UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF EXELON CORPORATION

Exelon Corporation (Exelon) appreciates the opportunity to submit comments in response to the Federal Energy Regulatory Commission's (Commission) Notice of Inquiry Regarding the Commission's Electric Transmission Incentives Policy.[1] Transmission infrastructure investments (even those that are routine) provide a range of benefits to customers, including improved reliability, enhanced system resilience, reduced transmission congestion, and greater access to new resources. Thus, it is reasonable for the Commission to periodically reassess its framework for evaluating transmission incentives to ensure that it effectively supports such investment, especially as transmission technologies change and system needs evolve.

That said, Exelon believes that the Commission can best support such investments not through initiatives to create new additional incentives for specific types of transmission projects (as the Commission seems to be undertaking through this NOI), but rather by providing regulatory certainty that will encourage transmission development through fair, timely, and flexible performance of its statutory duties in the ordinary course of business. Dedicating time and resources to develop and implement additional new transmission incentives for specific

---

[1] *Inquiry Regarding the Commission's Electric Transmission Incentives Policy*, Notice of Inquiry, 166 FERC ¶ 61,208 (2019) (Incentives NOI).

transmission project types will incent only limited new investment and, more importantly, may distract resources from ensuring the regulatory certainty needed to support other more routine, but nonetheless important, transmission investments. Exelon respectfully submits that the Commission could more effectively support beneficial and needed transmission investment by refocusing its efforts on timely and fairly acting on the routine rate filings that utilities make to recover the costs of such investments and being more flexible in its implementation of current incentive policies by modifying its existing framework for evaluating certain types of incentive applications.

I. INTRODUCTION

On March 21, 2019, the Commission issued the Incentives NOI, setting forth a range of questions on the scope and implementation of its electric transmission incentives regulations and policies.[2] The topics addressed in the questions include (1) the Commission's framework for evaluating incentive applications, (2) the potential for granting incentives based on project benefits or characteristics, (3) different categories of benefits that may merit incentives, (4) the continued value of existing incentives, (5) the mechanics and implementation of the Commission's incentive policy framework, and (6) metrics for evaluating the effectiveness of incentives.

As transmission owners and electric transmission service customers, Exelon and its subsidiaries have a substantial interest in this proceeding. Exelon is a holding company, headquartered at 10 South Dearborn Street, Chicago, Illinois, with operations and business activities in 48 states, the District of Columbia, and Canada. Exelon owns Atlantic City Electric

[2] Incentives NOI, 166 FERC ¶ 61,208 at P 1.

Company (Atlantic City Electric), Baltimore Gas and Electric Company (BGE), Commonwealth Edison Company (ComEd), Delmarva Power & Light Company (Delmarva Power), PECO Energy Company (PECO), and Potomac Electric Power Company (Pepco). Together Atlantic City Electric, BGE, ComEd, Delmarva, PECO, and Pepco own electric transmission and distribution systems that deliver electricity to approximately 10 million customers in the District of Columbia (Pepco), northern Delaware and the Delmarva Peninsula (Delmarva Power), southern New Jersey (Atlantic City Electric), Northern Illinois (ComEd), Maryland (BGE and Pepco), and southeastern Pennsylvania (PECO). Exelon Generation Company (ExGen) is one of the largest competitive power generators in the U.S., with approximately 33,000 megawatts of owned capacity comprising one of the nation's cleanest and lowest-cost power generation fleets, located in a number of organized markets. Constellation, an ExGen business unit consisting of subsidiaries and divisions of ExGen, is one of the nation's leading marketers of electricity and natural gas and related products in wholesale and retail markets.

Below, Exelon offers comments on a number of the questions included in the Incentives NOI.[3]

II. COMMENTS

A. Enhanced Regulatory Certainty Will Support Transmission Development More than Additional New Incentives

At its core, transmission investment is driven by the benefits that a robust transmission system provides to customers. Society depends on reliable and affordable electric service; it is

[3] We do not provide responses to every question, but reserve the right to comment on these issues in this and future proceedings. Moreover, silence on a particular issue does not indicate agreement with the propositions set forth in any of the questions.

essential to our health, security, prosperity, and comfort. Adequate investment in transmission infrastructure is key to the continued provision of that service to our customers. For example, investments to replace and upgrade existing transmission infrastructure are becoming increasingly important to maintaining reliable service as our nation's transmission system ages and the demands placed on it evolve.[4] Investments in new transmission facilities and upgrades to existing transmission facilities to enhance the reliability and resilience of the transmission system provide better service to customers, reducing the frequency and duration of outages and hardening the system against a range of threats (e.g., severe weather and physical and cyber security threats). Such investments can also reduce congestion, facilitating the delivery of lower cost power to loads.[5] Moreover, transmission investments can support a range of public policy goals, including greater access to location-constrained intermittent, renewable resources[6] and emissions reductions.[7] And these benefits will likely increase as our electricity system evolves – indeed, a robust, flexible, and smarter transmission system will be increasingly necessary to support our nation's transition towards the grid of the future, including greater electrification of the transportation industry (among other sectors), microgrids, and increased penetration of distributed energy resources.

---

[4] In PJM, nearly two-thirds of all transmission system assets are more than 40 years old; over one-third are more than 50 years old. *The Benefits of the PJM Transmission System*, PJM Interconnection, L.L.C., at 5, 55-56 (Apr. 16, 2019), https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.ashx?la=en (PJM Transmission System Benefits Report). Replacing and modernizing these assets has a number of benefits for customers, including lower maintenance costs, reduced risk of outages associated with deteriorating transmission facilities, and the deployment of more technologically advanced equipment that has greater capabilities than the equipment it replaces. *Id.* at 55.

[5] *See Id.* at 49-52. As PJM explains in its report, a robust transmission system not only facilitates more economic power transfers within regions, but also between regions.

[6] *See Id.* at 30-33.

[7] *See Id.* at 33-34.

The need for continued investment in transmission infrastructure is clearly essential, and in the Incentives NOI, the Commission seeks comment on how it can revise its incentive policies to best support such investment. Exelon appreciates the Commission's interest in ensuring that its policies are effective and seeking potential additions and alternatives, but we respectfully submit that the Commission's existing incentive policies are generally working. Combined with sensible and timely-administered Commission policies on cost recovery, these existing incentive tools (with some refinement, as discussed in sections II.B.2.a and II.D.2.a below) can motivate and ensure sufficient transmission investment.

So long as the existing incentives program is maintained, there is no need to develop new incentives that could have the perverse effect of undermining needed and beneficial transmission investment. Focusing on new incentives to support additional investment in specific types of transmission projects could distract from the policies needed to support other transmission investments, driving the Commission and utilities to shift their priorities accordingly. As a result, such incentives could undermine utilities' efforts to strengthen and improve their transmission systems based on the unique challenges that they each face. Moreover, expending considerable effort to develop specific new incentives will take time and resources that could instead be engaged in refining the Commission's existing framework for evaluating incentives, as warranted, and may divert attention from the importance of meeting the foundational, day-to-day needs of the grid. Any new incentives developed would only apply in limited situations, resulting in infrequent utilization; the Commission's limited resources would be better spent on modifying its existing framework for evaluating incentive applications to account for additional benefits (as discussed in section II.B.2.a below).

To better support needed and beneficial transmission investment, the Commission should focus in the first instance on providing regulatory certainty through fair, timely, and flexible consideration of filings in its ordinary course of business. As Exelon explained in its comments in response to the Commission's March 28, 2019 joint technical conference with the Department of Energy,[8] the Commission can provide this needed regulatory certainty by applying the following five key ratemaking principles: (1) timely and fair consideration of any proposed changes to rates and rate structures, (2) certainty about the Commission's ROE policies, (3) continued availability of the RTO Participation Adder and existing risk-reducing incentives, (4) flexibility in the Commission's implementation of its policies to reflect technological changes, emerging threats, and evolving reliability standards, and (5) acknowledgement of the value to customers of transmission investments to provide greater reliability and resilience than addressed by mandatory reliability standards. We discuss each principle below in turn, except for principle (2), which we discuss at length in our comments in response to the Commission's Notice of Inquiry Regarding the Commission's Policy for Determining Return on Equity (ROE Policy NOI).[9]

First, the Commission should ensure that utilities have the opportunity to recover the costs of their transmission investments by acting timely and fairly on their proposals to change their rates or rate structures. As a general rule, utilities are investing in the transmission infrastructure needed to fulfill the objectives of Federal Power Act (FPA) section 219 – they plan

---

[8] *See Exelon Corporation*, Post-Technical Conference Comments of Exelon Corporation at 4-14, Docket No. AD19-12 (filed May 28, 2019) (Exelon Physical and Cyber Security Post-Technical Conference Comments).
[9] See *Exelon Corporation*, Comments of Exelon Corporation, Docket No. PL19-4 (filed Jun. 26, 2019) (ROE Policy NOI Comments). The Commission issued the ROE Policy NOI concurrently with the Incentives NOI. *See Inquiry Regarding the Commission's Policy for Determining Return on Equity*, Notice of Inquiry, 166 FERC ¶ 61,207 (2019).

their everyday investments to do just what the statute seeks to incent: benefit consumers by ensuring reliability and reducing the cost of delivered power.[10] But they can only continue to make these investments if they have a reasonable opportunity to recover their costs, an opportunity that requires timely and fair Commission action on rate-related filings. Prolonged regulatory proceedings and specific Commission decisions that undermine the ability of utilities to recover their costs can increase the risks that they face,[11] hindering investment. This uncertainty is particularly damaging where the scope of issues subject to hearing or further regulatory process is wider than the modifications that a utility has proposed to its rate,[12] which discourages utilities from filing to adopt new rate structures and cost recovery mechanisms to support their investments.

Second, the Incentives NOI has created uncertainty that could discourage investment, unsettling utilities' (and, importantly, investors') expectations. It calls into question the continued availability of transmission incentives that have significantly supported transmission infrastructure development, including the RTO Participation Adder and the risk-reducing incentives (such as the abandoned plant incentive). As Exelon explains in section II.D.1.a below, the Commission should affirm the continued availability of the RTO Participation Adder

---

[10] 16 U.S.C. § 824s(a) (2012).
[11] *See, e.g., Commonwealth Edison Company*, 164 FERC ¶ 61,172 (2018) (rejecting the Exelon Companies' proposals to provide a mechanism to refund or recover, as appropriate, certain deferred income tax excesses and deficiencies that they previously recorded on their books and that they will record on an ongoing basis); *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,163 (2017), affirmed and clarified, *PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,173 (2018). *See also, Commonwealth Edison Company,* Deficiency Letter, Docket No. ER19-5 et al. (Nov. 21, 2018); *Commonwealth Edison Company,* Deficiency Letter, Docket No. ER19-5 et al. (Jan. 28, 2019); *Commonwealth Edison Company*, 167 FERC ¶ 61,071 (2019) (setting the filings for hearing and settlement judge procedures).
[12] *See, e.g., PJM Interconnection L.L.C.*, 167 FERC ¶ 61,192 (2019) (setting for hearing and settlement judge procedures issues beyond those that were included in the proposed formula rate revisions, which would have better aligned incurrence and recovery of Pepco's transmission costs).

because it reflects the benefits that regional transmission organization/independent system operator (RTO/ISO) participation provides to customers and compensates utilities for the risks that membership entails. It should also retain the existing risk-reducing incentives, which provide customer benefits by mitigating some of the risks that are inherent in developing certain transmission projects, reducing financing costs and facilitating investment in transmission facilities that are beneficial and needed but difficult to develop. These incentives are particularly helpful when a utility does not have the option to forgo such projects, such as when an RTO/ISO or relevant regulatory authority directs it to build a transmission project (see section II.D.2.a below on the abandoned plant incentive).

In addition, the Commission should be flexible when applying its existing policies to support transmission investments that reflect technological changes, emerging threats, and evolving reliability standards. At first consideration, flexibility may not seem to promote regulatory certainty – it allows the Commission to exercise its discretion based on the specific facts and circumstances of each case. But in fact, flexibility will better support the development of beneficial transmission infrastructure by allowing the Commission to react to changes in the electric industry without continually revisiting and reworking its policies, providing greater regulatory certainty in the long term and helping to ensure that the Commission does not inadvertently create barriers to innovative transmission technologies and solutions.

For example, the Commission demonstrated such flexibility when approving ComEd’s recent request to functionalize ComEd’s Superconductor Project (which will operate at 12 kV) as transmission given that it will serve a transmission function (i.e., is a high capacity facility that will convert two substations from radial feeders into a looped network, providing for bidirectional flows and voltage support and relief from thermal overloads).[13] By doing so, the Commission is facilitating ComEd's deployment of its first-of-a-kind Superconductor Project, which will deploy an advanced technology (high temperature superconducting cables) to form a new looped transmission path in a dense urban area where adding conventional high-voltage conductors would be impractical (if not impossible), enhancing the reliability and resilience of ComEd's system in downtown Chicago.[14] In that same order, the Commission also granted ComEd's request for the abandoned plant incentive for the project, finding that it reflects an innovative use of an advanced technology, but will likely create unique and special challenges for ComEd with risk factors beyond the company's control.[15] The Commission should continue to be flexible when evaluating new proposals and filings (including requests to functionalize unconventional transmission assets as transmission, whose costs can be recovered through transmission rates). This flexibility will encourage investment in new or unconventional transmission assets, including electric storage resources intended to serve a transmission function, by providing developers with regulatory certainty that their proposals will be seriously and fairly considered.

In applying the fourth principle, Exelon believes that the Commission should also adopt limited modifications to its existing framework for evaluating incentive applications, expanding it to consider a transmission project's expected benefits in addition to the risks and challenges that it faces (as discussed below in section II.B.2.a). It reflects a more flexible application of the Commission's existing policies because it would provide the Commission with greater discretion

[13] *Commonwealth Edison Company*, 167 FERC ¶ 61,173, at PP 25-27 (2019) (ComEd Superconductor Order).
[14] *See Commonwealth Edison Company Superconductor Cable Project*, Docket No. ER19-1478 (filed Mar. 29, 2019) (ComEd Superconductor Project Filing).
[15] ComEd Superconductor Order, 167 FERC ¶ 61,173 at PP 28-34.

to grant incentives based on the facts and circumstances of specific cases, moving away from the more rigid framework today that focuses primarily on the risks and challenges that a transmission project faces regardless of its benefits. With the added flexibility that considering a wider range of factors when evaluating incentive requests will bring, such a benefits-based approach will support needed and beneficial transmission investments by allowing the Commission to grant incentives based on the project benefits that an applicant has demonstrated, even if that project does not face exceptional risks or challenges.

The Commission should also be flexible in applying its accounting rules to new technologies that utilities adopt to enhance the cybersecurity of their transmission systems (see section II.C.5 below). The technologies available to cost-effectively detect and mitigate cybersecurity threats are continually evolving and do not always resemble conventional transmission plant. To remove barriers to these investments, the Commission should confirm that its accounting rules are flexible enough to allow for capitalization of investments in new technologies needed to enhance cybersecurity when appropriate (e.g., when the investment increases the general utility of a utility's transmission assets).

Finally, the Commission should provide regulatory certainty by formally acknowledging the value of transmission investments that meet reliability and resilience needs that are not addressed under mandatory reliability standards. This can be implemented in the ordinary course through Commission orders or through a separate Policy Statement. While mandatory reliability standards provide a strong foundation for planning a reliable transmission system, individual transmission owners are in the best position to assess their own unique system needs and the needs of their customers. In fact, it is often the responsibility of the transmission owner to fulfill these local reliability needs – regional planners, such as the RTOs/ISOs, do not plan for or require such investments. The need for transmission facilities to meet mandatory reliability standards is indisputable; however, transmission investments that address local reliability needs are equally important. They provide significant value to customers, reducing the risk of losing significant load or experiencing extended outages. By providing certainty that it recognizes their value, the Commission could better support investment in these facilities, reducing the risk that they will be subject to an unsubstantiated prudence challenge.

In sum, Exelon does not believe that the Commission needs to significantly revise its existing framework for evaluating incentive applications. Refining the framework to allow the Commission to consider the benefits that transmission projects provide in addition to the risks and challenges that they face, as proposed in section II.B.2.a below, should increase the Commission's flexibility to grant incentives to needed and beneficial transmission investments. And as discussed in section II.D.2.a below, making the abandoned plant incentive automatic for transmission projects that a utility is directed to build (whether by an RTO/ISO or relevant regulatory authority) will better reflect a utility's control over the decision to undertake these specific transmission investments. With these modifications, the Commission's incentives policy should sufficiently incent new transmission investments that benefit customers, fulfilling the Congressional mandate set forth in FPA section 219. Accordingly, the Commission should refocus its attention and resources on providing regulatory certainty in its ordinary course of business, applying the five key ratemaking principles discussed above.

B. Approach to Incentive Policy

1. Incentives Based on Project Risks and Challenges

In Questions 1 through 3, the Commission asks for comment on its existing framework for evaluating requests for incentives, i.e., granting incentives based on the risks and challenges of the particular transmission project for which they have been requested. As a threshold matter, focusing solely on risks and challenges is inconsistent with the Commission's obligations under FPA section 219, which provides that:

> [T]he 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.[16]

Thus, the Commission has what amounts to a legislative mandate to consider the benefits that a transmission project would provide to consumers. While the statute does not preclude the Commission from considering the risks and challenges that a transmission project faces when evaluating incentive applications, to fulfill its statutory duties, the Commission should modify its existing framework to allow for consideration of the benefits that a project provides (as discussed below in more detail in section II.B.2.a).

As demonstrated in the language of the statute, Congress' intent in enacting FPA section 219 was to provide incentives for transmission projects that benefit consumers. Limiting eligibility for incentives to transmission projects that face significant risks and challenges, regardless of the benefits that they provide, is somewhat inconsistent with the statute. And the statute is not the only factor that argues in favoring of modifying the Commission's framework for evaluating incentive applications to allow for the consideration of a transmission project's benefits in addition to the risk and challenges that it faces. More broadly, utilities invest in transmission infrastructure in order to benefit their customers – a robust, resilient, and secure transmission system supports the reliable delivery of low-cost power to customers and provides

[16] 16 U.S.C. § 824s(a) (2012), emphasis added.

access to new resources. If the Commission's goal in issuing this NOI is to modify its framework for evaluating incentive applications to better incentivize transmission development that benefits customers, the most effective way to do so is to consider the benefits that a transmission project would provide in its analysis. Otherwise, the Commission risks incentivizing utilities to prioritize particularly risky or challenging projects over those that provide the greatest benefit to their customers.

That is not to say, however, that the Commission should completely abandon its consideration of risks and challenges when evaluating incentive applications. The risks and challenges that a particular transmission project faces could pose barriers to its development that incentives could help to alleviate; failing to address those risks and challenges could undermine its development. Therefore, the Commission should continue to allow incentive applicants to demonstrate that their transmission project merits incentives because it faces certain risks and challenges. What Exelon is arguing for here is not a wholesale reworking of the Commission's existing framework for evaluating incentive applications; rather, we believe that the Commission should be more flexible in its implementation, expanding its evaluation to include the benefits that a transmission project provides and moving away from the more rigid risks and challenges framework that the Commission adopted in its 2012 Policy Statement.[17]

Finally, the Commission notes in Question 3 that it 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, inquiring whether it should change its approach.[18] From Exelon's

[17] *Promoting Transmission Investment through Pricing Reform*, 141 FERC ¶ 61,129 (2012) (2012 Policy Statement).
[18] As Exelon explains in our ROE Policy NOI Comments, with certain clarifications and modifications, the proposed framework for evaluating ROE that the Commission set forth in the *Coakley* and MISO Briefing Orders will provide

perspective, the risks that the Commission considers when setting base ROE are different than the risks that a particular transmission project may face. Specifically, when setting a utility's base ROE, the Commission considers the risks that affect the utility's business as a whole. In contrast, the risks that incentive applicants tend to highlight are risks that are specific to a particular transmission project – such as siting issues, significant regulatory challenges, etc. These risks might, if a transmission project is a large enough percentage of a utility's capital spend, affect the utility's overall business risk, but typically, these risks are not so significant and instead are more relevant to whether a utility will move forward with a specific project. In any case, the risks associated with a new transmission project are not necessarily reflected in a utility's existing base ROE, which may have been established before the utility contemplated the project for which it is requesting incentives.

2. Incentives Based on Expected Project Benefits

a. The Role of Benefits in the Commission's Evaluation of Incentive Applications

In Question 4 through 11, the Commission poses a number of questions concerning the role that benefits should play in its evaluation of incentive applications. As described above in section II.B.1, Exelon respectfully submits that under the statute, the Commission should consider benefits in its evaluation of incentive applications.[19] The statute focuses on

---

the regulatory certainty needed to support new transmission investment. *Martha Coakley v. Bangor Hydro-Elec. Co.*, 165 FERC ¶ 61,030 (2018) (*Coakley* Briefing Order); *Ass'n of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,118 (2018) (MISO Briefing Order). It will ensure that utilities have the opportunity to earn a fair and predictable return on their investments, facilitating transmission investment and reducing the likelihood of prolonged litigation. Thus, the Commission should expeditiously close the ROE Policy NOI proceeding and adopt the proposed ROE framework set forth in the *Coakley* and MISO Briefing Orders and refine that framework consistent with the clarifications and modifications that Exelon recommends in its comments. *See* ROE Policy NOI Comments.

[19] Specifically, FPA section 219 states that the Commission must establish incentive rate treatments to:

incentivizing transmission development that benefits customers, whether by maintaining or enhancing reliability or by reducing transmission congestion or expanding transmission capacity to allow for the delivery of lower-cost power. Accordingly, the Commission should refine its framework for evaluating incentive applications to consider the benefits that the applicant's transmission project would provide (while continuing to allow incentive applicants to demonstrate that their transmission project merits incentives because it faces certain risks and challenges, as discussed in section II.B.1 above).

To a degree, the Commission already considers the benefits that a transmission project provides when evaluating incentive applications under the existing framework. In implementing FPA section 219 in Order No. 679,[20] the Commission found that for its transmission project to be eligible for incentive rate treatments, an applicant must demonstrate that its project ensures reliability or reduces the cost of delivered power by reducing transmission congestion (the two primary benefits to which FPA section 219 refers). However, once an applicant met that threshold, under Order No. 679, the Commission's analysis then shifted to the "nexus" between the incentive being sought and the investment being made, through which the Commission determined the appropriate combination and level of incentives on a case-by-case basis.[21] The

> (1) promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all [transmission facilities]…; (2) provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); [and] (3) encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of the existing transmission facilities and improve the operations of the facilities…

16 U.S.C. § 824s(b).

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

[21] In applying the nexus test, the Commission clearly contemplated the importance of factors besides benefits, stating that the "most compelling" candidates for incentives are "new projects that present special risks or

Commission's 2012 Policy Statement moved further away from an analytical framework that emphasizes benefits, reframing its analysis of ROE incentive adder requests to more specifically focus on the risks and challenges of the transmission project at issue. In adopting this approach, the Commission has drifted away from the language and intent of the statute, which focuses on benefits; to more faithfully implement Congress' directives, the Commission should refine its framework for evaluating incentive applications to consider the benefits that a transmission project provides in addition to the risks and challenges that it faces.

Exelon is not arguing, however, that all transmission facilities that offer benefits to customers necessarily merit any form of transmission rate making treatment. As explained in section II.A above, the Commission need not adopt new incentives for specific types of transmission projects, which would do little to support beneficial and needed transmission investment. In fact, the Commission can best support beneficial transmission development through timely and fair action on routine filings that establish or modify rates or rate structures. Moreover, without adopting any completely new policies, the Commission could support beneficial transmission development by flexibly applying its existing policies. Timely, fair, and flexible implementation of the Commission's current policies is sufficient to support the development of the majority of needed transmission facilities.

And flexibility is exactly what Exelon requests here – rather than rigidly applying its policies as set forth in Order No. 679 and the 2012 Policy Statement, the Commission should place greater emphasis on the benefits that a transmission project will provide when evaluating

---

challenges, not routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service." Order No. 679, 116 FERC ¶ 61,057 at PP 23, 60.

incentive applications. For example, even if a transmission project is not particularly risky or challenging, the Commission should still be open to providing incentives (whether risk-reducing incentives or an ROE incentive adder) if the project offers sufficient benefits to customers. Exelon believes that Commission discretion is appropriate in determining what "sufficient" means in each case; the Commission should evaluate, based on the specific facts and circumstances set forth in the record, whether a transmission project merits incentive rate treatment given the benefits that the applicant has demonstrated that it will provide. Not every beneficial transmission project will necessarily merit incentives under this framework, but the Commission will be able to consider the totality of the record (i.e., not only the risks and challenges that a project faces, but also the benefits that it will provide) when ruling on incentive applications. ComEd's Superconductor Project is exactly the type of beneficial transmission investment that the refined framework would support – while the Commission found that the ComEd Superconductor Project merited the abandoned plant incentive based solely on the risks and challenges that it faced,[22] the project also will provide significant reliability and resilience benefits to ComEd's customers that could have similarly justified the risk-reducing abandoned plant incentive.

In addition, such flexibility will best support the development and deployment of new and innovative advanced transmission technologies. The electric industry is rapidly changing, and along with it the needs that transmission infrastructure must fulfill and the transmission technologies available to meet those needs. For example, new transmission facilities are

[22] ComEd Superconductor Order, 167 FERC ¶ 61,173 at PP 28-34.

increasingly playing a role in addressing recent generator retirements,[23] supporting the integration of renewable generation resources,[24] and facilitating emissions reductions.[25] Moreover, deployment of advanced transmission technologies, such as Phasor Measurement Units, supports greater operational awareness, enhancing the reliability and resilience of the electric grid.[26] Allowing an applicant to demonstrate in its incentive application the benefits that its transmission project will provide, without any limitation, will provide the Commission with the flexibility that it needs to react to changes in the electric industry; imposing rigid definitions of benefits or criteria will only undermine the adoption of the new approaches to transmission development needed to modernize the grid.

In sum, while Exelon does not believe that the Commission should entirely upend its existing framework for evaluating incentive applications, Exelon supports refining that framework to include consideration of the benefits that a particular transmission project provides. In general, the Commission's performance of its statutory duties in the ordinary course of business is the most significant driver of beneficial transmission investments. Incentives may help to support such investments in certain circumstances, but diverting Commission resources and time away from its day-to-day operations to work on crafting new incentives policies may only undermine beneficial transmission development more broadly (most of which is routine in nature). Considering the benefits of a transmission project in addition to risks and challenges where an applicant believes that those benefits justify its incentive request will address the weaknesses of the Commission's current framework for evaluating incentive applications

---

[23] PJM Transmission System Benefits Report at 26.
[24] *Id.* at 30-33.
[25] *Id.* at 33-34.
[26] *Id.* at 59-60.

without necessitating wholesale revisions to its existing policies, best balancing the Commission's statutory obligation under FPA section 219 to provide incentive rate treatments with the need for timely and fair consideration of routine ratemaking matters.

b. Bright-line Criteria and Benefit-to-Cost Ratios

The recommendation for flexibility carries over to the mechanism through which the Commission should consider benefits when evaluating incentive applications. In several of its questions, the Commission suggests bright-line criteria and benefit-to-cost ratios as mechanisms for assessing whether the benefits that a transmission project provides are sufficient for it to merit incentives. Exelon counsels against the adoption of such a rigid framework for several reasons. First, establishing bright-line criteria with respect to the amount of benefits that a transmission project must provide or the benefit-to-cost ratio that it must meet to be eligible for incentives would require the quantification of benefits in all cases. While many types of benefits are susceptible to quantification (e.g., production cost savings and reduced costs to load), others are not. For example, the benefits of increased transmission system flexibility could be difficult to quantify given the optionality that it provides for system operators under a wide range of operating conditions.

Thus, to allow parties flexibility in demonstrating benefits, Exelon urges the Commission to refrain from adopting bright-line criteria or benefit-to-cost ratios for use in evaluating incentive applications. In addition, adopting bright-line criteria or a benefit-to-cost ratio could render transmission projects that provide benefits set forth in FPA section 219 (i.e., ensure reliability or reduce congestion) ineligible for incentives. While there may be reasons that such a project may not merit incentives, categorically precluding the project from receiving incentives through the adoption of bright-line criteria or a benefit-to-cost ratio is unreasonable and inconsistent with the statute. Again, a flexible framework for evaluating incentive applications would allow the Commission to consider the specific facts and circumstances set before it in the record, such that the Commission's decision on whether a transmission project merits incentives would reflect the totality of evidence rather than the results of a single test (i.e., whether the transmission project satisfies the bright-line criteria or benefit-to-cost ratio).

The Commission also asks whether it should condition incentives on the benefits set forth in the incentive application being realized.[27] It should not. Revoking incentives that the Commission has already granted if a transmission project does not provide the expected benefits (or does so at increased cost) or conditioning incentives on the realization of benefits would create regulatory uncertainty that would undermine the efficacy of the incentives. While Exelon recognizes the need to ensure that only those transmission projects that provide significant benefits receive incentives, an applicant should not be punished if its good faith estimates of benefits do not come to fruition given the difficulties in accurately estimating benefits, changes in project use from the use anticipated when the project was developed, or other changed circumstances. In some cases, the benefits of a transmission project identified when it was planned will not be realized, at no fault of the transmission developer. For example, the economic benefits of a transmission project will vary based on the prices of the fuels used in power production, changes in the generation resource mix, and changes in demand, among other factors. Regardless of its best efforts to be accurate, it is impossible for a developer to perfectly predict a project's benefits in the face of such potential future changes. Revoking or conditioning incentives based on the realization of benefits will not produce more accurate

[27] Our response here applies to Question 88 as well.

estimates of benefits, but instead will result in applicants either underestimating the benefits of their projects to reduce the likelihood of their incentives being revoked or simply forgoing incentives, and potentially the proposed project, in the first place.

c. General Principles for Evaluating Potential Benefits

In Question 5, the Commission asks whether it should lay out general principles for evaluating the potential benefits of a proposed transmission project. While Exelon does not oppose the adoption of general principles (consistent with the principles set forth in FPA section 219) to evaluate whether a transmission project is eligible for incentives, this approach largely reflects the Commission's policy today. Under the Commission's existing framework for evaluating incentive applications, an applicant must demonstrate that its project satisfies one of two principles to be eligible for incentives: the project must ensure reliability or reduce the cost of delivered power by reducing transmission congestion. Consistent with our suggestion that the Commission refine its analysis of incentive applications to include consideration of the benefits of transmission projects, the Commission could expand the principles that it will apply to determine whether a transmission project merits incentives to better reflect the benefits that transmission infrastructure provides to customers. For example, it could find that a transmission project may merit incentives if it (1) promotes reliability (such as by reducing the frequency or duration of outages), (2) supports economically efficient transmission and generation of electricity, (3) increases the capacity and efficiency of existing transmission facilities, (4) improves operations of existing facilities, or (5) enhances resilience and security. Applicants could then demonstrate in their incentive applications how their transmission projects provide sufficient benefits to merit incentives, similar to their demonstration of risks and challenges today.

However, the Commission should not limit the benefits that an applicant may demonstrate in its incentive application to those reflected in any set of principles it adopts. The Commission needs to retain flexibility to consider a wide range of benefits when evaluating incentive applications; limiting itself to consideration of a discrete list will hinder its ability to promote beneficial transmission investment that will support the grid of the future. As the electric industry evolves, so too may the benefits of transmission facilities. For example, enhanced resilience and security are not explicitly captured in FPA section 219. Nonetheless, they are important benefits that transmission infrastructure provides that the Commission should consider when evaluating incentive applications. Thus, while the Commission could adopt general principles to help provide guidance to the industry on transmission projects that may merit incentives, those principles should not limit the Commission's consideration of other benefits. Otherwise, the general principles could preclude new technologies that provide new types of benefits from being eligible for incentives, despite the benefits that they provide.

3. Incentives Based on Project Characteristics

In Questions 12 through 16, the Commission asks whether it should grant incentives based on a transmission project's characteristics. Exelon opposes such an approach. The Commission not should modify its framework for evaluating incentive applications to grant incentives (automatically or otherwise) to a transmission project based on its characteristics (e.g., interregional, high-voltage, or long-distance). Again, adopting such an approach would divorce the Commission's incentives policy from the intent of FPA section 219, which explicitly focuses on the benefits that transmission infrastructure provides to customers through promotion of "reliable and economically efficient transmission and generation of electricity."[28] While using project characteristics as a proxy for the benefits that a transmission project will provide may in some instances accurately capture the project's benefits, in other cases, it could preclude transmission projects with significant benefits from being eligible for incentive rate treatment.

The potential mismatch between a transmission project's benefits and its characteristics may be particularly apparent where a transmission developer seeks to use an advanced transmission technology. As discussed above in section II.A, the ComEd Superconductor Project is an example of a project that, because it deploys an advanced technology (high temperature superconducting cable), can provide the same reliability, resilience, and power transfer benefits as conventional high-voltage transmission facilities at a much lower voltage (12 kV).[29] Imposing a rigid standard for granting incentives that reflects a transmission project's characteristics, such as its voltage level, could disincentivize the adoption of such advanced technologies by precluding them from being eligible for incentives.

And relying on project characteristics to evaluate incentive applications could drive applicants to design their transmission projects to reflect the characteristics that the Commission has chosen to incentivize rather than to maximize those projects' cost-effectiveness and benefits to customers. The transmission investments that provide the most value to our customers are not necessarily projects that are high-voltage or long-distance; they are often the day-to-day investments that help us to provide more reliable and secure service. As discussed in section II.A above, devoting time and resources to completely reworking the Commission's incentives

---

[28] 16 U.S.C. § 824s(b)(1) (2012).
[29] ComEd Superconductor Order, 167 FERC ¶ 61,173 at P 27.

policies to support specific types of transmission projects with certain characteristics, or creating new incentives for such projects, may unintentionally distract from what is truly needed to support these day-to-day transmission investments: rates and rate structures that allow for timely cost recovery for, and a reasonable rate of return on, those investments. Instead of asking how to encourage particular types of transmission projects through specific incentives, the Commission's time would be better spent evaluating whether it is supporting beneficial transmission investments in the ordinary course of its performance of its statutory duties.

While providing incentives based on a transmission project's characteristics could increase regulatory certainty—which we generally support—under these circumstances, regulatory certainty would come at a significant cost: the increased probability that the Commission will deny incentives for transmission projects that provide significant benefits, yet grant incentives to transmission projects that are less beneficial but have certain project characteristics. This outcome is not sensible, nor will it support beneficial and needed transmission investment. While using project characteristics as a proxy for benefits may be appropriate in some cases, Exelon believes that for purposes of evaluating incentive applications for specific transmission projects, the Commission should consider the applicant's demonstration of project benefits rather than use the project's characteristics as a proxy for those benefits. The applicant will then have the opportunity to explain how its transmission project may have benefits that go beyond those that a project with similar characteristics typically provides, as well as the other relevant facts and circumstances surrounding its project that may support its incentive request.

C. Incentive Objectives

In Questions 17 through 49, the Commission poses questions about a wide range of benefits and project characteristics, inquiring as to whether it should offer incentives tailored to transmission projects that provide the specified benefits or have the specified characteristics. As an initial matter, the Commission is already required under FPA section 219 to establish incentive rate treatments "for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion,"[30] as well as to "encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of the existing transmission facilities and improve [their] operations."[31] At a bare minimum, then, the Commission should consider whether a transmission facility improves reliability, reduces congestion, increases the capacity and efficiency of existing transmission facilities, or improves the operations of such facilities when evaluating incentive applications. But the Commission is not required (and should not) tailor specific incentives, such as an ROE adder equal to a set amount of basis points, for transmission facilities with these characteristics. Instead, as Exelon explains in section II.B.2.a above, the Commission should modify its existing framework for evaluating incentive applications (including those that request ROE adders) to consider a transmission project's benefits in addition to the risks and challenges that it faces on a case-by-case basis.

In addition, Exelon does not oppose expanding the types of benefits that the Commission considers when evaluating incentive applications beyond the discrete benefits set forth in FPA section 219. In fact, certain types of benefits listed below, such as security and resilience, are significant benefits that transmission facilities provide to customers that, while not explicitly

[30] 16 U.S.C. § 824s(a).
[31] 16 U.S.C. § 824s(b).

listed in FPA section 219, are increasingly important as the nation's transmission system (and the threats to it) evolve. However, as discussed in section II.B.2.a above, the most effective way to incent beneficial transmission development is not to provide incentives to transmission projects based on specific characteristics; rather, it is to consider the full range of benefits that a transmission project provides in addition to the risks and challenges that it faces when evaluating individual incentive applications. Adopting such an approach (without any limitations as to the project benefits that an applicant may demonstrate) will help to support transmission investment, without being so restrictive as to exclude beneficial transmission projects from eligibility for incentives (as granting incentives based solely on a transmission project's inclusion in one of the specific categories listed in the NOI could do). Again, the Commission should refine its evaluation of incentive applications to consider the benefits that a transmission project provides in addition to the risks and challenges that it faces, not simply whether it fits neatly into a particular category of project that may or may not meet the unique needs of a particular utility's customers or of a particular region.

Below, Exelon provides more specific thoughts on a few of the types of transmission projects and benefits that the Commission describes.

1. Reliability Benefits

In Questions 17 through 21, the Commission asks several questions about how it should tailor incentives to promote reliability projects. Exelon agrees that improved reliability is one of the most important benefits that new transmission infrastructure development can provide, and clearly the Commission recognizes it as such.[32] Specific incentives for transmission projects that enhance reliability are unnecessary, however, to incent utilities to invest in such project – what is important is that the Commission recognize the value of these investments. As Exelon explained in its comments following the March 2019 Technical Conference,[33] utilities must comply with North American Electric Reliability Corporation (NERC), regional, and state-level reliability standards when planning their transmission standards. These standards serve as a foundation to ensuring a reliable transmission system – they set forth the minimum requirements that each utility's transmission system must meet in terms of reliability. But they do not address all of a utility's reliability needs. Utilities often identify and invest in additional transmission facilities to support reliable service to their customers, transmission investments needed to address vulnerabilities that, while not severe enough to violate NERC or other reliability standards, could nonetheless significantly disrupt service. Moreover, utilities rely on strict internal design and engineering standards for their transmission systems to ensure that these systems remain reliable and resilient for decades to come. They also rely on the experience and expertise of their engineers and other employees in assessing their needs.

Exelon believes that investments in response to these considerations are essential to providing our customers with reliable and cost-effective electric service, reducing the frequency and duration of outages and contributing to a more robust transmission system, which not only reduces the system's vulnerabilities to threats and disruptive events today, but also helps utilities to better prepare for the threats of tomorrow. To incent the development of these transmission

[32] *See Security Investments for Energy Infrastructure Technical Conference*, Supplemental Notice of Technical Conference, Docket No. AD19-12 (Mar. 21, 2019) (March 2019 Technical Conference); *see also Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (2018).
[33] *See* Exelon Physical and Cyber Security Post-Technical Conference Comments at 12-13.

facilities that enhance reliability (but are not addressed by or go above and beyond mandatory reliability standards), the Commission should acknowledge the value that such investments can provide to customers. This can be implemented in the ordinary course through Commission orders or through a separate Policy Statement. To be clear, Exelon is not asking for any sort of finding that such investments are necessarily prudent; of course, the Commission will continue to make prudence determinations given the facts and circumstances of specific cases before it. Rather, Exelon seeks regulatory certainty that the Commission recognizes that investments to address reliability needs beyond merely satisfying mandatory reliability standards can provide significant value to our customers.

With this regulatory certainty, the Commission's existing framework for evaluating incentive applications (modified to include the consideration of benefits as Exelon recommends in section II.B.2.a above) is sufficient to incent investment in transmission facilities that enhance reliability, including those that expand access to essential reliability services. Such consideration of reliability benefits is consistent with the statute's directive that the Commission establish incentive rate treatments "for the purpose of benefiting consumers by ensuring reliability."[34] Additional new incentives for reliability projects are unnecessary, and devoting the Commission's limited time and resources to considering and developing such special new incentives for reliability projects is not necessary to further incent their development. Instead, the Commission should focus its efforts on timely and fairly acting on the incentive applications for such projects that come before it.

[34] 16 U.S.C. § 824s(a) (2012).

2. Economic Efficiency Benefits

In Questions 22 through 25, the Commission asks whether it should tailor incentives for transmission projects that reduce congestion or facilitate access to additional generation, including whether it should establish bright-line criteria. Again, Exelon believes that additional new incentives tailored to such projects are unnecessary and will only distract from the Commission's timely performance of its day-to-day regulatory responsibilities. That said, Exelon agrees that, consistent with FPA section 219, the Commission should incent transmission facilities that benefit consumers by reducing transmission congestion and, in turn, the cost of delivered power.[35] Considering such benefits (including those associated with facilitating access to additional generation) as part of the benefits-based approach for which Exelon advocates in section II.B.2.a above is sufficient to achieve this objective without special, more tailored incentives. For transmission projects needed to facilitate access to additional generation, the Commission should also continue to respect state policies that drive transmission investment. Specifically, the Commission should ensure that there is a means for utilities to plan and recover the costs of transmission needed to support state policy objectives, whether those objectives are to facilitate the development of wind generation, solar generation, electric storage resources, distributed energy resources, or some other technology.

With respect to the use of bright-line criteria, Exelon discusses its hesitancy with such an approach in section II.B.2.b above. Those arguments apply here as well. In addition, it would be inappropriate for the Commission to mandate the range of benefits that an applicant can or cannot use to demonstrate that its transmission project merits incentives, as Question 24

[35] 16 U.S.C. § 824s(a).

suggests. Different utilities and regions may consider different sets of benefits when evaluating the need for new transmission facilities and may weigh different types of benefits differently depending on their specific circumstances. Adopting a standard set of benefits that would apply nationwide could disincentivize investments in transmission projects that particular utilities or regions, on behalf of their customers, find beneficial. Instead, the Commission should consider the benefits of each transmission project on a case-by-case basis when evaluating incentive applications, allowing each utility the flexibility to demonstrate in its application the particular benefits of its project that justify incentives.

3. Persistent Geographic Needs

In Questions 26 through 28, the Commission asks whether it should provide tailored incentives to transmission projects based on the geographic area in which they are located. Exelon opposes such an approach. Instead, the Commission should adopt the approach described in section II.B.2.a, under which the Commission would flexibly consider all of the benefits that a transmission project provides in addition to the risks and challenges that it faces when evaluating incentive applications, including those benefits associated with addressing persistent geographic needs. Tailoring an incentive to transmission projects located in certain geographic areas would divorce a transmission project's eligibility for incentives from the benefits it provides, inconsistent with the statute (see section II.B.3 above). For example, a transmission project located in a pre-defined geographic area might meet persistent needs within that area (e.g., reduce congestion), but its location in the area alone does not guarantee such a result.

4. Flexible Transmission System Operation

In Questions 29-31, the Commission inquires whether it should incent flexibility and, if so, how. Flexibility means a robust transmission system with redundancies built in, such that the system can quickly respond to and recover from contingencies (e.g., load can be fed from multiple lines should a single line go out of service). Exelon already considers the need for flexibility when planning its transmission system[36] – no additional new incentives are necessary (beyond considering this issue as it comes up in routine filings). To best support investments in flexibility (which are, at core, intended to enhance reliability), the Commission should adopt Exelon's recommendation in sections II.A and II.C.1 above by acknowledging that transmission investments to address reliability needs beyond those addressed in mandatory reliability standards can provide significant value to customers. Such acknowledgement would encourage utilities to include flexibility in their internal planning criteria where they have not already done so and will support those utilities that already have, driving new transmission investments. In addition, when evaluating incentive applications under the approach proposed above (see section II.B.2.a), the Commission should consider any flexibility benefits that a transmission project provides and should timely and fairly act on the incentive application.

5. Security

In Questions 32 and 33, the Commission asks whether it should incent physical and cyber security investments. As Exelon explained in its comments in response to the Commission's March 28, 2019 joint technical conference with the Department of Energy,[37] Exelon is

---

[36] ComEd Superconductor Project is an example of a transmission facility that was planned in part to enhance system flexibility – it will convert two radial feeders into a looped network, providing for bidirectional flows. *See* ComEd Superconductor Project Filing.
[37] *See* Exelon Physical and Cyber Security Post-Technical Conference Comments.

committed to ensuring that our energy infrastructure assets are secure; we have made, and will continue to make, the physical and cyber security investments necessary to protect our electricity delivery and supply systems from threats we are made aware of. No additional new incentives are needed to support these investments and, in fact, an initiative to revise existing incentives or develop new ones may unintentionally distract resources from what is truly needed to continue making investments in the physical and cyber security of our assets: the regulatory certainty provided by timely and fair Commission action on filings that involve cost recovery and price formation matters.

That said, Exelon's proposed approach to evaluating incentive applications (described in section II.B.2.a above) is flexible enough for the Commission to consider the benefits associated with investments that enhance physical and cyber security where warranted. And as discussed above in section II.A, flexibility in the Commission's implementation of its existing accounting rules could help to remove barriers to investments in new technologies that can enhance cybersecurity. To that end, the Commission should confirm that its accounting rules are flexible enough to allow for capitalization of the costs associated with these new technologies as appropriate. Finally, as discussed above in sections II.A and II.C.1 and in our comments in response to the March 28, 2019 technical conference,[38] the Commission should acknowledge that transmission investments to address reliability needs beyond those addressed in mandatory reliability standards (such as certain physical and cyber security investments) can have significant value to customers.

[38] *See* Exelon Physical and Cyber Security Post-Technical Conference Comments at 12-13.

6. Resilience

In Questions 34 through 36, the Commission poses several questions about incentives for transmission projects that enhance resilience. There is a wide range of transmission projects that can provide resilience benefits, such as new transmission lines to build redundancies into the existing transmission system, infrastructure hardening against severe weather events and other natural disasters, and measures to enhance system awareness. Such projects reduce the frequency and duration of outages and allow system operators to respond more effectively to contingencies, and the Commission has recognized the value that they can provide.[39] Consistent with the approach that Exelon proposes in section II.B.2.a above, the Commission should consider these benefits when evaluating incentive applications. By timely and fairly considering such applications, like ComEd's request for the abandoned plant incentive for its Superconductor Project,[40] the Commission can support utilities in their efforts to enhance the resilience of their transmission systems. Moreover, as discussed in sections II.A and II.C.1 above, the Commission should acknowledge that transmission investments to address reliability needs beyond those addressed in mandatory reliability standards can have significant value to customers.

7. Improving Existing Transmission Facilities

In Questions 37 through 43, the Commission asks several questions about how it should incentivize the deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission grid. As an initial matter, utilities are already

[39] *See, e.g.*, *Grid Reliability and Resilience Pricing*, 162 FERC ¶ 61,012 (2018); *Security Investments for Energy Infrastructure Technical Conference*, Transcript, Docket No. AD19-12 (Mar. 21, 2019).
[40] *See* ComEd Superconductor Order, 167 FERC ¶ 61,173. As noted above, the Superconductor Project will enhance the reliability and resilience of ComEd's system in downtown Chicago by deploying an advanced transmission technology.

adopting these technologies and measures where cost-effective. For example, many RTOs/ISOs already use dynamic line ratings to the extent feasible.[41] The deployment of technologies and other measures to enhance the capacity, efficiency, and operation of the transmission grid can provide significant benefits to customers, as recognized in FPA section 219(b)(3). For example, advancements in materials science can improve the carrying capacity of transmission lines, allowing for more efficient use of existing infrastructure and rights of way, minimizing the requirements for new infrastructure and rights of way. Thus, the Commission should consider whether a transmission project would enhance the capacity, efficiency, and operation of the transmission grid under the approach to evaluating incentive applications that Exelon proposes in section II.B.2.a above. Such consideration would reflect the benefits that more efficiently using the existing transmission system (as well as designing new transmission facilities for maximum efficiency) can bring, not only in terms of improved reliability and decreased transmission congestion, but also in reducing the footprint of the transmission facilities needed to provide reliable service.

Finally, the Commission could better incentivize utilities to improve the efficiency of individual transmission assets by allowing utilities to capitalize costs related to vegetation management that they must now expense. Vegetation management is essential to avoiding potentially significant outage issues[42] and enhancing the capacity and optimizing the operations

[41] But it is important to note that some of these technologies and measures, such as dynamic line ratings, do not necessarily add capacity to the grid during peak periods (when the temperature is likely to be highest and thus the rating of a transmission line lowest), which limits the ability of these technologies and measures to meet transmission needs driven by mandatory reliability standards.

[42] For example, the August 2003 Northeast Blackout was caused in part by poor vegetation management. *See Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations,* U.S.-Canada Power System Outage Task Force (Apr. 2004), https://www.nerc.com/pa/rrm/ea/2003%20Blackout%20Final%20Report/ch1-3.pdf.

of transmission facilities; it can alleviate concerns about insufficient clearance due to sag that may limit a line's capacity and operation. The NERC reliability standards, however, only set forth minimum requirements for utilities' vegetation management practices as they relate to transmission facilities that operate at or above 100 kV. As a result, the NERC reliability standards do not provide an incentive for robust vegetation management practices for transmission facilities that operate below 100 kV. Nor do they incentivize utilities to consider whether more rigorous vegetation management programs for transmission facilities that operate at or above 100 kV could benefit their customers through increased reliability and more efficient operation. Therefore, the Commission should consider allowing utilities to propose to capitalize, rather than expense, vegetation management programs that go above and beyond the NERC reliability standards to provide these benefits as a means of encouraging such investment.

8. Interregional Transmission Projects

In Questions 44 through 46, the Commission poses questions on incentives specifically for interregional transmission projects. For the reasons set forth in section II.B.3 above, Exelon opposes incentives tailored specifically for interregional transmission projects. While some interregional transmission projects may offer significant benefits to customers (and thus potentially merit incentives), the simple fact that a transmission project spans more than one transmission planning region is insufficient to definitively demonstrate that the project will offer significant benefits. Instead, the Commission should adopt the approach to evaluating incentive applications proposed above (see section II.B.2.a), allowing the applicant to demonstrate any benefits that an interregional transmission project provides in its application.

D. Existing Incentives

1. ROE-Adder Incentives

a. RTO/ISO Participation

In Questions 61 through 66, the Commission poses a number of questions about the RTO Participation Adder. RTO/ISO participation has a wide range of well-documented benefits for a utility's customers. However, RTO participation is not beneficial for the utility in all respects – transmission-owning RTO/ISO members face significant risks as a result of their membership that utilities outside of RTOs/ISOs do not experience, as described further below. The RTO Participation Adder, then, serve two purposes: (1) it reflects the benefits that RTO/ISO membership provides to customers (benefits that do not always accrue to the utility) and (2) it compensates utilities for the added risks that they assume when joining an RTO/ISO. While it is reasonable for the Commission to reexamine its policies with the passage of time, none of the changes in the electric industry since the Commission established the RTO Participation Adder in Order No. 679 justify eliminating this incentive – the benefits to customers and risks to utilities remain just as relevant today as they did then. Therefore, the Commission should retain the 50 basis point RTO Participation Adder without modification.

As an initial matter, Congress directed the Commission to provide some form of incentives for RTO/ISO participation and this is regardless of whether that participation is the result of a decision on the part of the utility's management or a regulatory process. Specifically, the statute states that "the Commission *shall*, to the extent within its jurisdiction, provide for incentives to each transmitting utility or electric utility that joins a [RTO/ISO]."[43] While

[43] 16 U.S.C. § 824s(c) (2012), emphasis added.

Congress was not prescriptive as to the form those incentives should take, the existing RTO Participation Adder (i.e., a 50 basis point adder to a transmission-owning RTO/ISO member's base ROE) is reasonable. It not only fulfills the statutory mandate, but also appropriately reflects the benefits that RTO/ISO membership provides to customers and the additional risks that utilities assume when they join.

In addition, FPA section 201 states that:

> For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy…[44]

Eliminating the RTO Participation Adder would undermine such voluntary interconnection. For these reasons, the FPA supports the retention of the RTO Participation Adder.

Regardless, the RTO Participation Adder is justified by the significant benefits that RTO/ISO membership provides directly to a utility's customers, benefits in which the utility does not necessarily share. Those benefits include access to broader markets (and in turn, lower cost delivered power), optimization of the transmission system, regional transmission planning that supports cost-effective transmission development to meet regional needs, reduction of the costs of carrying reserves through reserve sharing, increased resilience through expanded resource diversity,[45] and regional transmission pricing. For example, PJM alone has found that its regional grid and market operations produce annual savings of $2.8 billion to $3.1 billion

---

[44] 16 U.S.C. § 824a(a).

[45] Broad integration of the grid, as is done in RTOs, is one of the best ways to enhance reliability and resilience. The Incentives NOI suggests that the Commission is considering expanding incentives to encourage transmission investments; eliminating or modifying the RTO Participation Adder would have the exact opposite effect.

through enhanced reliability, reduced energy production costs, integration of more efficient resources, generation investment savings, and the provision of grid services.[46]

The Commission has long recognized the importance of these benefits to customers,[47] and many of these benefits are the result of operating the transmission systems of each individual transmission-owning member as a single network.[48] Thus, it is appropriate to apply the RTO Participation Adder to a utility's entire transmission rate base rather than to specific transmission projects. And the benefits that RTO/ISO participation provides are not limited in duration – as long as a utility is an RTO/ISO member, these benefits will continue to accrue to their customers. In fact, limiting the duration of the RTO Participation Adder could reduce a utility's incentive to remain in an RTO/ISO to the continued benefit of its customers[49] (particularly given the risks that RTO/ISO participation entails, as discussed directly below). The Commission should therefore continue to apply the RTO Participation Adder to a utility's entire transmission rate base as long as it remains an RTO/ISO member.

---

[46] *PJM Value Proposition*, PJM Interconnection, L.L.C., https://www.pjm.com/about-pjm/value-proposition.aspx (last visited Jun. 26, 2019).

[47] *See, e.g.*, Order No. 679-A, 117 FERC ¶ 61,345 at P 86 (finding that the consumer benefits, including reliability and cost benefits, are well-documented); *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 31,024 (1999) (finding that RTOs/ISOs will provide benefits that include increased efficiency through regional transmission pricing and the elimination of rate pancaking, improved congestion management, more accurate estimates of Available Transfer Capability, more effective management of loop flows, more efficient planning for transmission and generation investments, increased coordination among state regulatory agencies, reduced transaction costs, facilitation of state retail access programs, facilitation of environmentally preferred generation, improved grid reliability, and fewer opportunities for discriminatory transmission practices).

[48] For example, PJM states in a recent report that, among other benefits, its regional transmission system ensures reliability at the lowest cost, provides access to lower-priced power, enables economic growth, supports operational flexibility, provides access to support in emergency conditions, enhances resilience, and allows for the reliable integration of new resources and retirement of older resources. PJM Transmission System Benefits Report at 3-6.

[49] *See* Order No. 679-A, 117 FERC ¶ 61,345 at P 86 (finding that the best way to ensure that the consumer benefits of RTO/ISO participation are spread as broadly as possible is to "provide an incentive that is widely available to member utilities of Transmission Organizations and is effective for the duration of a utility's membership in the Transmission Organization.").

While RTO/ISO participation provides substantial benefits for customers, it also introduces new risks for transmission-owning members. Thus, the RTO Participation Adder is also necessary to compensate transmission-owning RTO/ISO members for the risks that they assume when joining an RTO/ISO, risks that utilities that remain outside of an RTO/ISO do not face. For example, in joining an RTO/ISO, utilities must relinquish operational control of their transmission facilities. They must abide by market rules and other tariff provisions over which they lack control, provisions that are often the result of broad stakeholder processes in which utilities have limited power.[50] Further, changing certain aspects of their Open Access Transmission Tariffs can be very challenging, if not impossible, given the need to obtain sufficient agreement among the other transmission owners in the RTO/ISO before filing certain tariff revisions under FPA section 205.

In addition, transmission-owning RTO/ISO members agree to rely on the RTO/ISO to plan to meet regional transmission needs, but nonetheless have the obligation to build transmission facilities when directed by the RTO/ISO. As a result, they have less control over their capital spend – they may have to prioritize investments based on the transmission facilities the RTO/ISO directs them to build that they would not otherwise have pursued. And the RTO/ISO ultimately decides whether these transmission projects will move forward; RTO/ISO decisions to cancel projects may leave the utility with stranded costs associated with the abandoned plant, as well as costs incurred in attempts to recover those costs.[51] The foundational

[50] And these market rules can pose risks for transmission-owning RTO/ISO members, for instance, when a market participant defaults. *See e.g.*, *PJM to Examine FTR Auction After FERC Order*, PJM Inside Lines (Feb. 7, 2019), *available at* https://insidelines.pjm.com/pjm-to-examine-ftr-auction-after-ferc-order/ (estimating the impact of the June 2018 GreenHat default on the PJM membership).

[51] *See, e.g.*, *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,156 (2013) (finding that the PHI Companies were eligible to recover their prudently-incurred costs for the abandoned Mid-Atlantic Power Pathway Project when PJM

agreements that set forth the terms and conditions of their participation in the RTO/ISO can change at the direction of the Commission, changing the bargain that the utilities struck when joining. The regional cost allocation associated with RTO/ISO membership has risks as well; it may be difficult for transmission-owning RTO/ISO members to demonstrate to their customers the benefits associated with regional transmission facilities for which they are allocated costs, especially when those facilities are located far from the transmission owner's zone. And should the utility choose (or be directed by a relevant regulatory authority) to leave the RTO/ISO if its participation no longer provides sufficient benefits to its customers, it may face significant costs. The existing 50 basis point RTO Participation Adder is reasonable compensation for these risks.

Importantly, the benefits that RTO/ISO participation provides to customers (and the risks that it entails to transmission-owning utilities) are in no way dependent on whether that participation is voluntary. Moreover, the statute does not impose any limitation on incentives for RTO/ISO participation based on whether a utility voluntarily joined. Instead, FPA section 219 directs the Commission to "provide for incentives to *each transmitting utility or electric utility that joins a [RTO/ISO]*."[52] Therefore, the Commission should not restrict the availability of the RTO Participation Adder to utilities that join RTOs/ISOs voluntarily – it would be inconsistent with the statute and would disregard the customer benefits that RTO/ISO membership provides

---

removed it from its regional transmission expansion plan due to revised load forecasts); *see also PJM Interconnection, L.L.C.*, 152 FERC ¶ 61,254 (2015) (making the same finding for Baltimore Gas and Electric's costs associated with its abandonment of the Mid-Atlantic Power Pathway Project). In both cases, the Commission found that the utilities were eligible to recover 100 percent of the prudently-incurred costs expended after the issuance of the Commission's order granting the abandoned plant incentive; however, the Commission further found that they were entitled to recover only 50 percent of their prudently-incurred costs expended before that date. As discussed in section II.D.2.a below, it is difficult for a utility to determine when it should (or need not) apply for the abandoned plant incentive under the current process, especially when the decision to cancel the transmission project in question lies with the RTO/ISO. As a result, transmission-owning RTO/ISO members are at risk for stranded costs associated with abandonments that are completely outside of their control.

[52] 16 U.S.C. § 824s(c) (2012), emphasis added.

and the risks it entails, benefits and risks that exist regardless of the circumstances under which a utility initially joined.[53]

Finally, eliminating or modifying the RTO Participation Adder would undermine regulatory certainty. Those utilities that have joined and/or participated in the further integration of the RTOs/ISOs since the issuance of Order No. 679 did so with the reasonable expectation that they would receive a 50 basis point adder to their base ROE for the duration of their membership. And the utilities that were part of RTOs/ISOs before the issuance of Order No. 679 have reasonably come to rely on the availability of the RTO Participation Adder when making their investment decisions. For example, such utilities have accepted the RTO/ISO as the Order No. 1000 regional planner (in lieu of other potential arrangements) based in part on the expectation that the RTO Participation Adder would be continued. They have also continued to participate in RTO projects that further integrate themselves into the RTO/ISO, rendering an exit more costly, whereas they might not have continued such further participation absent an expectation that the RTO Participation Adder would continue. Eliminating (or even modifying) the RTO Participation Adder now would upset those expectations, creating uncertainty about the benefits to a utility of joining or remaining in an RTO/ISO. Such action would effectively diminish the incentives for transmission-owning RTO/ISO members to remain in an RTO/ISO and discourage utilities that have yet to join an RTO/ISO from doing so given the risks involved.

In sum, the Commission should continue to make the 50 basis point RTO Participation Adder available to transmission-owning RTO/ISO members, regardless of whether they are

[53] While a recent court decision calls into question the Commission's rationale in a specific proceeding for granting the RTO Participation Adder to a utility who is alleged to be required to join an RTO/ISO under state law, the court did not preclude the Commission from granting the RTO Participation Adder to utilities that are compelled to join an RTO/ISO. *Cal. Pub. Utils. Comm'n v. FERC*, 879 F.3d 966 (9th Cir. 2018).

required to join. The RTO Participation Adder should apply to their entire transmission rate base for the duration of their membership. The current value of the RTO Participation Adder (i.e., 50 basis points) strikes an appropriate balance between the interests of utilities and the interests of their customers; it fairly compensates utilities for the risks that RTO/ISO membership entails in the context of the significant customers benefits that membership provides. Retaining this incentive in its current form will continue to incent RTO/ISO participation to the benefit of customers, consistent with the stated intent of FPA section 219.

b. Advanced Technology

In Questions 67 through 69, the Commission poses questions about ROE adders for advanced technologies. As explained in section II.C.1 above, Exelon opposes incentives granted solely on the basis of a transmission project's type or characteristics. However, to the extent that the deployment of an advanced technology provides benefits, then the Commission should consider those benefits when evaluating incentive applications. As discussed in section II.A above, no additional transmission incentives beyond those that the Commission already offers are needed to better encourage the development of new technologies, including the deployment of electric storage resources as transmission assets. What is important is the Commission's willingness to functionalize assets that serve a transmission function (including electric storage resources[54]) as transmission, providing an opportunity for the asset owner to recover its costs.[55]

---

[54] *See Exelon Corporation*, Post-Technical Comments of Exelon Corporation, Docket No. AD16-25 (filed Dec. 14, 2016). Here, Exelon argued that electric storage resources whose primary intended use and capabilities are to provide transmission service should be treated as transmission assets (with their costs included in transmission rates) and set forth the principles that it argued should govern their use as such. *Id.*, at 2-11.

[55] For example, the Commission found that the ComEd Superconductor Project is properly functionalized as transmission plant, stating that "[a]lthough the Project nominally operates at a significantly lower voltage than conventional transmission facilities, the lower voltage is indicative of the benefits of using superconductor cable rather than the capacity or purpose of the Project." ComEd Superconductor Order, 167 FERC ¶ 61,173 at P 27.

2. Non-ROE Transmission Incentives

a. Recovery of the Cost of Abandoned Plant

In Question 77, the Commission asks whether it should grant the abandoned plant incentive automatically and, if so, under what circumstances. Under the Commission's existing policies, a utility may seek to recover 100 percent of the prudently-incurred costs for a transmission project that is cancelled or abandoned due to factors beyond its control for only those costs that it expends after the effective date of the Commission order granting the project the abandoned plant incentive.[56] For prudently-incurred costs expended before that date, the utility is eligible to seek recovery of only 50 percent of its prudently-incurred costs should the project be cancelled or abandoned. To reduce regulatory burden and better reflect a utility's ability to decide whether to undertake a particular transmission project, the Commission should revise its policy to automatically allow a utility to seek to recover 100 percent of its prudently-incurred costs for certain types of transmission projects. Specifically, Exelon recommends that, for transmission projects that a utility is required to build (whether pursuant to an RTO/ISO governing agreement[57] or a relevant regulatory authority's directive), the Commission should automatically allow a utility to seek to recover 100 percent of its prudently-incurred costs if that project is cancelled or abandoned due to factors beyond the utility's control. While a utility would still be required to seek such recovery through an FPA section 205 filing (demonstrating the prudence of the costs incurred), which the Commission would then evaluate on a case-by-case basis,[58] the utility would no longer be required to file for the abandoned plant incentive for

---

[56] *San Diego Gas & Electric Co. v FERC*, 913 F.3d 127, 137-138 (D.C. Cir. 2019).
[57] Such projects would include transmission facilities that an incumbent transmission owner is required to build to support another transmission developer's project, such as substation or transmission line upgrades.
[58] *See* Order No. 679, 116 FERC ¶ 61,057 at PP 165-166.

each and every project in advance of abandonment to be eligible to seek to recover 100 percent of its prudently-incurred costs for such projects.

When initially establishing the policy that 50 percent of prudently-incurred costs for a cancelled project are eligible for recovery from ratepayers (while the remaining 50 percent must be borne by the utility's shareholders) the Commission's intent was to equitably balance the interests of ratepayers and investors.[59] Specifically, the Commission found that:

> [u]tility management, acting on behalf of its investors and its ratepayers, is the entity which actually makes the original investment decision as well as the subsequent decision to cancel. Consequently, imposing some of the risk of abandonment on the utility, [sic] provides an incentive for utility decisionmakers to more carefully weigh the potential risk of cancellation before embarking on a construction project.[60]

Thus, the Commission's policy on the recovery of abandoned plant costs was intended to incent utility decisionmakers to carefully weigh the risks associated with a project before making any investment decision.

Consistent with the that rationale, the Commission should allow utilities to seek to recover 100 percent of their prudently-incurred costs for a transmission project that they were directed to build (whether by an RTO/ISO or relevant regulatory authority) without first seeking authorization to do so from the Commission.[61] Such an expansion recognizes that, where the utility does not have any choice in the original investment decision, requiring its shareholders to

---

[59] *See New England Power Co.*, Opinion No. 295, 42 FERC ¶ 61,016 at 61,068, 61-081-61,083 (1988); *order on reh'g*, 43 FERC ¶ 61,285 (1988) (Opinion No. 295-A).
[60] Opinion No. 295-A, 43 FERC ¶ 61,285 at 61,780.
[61] The Commission has made exceptions to the policy it set forth in Opinion 295 on abandonment in individual cases. *See Southern California Edison Co.*, 112 FERC ¶ 61,014, at PP 58-61 (2005), *reh'g denied*, 113 FERC ¶ 61,143, at P 9-15 (2005) (together, Southern California Edison Orders). In these orders, the Commission found that Southern California Edison should be eligible to seek recovery of 100 percent of its prudently-incurred costs in case of abandonment due to factors beyond its control where it undertook a transmission project pursuant to a state regulatory authority's order, further noting that "the [California Public Utilities Commission], not [Southern California Edison], makes the decisions regarding the ultimate design of the Antelope Project." *Id.*, P 9.

bear 50 percent of prudently-incurred costs would be unfair and ineffective. Specifically, when utilities are directed to develop certain transmission facilities by an RTO/ISO or relevant regulatory authority, their management has no authority over the decision to pursue the project, nor can they dictate its scope, timing, or nature. As a result, it would be unfair to require them to bear the risks associated with cancellation or abandonment due to factors beyond their control – they had no opportunity in the first instance to weigh those risks in their investment and design decisions. Moreover, requiring shareholders to bear 50 percent of the costs of a project that the utility has no choice but to build does not affect the utility's investment decision – as the utility must build, there is no incentive for it to more carefully weigh the risks of cancellation or abandonment before proceeding with a transmission project's development.

Although utilities have the opportunity to achieve this same outcome (i.e., eligibility to seek to recover 100 percent of prudently-incurred abandoned plant costs) by applying for the abandoned plant incentive under the Commission's existing incentives policy framework, requiring such applications is burdensome, time-consuming, and fraught with risks. Specifically, it forces the utility to assess how likely it is that each transmission project it is directed to undertake will be cancelled or abandoned due to factors beyond its control and to weigh that probability against the costs associated with the time and resources needed to file an incentive application with the Commission for each relevant project. Given the significant uncertainty involved in those calculations of risk, which is only heightened by the fact that the decision to cancel or abandon the transmission project lies with the RTO/ISO or relevant regulatory authority and not with the utility, it is difficult for a utility to determine when it should (or need not) apply for the abandoned plant incentive under the current process. And waiting until the utility is reasonably certain that a transmission project will be cancelled or abandoned is not an option because the abandoned plant incentive only applies to prudently-incurred costs expended after the effective date of the Commission order granting the incentive. For these reasons, the Commission should allow utilities that are directed to undertake a transmission project, whether by an RTO/ISO or a relevant regulatory authority, to seek to recover 100 percent of their prudently-incurred costs for a transmission project cancelled or abandoned due to factors beyond their control without first applying for the abandoned plant incentive.

In Question 78, the Commission inquires whether the abandoned plant incentive encourages transmission developers to pursue unnecessarily risky transmission projects or take unnecessary risks in transmission development. Exelon does not believe that the abandoned plant incentive incents utilities to take unnecessary risks. The abandoned plant incentive only applies to prudently-incurred costs – a utility cannot take imprudent risks and risks disallowance of the associated costs if it does so. Thus, the Commission's review of the prudence of costs incurred associated with the abandoned plant discourages unnecessarily risky behavior.

E. Mechanics and Implementation

1. Duration of Incentives

In Questions 83 and 84, the Commission asks whether it should limit the duration of the transmission incentives that it grants and, if so, how. Limiting the duration of transmission incentives would be unreasonable and counterproductive. The benefits of a transmission project (which should be a focus of the Commission's evaluation of incentive applications) are not time limited – as long as the transmission infrastructure is in place, it will continue to provide benefits. Moreover, limiting the duration of an incentive could diminish its effectiveness in supporting transmission development. If the Commission establishes clear rules about how long an incentive that it has granted will remain in place (and to do otherwise would create uncertainty that would undermine the purpose of incentives), utilities and investors will take the limited duration of the incentive into consideration when making investment decisions, discounting the effects of the incentive accordingly. Cutting off an incentive will not incent as much.

In Question 85, the Commission inquires whether it should eliminate or modify a transmission incentive that it has granted if there is a material change to the associated transmission project. As a general rule, Exelon believes that the need for regulatory certainty dictates that once the Commission has granted an incentive, it should not eliminate or modify that incentive absent extraordinary circumstances. Retaining an incentive despite a material change to the transmission project for which it was awarded could help support needed transmission development (e.g., a project is scaled down because it is no longer needed to address a NERC reliability standard violation, but nevertheless continues to provide important local reliability and resilience benefits). Thus, the Commission should allow itself the discretion to decide such issues on a case-by-case basis in light of the facts and circumstances that each case presents.

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

In Questions 90 through 92, the Commission asks whether it should modify its current approach of granting incentives on a case-by-case basis. For almost all of the existing incentives, ruling on incentive applications on a case-by-case basis provides the Commission with maximum flexibility to consider the unique facts and circumstances of each transmission project; this outweighs the uncertainty created by the lack of a more definitive set of rules around the transmission projects that merit incentives. Flexibility allows the Commission to evaluate the benefits and risks and challenges of each transmission project, tailoring incentives to best promote needed and valuable transmission investments. Thus, the Commission should retain its current approach of evaluating incentive applications on a case-by-case basis, with one exception – the abandoned plant incentive is more appropriately granted automatically for any transmission project that a utility is directed to build (whether by an RTO/ISO or relevant regulatory authority) for the reasons discussed in section II.D.2.a above.

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

In Question 93, the Commission asks whether it should establish a more formulaic framework for determining the appropriate level and combination of incentives. Exelon believes that such a framework would undermine the Commission's goal (and the FPA section 219 mandate) to incent beneficial transmission infrastructure investment. Regardless of whether a more formulaic framework might provide greater certainty as to the level and combination of incentives that an applicant could expect for a particular transmission project, our concerns with the lack of flexibility that such an approach would provide for both the Commission and applicants outweighs the benefits that increased certainty would bring. Specifically, a more formulaic approach could prevent the Commission from determining the appropriate level and combination of incentives based on the totality of the facts and circumstances of each case – it would inappropriately limit the Commission's discretion to support beneficial transmission projects and to decline to grant incentives to transmission projects that may not merit them. There is, however, one exception; as discussed in section II.D.2.a above, the abandoned plant incentive should be granted automatically for any transmission project that a utility is directed to build (whether by an RTO/ISO or relevant regulatory authority).

In Question 94, the Commission asks how it could provide more detailed explanations in individual cases that would better describe how it derives the appropriate level and combination of incentives. Again, Exelon does not believe that any changes to the Commission's current approach of granting incentives on a case-by-case basis are warranted (other than for the abandoned plant incentive, as discussed in section II.D.2.a above). As long as the Commission's determinations are sufficiently supported by the record before it and the Commission explains how the facts and circumstances of each case are relevant to its determinations, the Commission's orders will provide adequate guidance for future incentive applicants.

4. Bounds on ROE Incentives

In Questions 96 and 97, the Commission asks whether the Commission should retain discretion to determine the appropriate level of ROE incentive adders and, if so, whether its discretion should be bound within a predetermined range. Exelon believes that the Commission should retain its current level of discretion, without any imposition of a predetermined range for ROE incentive adders. While Exelon acknowledges that less discretion would provide greater certainty about the level of ROE incentive adder that the Commission is likely to grant a particular transmission project, we believe that Commission discretion to evaluate the benefits that a project provides without constraint will allow the Commission to best support needed and beneficial transmission development. Limiting the Commission's discretion to consider the specific facts and circumstances surrounding a transmission project for which the developer has requested an ROE incentive adder could result in a needed and beneficial project being ineligible for incentives (or for the level of ROE incentive adder that it requests) because it does not meet whatever threshold that the Commission has established to limit its discretion. For Exelon, this risk outweighs the benefits that greater regulatory certainty would provide.

Moreover, such thresholds could quickly become outdated as the industry continues to evolve and technology continues to advance. As we note elsewhere in our comments, incentives can drive the adoption of advanced technologies and innovative transmission solutions. If the Commission were to limit its discretion to determine the appropriate level of ROE incentive adder on a case-by-case basis, it could erect regulatory barriers to transmission projects that are unconventional in a way that renders them ineligible to receive an ROE incentive adder (or an ROE incentive adder at the level they request) under whatever criteria the Commission adopts to limit its discretion, even if a project offers significant benefits that would merit such incentive. Thus, we recommend that the Commission continue to have the discretion to grant ROE incentive adders at any level it deems appropriate given the specific facts and circumstances of the application before it.

F. Metrics for Evaluating the Effectiveness of Incentives

In Question 98, the Commission asks what metrics the Commission should use to measure the effectiveness of incentives. Exelon understands the Commission's desire to ensure that its incentives policies are working to promote needed transmission investment. However, we caution the Commission against overreliance on metrics. It is almost impossible to ascertain whether a particular transmission project would have been built "but for" incentives. There are a wide range of factors that go into investment decisions, and incentives are but one piece of a much larger puzzle. Without all of those pieces in place, investors may be unwilling to move forward with a transmission project, even if the Commission has granted it incentives. The better question for the Commission to study is whether the transmission infrastructure being planned and built is benefiting customers, the purpose of granting incentives in the first place.

In Question 101, the Commission inquires whether it should require incentive recipients to report the primary driver of the transmission projects for which they have received incentives, as well as the risks entailed in their development. To the extent that the Commission adopts additional information requirements, Exelon suggests that there are limitations to the usefulness of the information that the Commission would collect. For example, certain requirements might not appropriately apply to transmission projects that have received certain types of incentives. If the Commission granted risk-reducing incentives to a transmission project based solely on the risks and challenges that it faces, whether that project was planned primarily to enhance reliability or to reduce congestion is not necessarily informative. In any case, transmission projects often fulfill multiple needs, so identifying the primary driver may not fully capture the benefits that a project is intended to provide. And without a preestablished list of primary drivers, utilities might report the drivers of transmission projects intended to provide similar benefits differently, further limiting the usefulness of the information. In terms of the risks that a transmission project faces, the number or types of risks alone is not necessarily reflective of their magnitude, nor is helpful for the Commission to have this information if the applicant relied on the benefits of its project to justify its incentive request.

Moreover, imposing additional reporting requirements could be unduly burdensome, especially given that the information that the Commission uses in its question as examples is readily available through other channels. Specifically, the primary drivers of a transmission project and the risks and challenges entailed are described in detail in an incentive application. The primary driver of a transmission project is also made publicly available through local and/or regional transmission planning processes. As a result, the Commission already has sufficient access to the information that it lists as examples in the question; any additional information requirements that the Commission imposes should not be duplicative of other information provision requirements (such as those associated with the transmission planning process or incentive applications).

In Question 102, the Commission asks whether it should require additional data on abandoned transmission projects, such as the reasons for which they failed. Exelon notes that this data would already be included in any FPA section 205 filing that the incentive applicant made to recover its abandoned plant costs. And to the extent that there is no such filing, then either the transmission project entered service or there is no need for the Commission to have information about why a transmission project failed given that the applicant will not collect any costs from customers. Thus, Exelon believes that additional reporting requirements are unnecessary and would be unduly burdensome and duplicative.

III. CONCLUSION

In conclusion, the Commission does not need to adopt additional new incentives or substantially revise its existing framework for evaluating incentive applications to support needed and beneficial investment. Instead, the Commission should focus its limited time and resources on providing regulatory certainty through fair, timely, and flexible performance of its statutory duties in the ordinary course of business. Refinements to its existing incentives policies could also help to better support transmission development. Specifically, the Commission should consider a transmission project's benefits (along with the risks and challenges that it faces) when evaluating incentive applications. It should also allow utilities to seek to recover 100 percent of their prudently-incurred costs for a transmission project that they were directed to build (whether by an RTO/ISO or relevant regulatory authority) without first seeking authorization to do so from the Commission.

Respectfully submitted,

/s/ Christopher A. Wilson
Christopher A. Wilson
Director, Federal Regulatory Affairs
Exelon Corporation
101 Constitution Ave., N.W.,
Suite 400 East
Washington, DC 20001
Telephone: 202-347-7500
FERCe-Filings@exeloncorp.com

Amy L. Blauman
Associate General Counsel
Exelon Corporation
701 Ninth Street, NW
Suite 1100
Washington, DC 20068
Telephone: 202-872-2122
albaluman@pepcoholdings.com

Dated: June 26, 2019

Document Content(s)