an entity seeking a Transco incentive provide to demonstrate sufficient benefits?

(Q 58) Should the Transco incentive remain available to Transcos that are affiliated with a market participant? If so, how should the Commission evaluate whether a Transco is sufficiently independent to merit an incentive?[44]

(Q 59) Should a Transco incentive be awarded on a project-by-project basis?

(Q 60) Should the Transco incentive exclude assets that a Transco buys, rather than develops?

b. RTO/ISO Participation

38. Section 219(c) requires that the Commission provide incentives to transmitting utilities or electric utilities that join an RTO or ISO. In Order No. 679, the Commission found that ROE incentives should be granted to utilities that ''join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization.''[45] The Commission declined to make a finding on the appropriate size or duration of the

[39] *See Notice Inviting Post-Technical Conference Comments,* Docket No. AD16–18–000, at 2 (Aug. 3, 2016).

[40] *See, e.g., PJM Interconnection, L.L.C.,* 155 FERC ¶ 61,097, at P 175 (2016), *order on reh'g,* 158 FERC ¶ 61,060 (2017); *ATX Sw., LLC,* 152 FERC ¶ 61,193, at PP 18, 23 (2015); *Transource Kan., LLC,* 151 FERC ¶ 61,010, at P 19 (2015), *order on reh'g,* 154 FERC ¶ 61,011, at P 12 (2016), *petition dismissed sub nom, Kan. Corp. Comm'n* v. *FERC,* 881 F.3d 924 (D.C. Cir. 2018); *Xcel Energy Sw. Transmission Co., LLC,* 149 FERC ¶ 61,182, at P 33 (2014).

[41] Order No. 679, 116 FERC ¶ 61,057 P 224.

[42] *Id.* PP 224–227.

[43] *See, e.g., Consumers Energy Co.* v. *Int'l Transmission Co.,* 165 FERC ¶ 61,021, at PP 67–73 (2018) (reducing a previously granted Transco ROE adder due to reduced independence); *NextEra Energy Transmission N.Y. Inc.,* 162 FERC ¶ 61,196, at PP 51–52 (2018) (finding that the applicants relationship with affiliated market participants did not prevent it from meeting the independence standard for a Transco).

[44] *C.f. Consumers Energy Co.* v. *Int'l Transmission Co.,* 165 FERC ¶ 61,021 at PP 67–74 (granting a complaint in part to reduce Transco adders based upon the Commission's finding that the Transco was now less independent).

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

incentive.[46] Subsequently, the U.S. Court of Appeals for the Ninth Circuit found that the Commission's granting of an RTO participation incentive to Pacific Gas and Electric Co. (PG&E) was arbitrary and capricious in its application of Order Nos. 679 and 679–A because the Commission failed to provide a reasoned explanation for granting the incentive in light of the Commission's longstanding policy that incentives should only be granted to induce future behavior.[47]

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

(Q 62) Should the Commission consider providing incentives other than ROE adders for utilities that join RTO/ISOs, such as the automatic provision of CWIP in rate base or the abandoned plant incentive [48] for all transmission-owning members of an RTO/ISO? If so, what other types of incentives would be appropriate?

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

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

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

(Q 66) In Order No. 679, the Commission found that ''the basis for the incentive is a recognition that benefits flow from membership in such organizations and the fact that continuing membership is generally voluntary.'' [49] Should voluntary participation remain a requirement for receiving RTO/ISO incentives?

c. Advanced Technology

39. Order No. 679, the Commission considered the use of advanced technologies (1) as part of an overall nexus, accounting for risks and challenges, and (2) where an applicant sought a stand-alone incentive ROE adder based on advanced technology utilization. The Commission discontinued a stand-alone advanced transmission technologies incentive in the 2012 Incentives Policy Statement, but concluded that some transmission enhancement projects might represent good candidates for an ROE adder for risks and challenges.[50] To date, there have been few applications seeking an ROE adder related to advanced technology.

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

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

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

2. Non-ROE Transmission Incentives

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

40. In Order No. 679, the Commission recognized that some transmission incentives—such as including 100 percent of CWIP in rate base and recovery of 100 percent of pre-commercial costs as an expense or as a regulatory asset—reduce the financial and regulatory risks associated with transmission investment.[51]

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

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

b. Hypothetical Capital Structure

41. A hypothetical capital structure can serve as an incentive by providing cash flow predictability and a higher rate of return where public utilities have a higher amount of debt than in the hypothetical capital structure. The Commission largely relies on a public utility's actual capitalization in setting its rate of return, but recognized in Order No. 679 that an overly rigid approach to evaluating a proposed capital structure could be a disincentive to investment in new transmission projects.[52] Accordingly, the Commission allows applicants to file an overall rate of return based on a hypothetical capital structure, and gives them the flexibility to refinance or employ different capitalizations as may be needed to maintain the viability of new capacity additions. The Commission currently approves hypothetical capital structures during the construction period, chiefly for small or new transmission owners for which the new transmission project would cause substantial fluctuations in their capital structure during construction. The Commission has allowed a hypothetical capital structure to extend for the life of the transmission project for non-public utilities without traditional capital structures.

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

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

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

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

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

c. Recovery of the Cost of Abandoned Plant

42. Even prior to Order No. 679, the Commission granted recovery of 100 percent of the prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility (the abandoned plant incentive) as a way of mitigating certain risks that are

[46] *Id.* P 331.

[47] *Cal. Pub. Util. Comm'n* v. *FERC,* 879 F.3d at 974–75, 977; *see also Pacific Gas and Electric Co.,* 164 FERC ¶ 61,121 (2018) (establishing a briefing schedule to supplement the record on the specific questions raised on remand).

[48] The abandoned plant incentive allows recovery of 100 percent of the prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility.

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

[50] 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 21 & nn.27–28.

[51] These incentives have routinely been granted to applicants who do not yet have customers from which to recover pre-commercial costs, including costs associated with Order No. 1000 proposals by nonincumbent transmission developers. The Commission has reasoned that doing so is necessary to level the playing field with incumbent transmission owners, who can already recover such costs from ratepayers. *See Ne. Transmission Dev., LLC,* 155 FERC ¶ 61,097, at P 41 (2016), *order on reh'g,* 158 FERC ¶ 61,060 (2017); *Xcel Energy Sw. Transmission Co., LLC,* 149 FERC ¶ 61,182 at P 33.

[52] Order No. 679, 116 FERC ¶ 61,057 at PP 123, 131.

outside the control of the developer.[53] Order No. 679 stated that transmission developers may be entitled to recover 100 percent of the prudently incurred costs related to certain transmission facilities if such facilities are later abandoned or cancelled.[54]

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

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

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

d. Accelerated Depreciation

43. In Order No. 679, the Commission included accelerated depreciation as a potential transmission incentive reasoning that this incentive increases cash flow, providing an incentive to undertake transmission projects.

(Q 80) Should the Commission continue to consider accelerated depreciation as an incentive?

(Q 81) Does the accelerated deprecation incentive provide meaningful benefits to transmission developers?

(Q 82) Should the Commission grant an accelerated depreciation incentive with a generic depreciation period or continue to determine such a period on a case-by-case basis?

*D. Mechanics and Implementation*

1. Duration of Incentives

44. The Commission is considering whether incentives should be revisited if there is a material modification to the project or a significant change in the expected benefits. Please comment on whether particular types of incentives should automatically sunset and under what certain circumstances.

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

(Q 84) How should the Commission structure a durational component to its incentives? For example, should the Commission provide that transmission incentives automatically sunset after a certain period?[55]

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

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

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

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

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

2. Case-by-Case vs. Automatic Approach in Reviewing Incentive Applications

45. In Order No. 679, the Commission stated that the section 219(a) threshold that a transmission project must ensure reliability or reduce the cost of delivered power by reducing transmission congestion and the nexus test are not prescriptive by design, and are intended to be applied on a case-by-case basis.

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

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

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

3. Interaction Between Different Potential Incentives in Determining Correct Level of ROE Incentives

46. In determining whether an applicant has satisfied the nexus test, the Commission evaluates the interrelationship between the requested incentives.[56] The Commission, however, to date has provided limited guidance regarding what level of transmission incentives should be provided or how to ensure that the combination of transmission incentives provided is appropriate and produces rates that are just and reasonable.[57]

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

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

(Q 95) The Commission's current policy is that the total ROE may not exceed the zone of reasonableness. If a transmission project qualifies for ROE incentives, should there be an upper limit or range that the total ROE cannot exceed? If so, what is the appropriate limit or range? Should this vary based on how the Commission sets base ROE?[58]

4. Bounds on ROE Incentives

47. The benefits of various transmission projects may vary substantially and, in some cases, be difficult to compare. Particularly given the current risks and challenges framework, the Commission has maintained discretion to determine the level of any granted incentive ROE rather than establishing pre-determined levels or ranges for incentive ROEs.

(Q 96) For ROE incentives, to what extent, if any, should the Commission retain discretion to determine the appropriate level of ROE incentives?

(Q 97) If the Commission retains discretion with respect to determining ROE incentives, should its discretion be bound within a pre-determined range

[53] *See* Order No. 679, 116 FERC ¶ 61,057 at P 156 (explaining that the Commission's proposed change in policy was an extension of the Commission's decision in *S. Cal. Edison Co.,* 112 FERC ¶ 61,014, *reh'g denied,* 113 FERC ¶ 61,143 (2005)).

[54] *Id.* P 163.

[55] For example, the incentive for joining an RTO/ISO or forming a Transco could be limited to a set number of years.

[56] Order No. 679–A, 117 FERC ¶ 61,345 at P 21.

[57] An exception, as noted, is that the Commission has required applicants to seek to employ risk reducing incentives before they seek an ROE adder for risks and challenges. *See* 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at PP 24, 28–29.

[58] The Commission has proposed a methodology for base ROE and established a paper hearing proceeding on whether and how this methodology should apply. *See Martha Coakley* v. *Bangor Hydro-Elec. Co.,* 165 FERC ¶ 61,030 (2018); *Ass'n of Businesses Advocating Tariff Equity* v. *Midcontinent Indep. Sys. Operator, Inc.,* 165 FERC ¶ 61,118 (2018).

(*e.g.,* between 50 and 100 basis points)? If so, what is the appropriate range and why?

*E. Metrics for Evaluating the Effectiveness of Incentives*

48. The Commission has a ''longstanding policy that incentives should only be awarded to induce voluntary conduct.'' [59] Nevertheless, it can sometimes be difficult to identify the extent to which a particular incentive motivates a transmission developer to take a particular action. Order No. 679 adopted an annual reporting requirement, Form FERC–730, which requires transmission incentives recipients to provide limited information.[60] Additional transmission incentive-related data, beyond that available under the Commission's existing reporting standards or through other public sources, could help the Commission to better understand the effectiveness of the incentives program, including the effects of any changes that it adopts through this proceeding. In particular, a standard of comparison among transmission projects, regardless of whether a project receives incentives and/or ultimately goes into service, would allow the Commission to examine whether incentives motivate investment in and development of new transmission projects.

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

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

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

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

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

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

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

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

**III. Comment Procedures**

49. The Commission invites interested persons to submit comments on the matters and issues proposed in this Notice of Inquiry, including any related matters or alternative proposals that commenters may wish to discuss. Initial Comments are due June 25, 2019, and Reply Comments are due July 25, 2019. Comments must refer to Docket No. PL19–3–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

50. 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.

51. 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.

52. 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.

**IV. Document Availability**

53. 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.

54. 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.

55. 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.*

By direction of the Commission.

Issued: March 21, 2019.

**Nathaniel J. Davis, Sr.,**

*Deputy Secretary.*

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[59] *Cal. Pub. Util. Comm'n* v. *FERC,* 879 F.3d at 978.

[60] Order No. 679, 116 FERC ¶ 61,057 at P 367. FERC–730 requests information concerning: (1) The transmission developer's actual capital spending on each transmission project for which it has received incentives, as well as its projected capital spending on the projects for the next five years; (2) a high-level description of such projects, including their voltage level; (3) the type of transmission project (*i.e.,* whether it is new build, an upgrade to existing infrastructure, a refurbishment/replacement, or a generator direct connection); (4) each project's completion status (*i.e.,* complete, under construction, pre-engineering, planned, proposed, or conceptual); and (5) each project's estimated completion date, as well as the reason for any delays (*i.e.,* siting, permitting, construction, delayed completion of new generator, or other).

## DEPARTMENT OF ENERGY

### Federal Energy Regulatory Commission

**[Project No. 14861–001]**

### FFP Project 101, LLC; Notice of Intent To File License Application, Filing of Pre-Application Document, and Approving Use of the Traditional Licensing Process

a. *Type of Filing:* Notice of Intent to File License Application and Request to Use the Traditional Licensing Process.

b. *Project No.:* 14861–001.

c. *Date Filed:* January 28, 2019.

d. *Submitted By:* Rye Development on behalf of FFP Project 101, LLC.

e. *Name of Project:* Goldendale Pumped Storage Project.

f. *Location:* Off-stream (north side) of the Columbia River at River Mile 215.6