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June 30, 2021

Via eTariff Filing
Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

RE: PJM Tariff Revisions to Implement Transmission Owners' Funding of Network Upgrades, Docket No. ER21-2282-000

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] Part 35 of the Federal Energy Regulatory Commission's regulations,[2] and Section 9.1(a) of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("PJM Tariff"), the PJM Transmission Owners,[3] acting through the PJM Consolidated Transmission Owners Agreement ("CTOA"),[4] hereby submit proposed revisions to the PJM Tariff to provide Transmission Owners with the option to elect to fund the capital cost of Network Upgrades[5] necessary to accommodate generator interconnections ("Proposed Revisions").[6] As explained further herein, the Proposed Revisions allow the PJM Transmission Owners the opportunity to earn a return of and on the

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[1] 16 U.S.C. § 824d.

[2] 18 C.F.R. Part 35.

[3] Capitalized terms used herein, that are not otherwise defined herein, shall have the meaning provided in the PJM Tariff, CTOA or Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.

[4] The amendments to the PJM Tariff described herein, and certain implementation revisions made in response to PJM's comments, were authorized pursuant to the individual and weighted voting requirements in Section 8.5 of the CTOA on June 9, 2021 and June 25, 2021, respectively.

[5] The term "Network Upgrades" as used in this filing refers to the Network Upgrades required to accommodate the interconnection of generators to the transmission system.

[6] Pursuant to Order No. 714, this filing is submitted by PJM on behalf of the PJM Transmission Owners as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, the PJM Transmission Owners have requested PJM submit the Proposed Revisions in the eTariff system as part of PJM's electronic Intra PJM Tariff.

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costs of Network Upgrades that are necessary to interconnect generation resources to the PJM transmission system. As explained below, the PJM Transmission Owners' filing is just and reasonable and conforms to the Commission's interconnection pricing policy in Order No. 2003[7] and recent judicial and Commission precedents.

The PJM Transmission Owners respectfully request that the Commission approve the Proposed Revisions without hearing, modification or condition, to be effective sixty-one days from the date of this filing or August 30, 2021. To the extent necessary, the PJM Transmission Owners respectfully request waiver of any regulation necessary for the Commission to accept the Proposed Revisions as filed and grant the requested effective date.

I. INTRODUCTION

As a result of recent public policy initiatives focused on promoting the development of clean, renewable generation resources to mitigate climate change issues, PJM has experienced a sharp increase in the number of generation resources seeking to interconnect to the transmission system. As of December 2020, PJM had approximately 1,600 generation projects under active study in the PJM interconnection queue.[8] The 2020 PJM Regional Transmission Expansion Plan ("RTEP") shows that the total estimated Network Upgrade costs required to reliably interconnect new generating resources in PJM is approximately $6.5 billion.[9] This figure includes approximately $1.565 billion of Network Upgrades already constructed and in-service, as well as approximately $4.9 billion of Network Upgrades associated with active projects in the queue.

Indeed, even if a fraction of the $4.9 billion of Network Upgrades in the active category were to move forward and be constructed, this would represent a significant escalation of the $1.565 billion of Network Upgrades currently owned or operated by the PJM Transmission Owners and for which they are currently not earning a return. This trend will continue as the number of new generation interconnection requests is expected to increase significantly, if not exponentially, in the coming years as the electric power industry continues to accelerate the development and construction of clean renewable energy resources.

The PJM Transmission Owners strongly support the generation transformation that is currently underway in PJM and the ongoing stakeholder efforts in PJM to improve the generation interconnection process to facilitate this change. However, the proliferation of new generation

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[7] *Standardization of Generator Interconnection Agreements & Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 579 (2003) ("Order No. 2003"), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 (2004), *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

[8] *See PJM Interconnection L.L.C., Informational Report on Interconnection Study Performance Metrics,* Docket No. ER19-1958-003 (filed Feb. 16, 2021).

[9] *See PJM 2020 Regional Transmission Expansion Plan*, Executive Summary at 4 (Feb. 28, 2021), https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx.

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interconnection requests and the resulting increase in Network Upgrades required to interconnect those generators to the transmission system has exacerbated a flaw with the funding model in PJM for Network Upgrades (referred to herein as "Existing Funding Model"). This flaw requires an immediate fix. Under the Existing Funding Model, the PJM Transmission Owners are able to recover their operation and maintenance ("O&M") expenses for Network Upgrades, but they earn no return or profit on those Network Upgrades. As demonstrated in the supporting affidavits of Mr. David W. Weaver, Vice President of Transmission Strategy at Exelon ("Weaver Affidavit") and Messrs. David Hunger and Seabron Adamson of Charles River Associates. ("Hunger and Adamson Affidavit"), owning and operating Network Upgrades entails significant risks for the PJM Transmission Owners, and because the Existing Funding Model provides no return or profit on these Network Upgrades, there is no compensation to the PJM Transmission Owners and their shareholders for these risks.

The failure to properly balance the risk of owning and operating increasing levels of Network Upgrades with adequate compensation for the PJM Transmission Owners violates general ratemaking standards and the principles established by the U.S. Supreme Court in *Hope* and *Bluefield.*[10] Indeed, in a recent 2018 decision by the D.C. Circuit (*Ameren Servs. Co. v. FERC*, 880 F.3d 571 (D.C. Cir. 2018) ("*Ameren*")), the Court of Appeals for the District of Columbia addressed the unfairness of a similar funding model in Midcontinent Independent System Operator, Inc. ("MISO") and found that it required transmission owners (and their shareholders) to accept "incremental exposure to loss with no corresponding benefit."[11] In that proceeding, the court stressed that the Commission cannot force a transmission owner to operate even a portion of its business on a non-profit basis.[12]

When the Commission approved the Existing Funding Model in PJM, the impact on the PJM Transmission Owners from the failure of that model to provide a return or profit on Network Upgrades was minimal due the limited number of Network Upgrades on the transmission system and generation interconnection requests in the PJM interconnection queue at the time. As noted below, the impact has significantly grown as the number of Network Upgrades on the PJM system has increased. As the number of Network Upgrades has grown, the corresponding risk of owning and operating those facilities has also increased. The anticipated increase in Network Upgrades over the next several years makes the continuation of the Existing Funding Model unsustainable. To address this problem, the PJM Transmission Owners submit the Proposed Revisions to provide them with the option to elect to provide initial funding for Network Upgrade costs to earn a return on those facilities in conformance with Order No. 2003 and recent judicial and Commission precedent. The PJM Transmission Owners' proposal is modeled on the transmission owner funding proposal that the Commission recently approved in MISO.[13]

[10] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

[11] *Ameren* at 580-81.

[12] *Id.* at 582.

[13] *Midcontinent Indep. Sys. Operator, Inc.*, 171 FERC ¶ 61,075 ("*April 2020 MISO FSA Order*"), *reh'g order,* 173 FERC ¶ 61,037 (2020) ("*October 2020 MISO FSA Rehearing Order*") (approving the new *pro forma* Facilities

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The key components of the PJM Transmission Owners' Proposed Revisions are: (1) a new section 217.8 to the PJM Tariff that sets forth the process and rules governing how and when a transmission owner could elect to fund Network Upgrades; and (2) a *pro forma* Network Upgrade Funding Agreement ("NUFA") that provides standard terms and conditions for the recovery of the return of and on the capital funding for the upgrades. The NUFA also includes a formula rate similar to the formula rate approved in MISO. The PJM Transmission Owners respectfully request that the Commission accept the Proposed Revisions as just and reasonable and consistent with Order No. 2003 and recent judicial and Commission precedent without hearing, modification, or condition, and allow the Proposed Revisions to become effective sixty-one days from the date of the filing or August 30, 2021.

II. BACKGROUND

A. Order No. 2003's Crediting Policy Allows Transmission Owners to Earn a Return on the Costs of Network Upgrades but the Existing Funding Model in PJM Does Not.

In Order No. 2003, the Commission standardized its procedures for generator interconnections. Under the standardized procedures, transmission owners are obligated to expand their transmission systems by building, owning, and operating all Network Upgrades necessary to accommodate new generator interconnections, and are allowed to earn a return of and on the costs of those Network Upgrades. In particular, Order No. 2003 requires interconnection customers to initially fund Network Upgrades and then establishes a crediting policy to reimburse interconnection customers for these costs. Specifically, the interconnection customer provides the upfront funding for the Network Upgrades and is "entitled to a cash equivalent refund . . . equal to the total amount paid for the Network Upgrades." To provide this refund, the transmission owner credits the amount that the interconnection customer has paid for the Network Upgrades against its charges for transmission service.[14] To the extent that a transmission owner has provided transmission credits to the interconnection customer, Order No. 2003 allows the transmission owner to include the costs of the Network Upgrades in its rate base, thereby earning a return on those costs.[15]

Prior to Order No. 2003, PJM adopted a participant funding model for Network Upgrades required to interconnect new generation to the PJM system. Specifically, under this model, the interconnection customer is responsible for paying upfront the costs of any Network Upgrades

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Service Agreement, which provides a standard agreement for use when a transmission owner elects the transmission owning initial funding option).

[14] Order No. 2003, 104 FERC ¶ 61,103 at P 676. These credits are referred to in Order No. 2003 as "transmission credits." *Id*. at P 677.

[15] *See* Order No. 2003, 104 FERC ¶ 61,103 at P 28; Order No. 2003-A, 106 FERC ¶ 61,220 at P 657 (finding that a transmission provider may include the costs of Network Upgrades in its rates after it has provided credits to the Interconnection Customer). *See also Reform of Generator Interconnection Procedures & Agreements,* Order No. 845-A, 166 FERC ¶ 61,137 at P 19 ("Order No. 845-A"), *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019) ("Order No. 845-B").

needed to interconnect to the PJM transmission system.[16] In its Order No. 2003 compliance filing submitted on January 20, 2004 in Docket No. ER04-457-000, PJM sought to continue its participant funding model for generator interconnections. Specifically, PJM requested, and the Commission granted, an independent entity variation for PJM to depart from the default Order No. 2003 crediting policy in favor of the participant funding model that is often referred to as a "but for" funding mechanism for interconnections of new generation resources. PJM stated that this funding construct for Network Upgrades would send the appropriate price signals for siting new generation resources.[17] However, the Existing Funding Model, adopted in 2004, failed to compensate PJM Transmission Owners for owning and operating Network Upgrades.

When PJM submitted its Order No. 2003 compliance filing in 2004, the number of generator interconnection projects were significantly smaller than the number today. The Existing Funding Model at the time imposed minimal risks upon the PJM Transmission Owners, as the RTEP included only the addition of 10,700 MW of new generation to its system and approximately 4,500 MW of new generation under construction. PJM was also processing only 55 new interconnection requests in the PJM interconnection queue compared to the approximately 1,600 as of December 2020.[18] But as the number of generator interconnections have increased significantly in PJM, so too have the risks faced by the PJM Transmission Owners.[19]

B. Growing Public Policy Support Has Driven A Significant Increase in the Number of Renewable Projects Seeking to Interconnect to the PJM Transmission System.

Since the Commission approved PJM's Order No. 2003 compliance filing, the electric industry has undergone profound changes and the nation is in the midst of a transformation with respect to its energy resource mix.[20] Many states have adopted public policies that promote the

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[16] *See* Answer of PJM Interconnection, L.L.C. to Comments and Protests, Docket No. ER04-457-000 at 4 (filed Feb. 25, 2004) ("PJM 2004 Answer").

[17] PJM 2004 Answer at 5 ("PJM provides a meaningful incentive to developers to install generation in locations on the system where existing transmission capacity is less than fully utilized and where, therefore, the generator's capacity can be added with relatively less costly improvements of the transmission system.").

[18] PJM 2004 Filing, Transmittal Letter at 4-5 (explaining that under the PJM Tariff, "PJM evaluates generation interconnection requests and the transmission facilities required to accommodate such interconnections are incorporated into PJM's Regional Transmission Expansion Plan").

[19] Hunger and Adamson Affidavit at 11-13 (noting that to achieve federal and state clean energy goals will require a large amount of new renewable energy generation to be interconnected across the PJM footprint).

[20] The Commission has noted that the nation's resource mix has significantly evolved over the past fifteen years. According to the Commission, in 2006, coal, natural gas, and nuclear made up approximately 88 percent of electric generation in the U.S. with coal contributing almost 50 percent. However, by 2018, coal, natural gas and nuclear represented 82 percent of electric generation, with 27 percent of total generation coming from coal and 36 from natural gas. With respect to renewable resources, in 2006, solar and wind represented one percent of electric generation, which increased to eight percent by 2018. *See Electric Transmission Incentives Policy under Section 219 of the Federal Power Act,* Notice of Proposed Rulemaking,170 FERC ¶ 61,204 at P 27 (2020) ("*Transmission Incentives NOPR*"). *See also* Hunger and Adamson Affidavit at 11 (stating that the United States is making changes

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development of renewable energy resources, and the states in the PJM footprint are no exception. Indeed, some states within the PJM footprint have some of the most aggressive Renewable Portfolio Standard (RPS) in the country.[21] The Commission recognizes that significant changes have taken place in the electric power industry, noting that "the landscape for planning, developing, operating, and maintaining transmission infrastructure has changed considerably," including a rapid evolution in resource mix.[22]

This energy grid transition results in a growing number of new resources interconnecting to the transmission system in PJM. According to PJM, there is an "unprecedented capacity shift driven by federal and state public policy and broader fuel economics" and "PJM's interconnection process is showing trends of increasing renewable generation."[23] As previously noted, PJM's most recent interconnection report shows a significant increase in the number of generation projects in the queue over the past several years.[24] According to PJM's presentation to stakeholders in October 2020, there were approximately 1,600 active interconnection projects in the PJM queue, totaling approximately 147,000 MW in new generation capacity. As the chart below shows, approximately 80 percent of those projects are new solar, wind, and storage facilities.[25]

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in federal and state policies to transition from a fossil-dominated generation fleet to new renewable generation and storage resources).

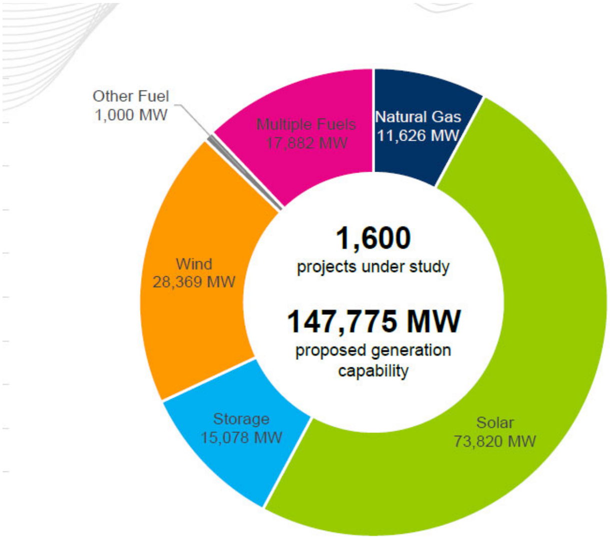
[21] For example, New Jersey's RPS requires each electricity supplier serving retail customers to procure 50 percent of the electricity it sells in New Jersey from quantified renewable resources by 2030. The District of Columbia has increased its RPS target to 100 percent by 2032. *See* Hunger and Adamson Affidavit at 11-13 (providing a detailed list of the state renewable goals in the PJM footprint).

[22] *See* Transmission Incentives NOPR, 170 FERC ¶ 61,204 at P 27 (noting that solar and wind represented one percent of the nation's resource mix in 2006 but increased to eight percent in 2018).

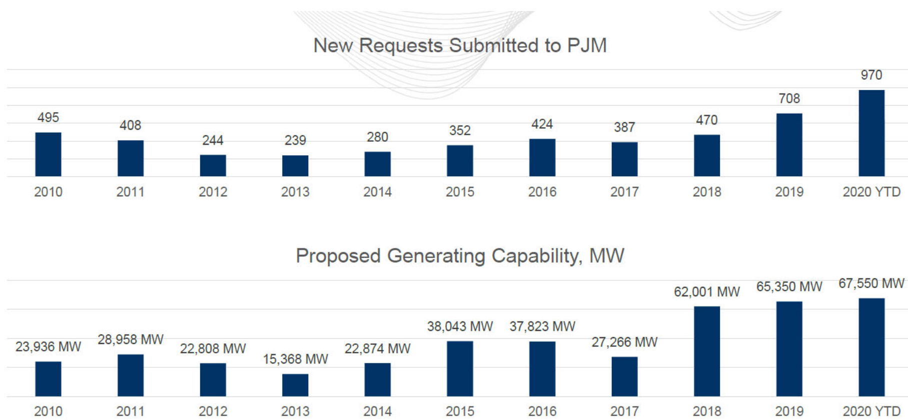
[23] 2020 RTEP, Executive Summary at 4.

[24] *PJM Interconnection, L.L.C.*, Informational Report on Interconnection Study Performance Metrics, Docket No. ER19-1958-003, at 1-2 (stating that "PJM has been experiencing an increase in the number of New Service Request received each year leading to a record-high volume of projects under study," that "there were 1,029 New Service Requests submitted from January 1, 2020 through December 31, 2020," and that PJM "now has 1,618 active projects at various points in the study process."). In the report, PJM stated that the "remarkable increases" in new generator interconnection requests is driven by Congress' recent extension of the Production Tax Credits and Investment Tax Credits for renewable resources, as well as other factors, including state renewable portfolio standards, state incentive programs and decreasing costs for inverter-based technology." *Id.* at 6. Indeed, the number of active generator interconnection requests under study in PJM continue to increase significantly. PJM's current interconnection queue has approximately 2,000 projects (708 in the feasibility study phase, 486 in the system impact phase, and 803 in the facilities study phase). *See* www.pjm.com/phanning (last visited June 24, 2021). *See also* Hunger and Adamson Affidavit at 14-15 (demonstrating the increase in generator interconnection request in recent years).

[25] *See* PJM's October 2020 Presentation titled "*Interconnection Process Overview*" by Jason Connell & Susan McGill at 32. *See also* Hunger and Adamson Affidavit at 15 (showing the overwhelming majority of generator interconnection requests over the past five years have been from renewable generation resources).



While these numbers are impressive by themselves, it is important to note that the large numbers of generation projects in the PJM interconnection queue reflects a trend of growth over the past few years. As charts below show, in 2017, there were only 387 new generator interconnection requests. In 2020, this number increased to 970. Not surprisingly, the increase in requests is accompanied by a corresponding increase in the proposed generation capacity seeking to interconnect to the transmission grid in PJM from 23,936 MW in 2010 to 67,550 MW in 2020.



While the increase in generation development, particularly renewable generation development, is a benefit to PJM customers, the PJM transmission system was not designed to accommodate the significant growth in generation resources.[26] Accordingly, the increasing amount of generation seeking to interconnect to the PJM system requires a significant build out

[26] *See* Weaver Affidavit at 3 (because of the limited excess transmission capacity on the PJM transmission system, Network Upgrades are needed to accommodate many new generator interconnections in PJM).

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of the transmission system, including Network Upgrades. Indeed, as of the end of 2020, there were approximately $4.9 billion of active Network Upgrades in the PJM RTEP.[27]

The PJM Transmission Owners strongly support efforts to interconnect new clean energy resources to the electric grid. However, as discussed herein, the growing number of Network Upgrades places untenable financial pressure on the PJM Transmission Owners who own and operate these Network Upgrades with no compensation for the risks associated with doing so.[28] This financial pressure imposed on the PJM Transmission Owners is likely to increase due to new state and federal policies supporting further renewable generation development.[29] The Biden Administration recently announced that the United States will seek to reduce emissions by 50 to 52 percent by 2030 compared to 2005 levels and underscored "America's commitment to leading a clean energy revolution."[30] In the pursuit of this goal, the Biden Administration stated that the U.S. electric power sector will need to go further and work faster to transform its energy systems, including the development of renewable energy resources, such as solar energy, wind power, and electricity storage.[31] Messrs. Hunger and Adamson state that to meet a 2035 decarbonization target for PJM may require adding additional renewable generation on a "massive scale" – *i.e.*, equivalent to replacing the entire existing PJM generation system. In this connection, they note that the associated Network Upgrades, while difficult to predict accurately, could be in the many billions of dollars.[32] Thus, it is imperative that the PJM Transmission Owners fix the flaw with the Existing Funding Model and implement a mechanism that allows

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[27] "Active" projects refer to those projects that are in all study phases of the interconnection process. There are approximately $1.565 billion of Network Upgrades that are already built and in service. *See* 2020 Regional Transmission Expansion Plan (Feb. 28, 2021), Executive Summary at 4 (available at https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx. Not all of the $4.91 billion active Network Upgrades will be constructed because not all of the generation projects requiring those upgrades will ultimately move forward and interconnect to the PJM transmission system. In their Affidavit, Messrs. Hunger and Adamson explain that the percentage of projects in the queue moving towards completion depends upon the status of the project within the queue. Historically, the completion rate for a project that entered the interconnection queue has been around 20 percent (in the 2015 period). They state that within the past three years, this percentage has increased to approximately 23 percent. Hunger and Adamson Affidavit at 14. Thus, assuming that only 23 percent of the projects move forward (based upon completion rates over the past three years), this would mean roughly $1.13 billion of Network Upgrades would be added. This is a conservative assumption because projects that are in later stages of the generator interconnection study process have higher completion rates. Messrs. Hunger and Adamson point out that the percentage of projects that have reached the Facilities Study Phase moving toward to completion is 45 percent. They explain that this figure is relevant because as of May 2021, there are 782 projects representing over 44 gigawatts of capacity that have reached the Facilities Study Phase in PJM. *Id*. at 14.

[28] Hunger and Adamson Affidavit at 15-17.

[29] *Id*. at 11-12 (noting that PJM is largely dependent upon fossil-fired generation and that a large amount of new renewable resources will be needed in PJM in order to meet federal and state renewable and carbon emission reduction goals).

[30] *Fact Sheet: President Biden's Leaders Summit on Climate,* https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/23/fact-sheet-president-bidens-leaders-summit-on-climate/ (last visited June 22, 2021).

[31] *Id.*

[32] Hunger and Adamson Affidavit at 14-15.

them the opportunity to earn a return on Network Upgrades to compensate them for the risks associated with owning and operating these facilities.

C. The *Ameren* Decision and Recent Commission Orders Hold that a Transmission Owner Cannot Be Compelled to Own and Operate Network Upgrades and Incur Risks Without Compensation.

In *Ameren*, the D.C. Circuit questioned the lawfulness of denying transmission owners the opportunity to earn a return on Network Upgrades given the risks that they incur as the result of owning and operating those facilities.[33] In that proceeding, the D.C. Circuit addressed Commission orders regarding the MISO Transmission Owners' option to fund Network Upgrades.[34] The court ultimately remanded the Commission's orders for further proceedings. However, in doing so, the court made several key findings regarding the lawfulness of requiring transmission owners to own and operate Network Upgrades without the ability to earn a return or a profit on them.

Critically, the court found that the Commission may not "compel transmission owners to operate the upgrades without an opportunity to earn a return."[35] The court further stated that under "compelled generator funding," transmission owners are forced to assume certain costs for which they are never compensated.[36] Thus, in remanding the Commission's orders, the court instructed the Commission to be mindful of the fact that because "transmission owners will own and operate the grid, they will bear liability for insurance deductibles and all sorts of litigation, including environmental and reliability claims (such as blackout risks)."[37] The court also noted that under the participant funding model in MISO, "all costs, and risks, are not baked [into the existing compensation structure] – that, in fact, shareholders are forced to accept incremental exposure to loss with no corresponding benefit."[38]

Significantly, the court found that not allowing the MISO Transmission Owners to earn a return on Network Upgrades requires "the MISO Transmission Owners to act, at least in part, as a non-profit business. . . Put another way, by modifying the transmission owners' entire enterprise, [the Commission's] orders attack their very business model and thereby create a risk that new capital investment will be deterred."[39] The court stated that not allowing transmission owners to earn a return on Network Upgrades is in contravention of the Supreme Court

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[33] *Ameren* at 578-87.

[34] *See Midcontinent Indep. Sys. Operator, Inc. & Otter Tail Power Co. v. Midcontinent Sys. Operator, Inc.*, 151 FERC ¶ 61,220 (2015), *vacated and remanded sub nom*. *Ameren Servs. Co. v. FERC*, 880 F.3d 571; *Otter Tail Power Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 153 FERC ¶ 61,352, at PP 29-35, 55-65 (2015), *reh'g denied*, 156 FERC ¶ 61,099 (2016), vacated *and remanded sub nom*. *Ameren Servs. Co. v. FERC*, 880 F.3d 571.

[35] *Ameren* at 579.

[36] *Id.* at 580.

[37] *Id*.

[38] *Id.* at 580-81.

[39] *Id.* at 581.

precedent holding that "a regulated industry is entitled to a return that is sufficient to ensure that *new* capital can be attracted" and that "a utility's return must allow it to compete for funding in the financial markets."[40] The court vacated and remanded to the Commission its orders concerning interconnection financing procedures in MISO.

On remand, the Commission, reversed its decision and reinstated the tariff provision in MISO that allowed a transmission owner to unilaterally elect to fund generator interconnection Network Upgrades.[41] The Commission held that its prior orders were incorrect in a number of respects, stating:

> We find that the Commission erred in failing to (1) adequately address transmission owners' contention that the Commission's vacated orders would force them to construct and operate Generator Up-Front Funded network upgrades on a non-profit basis; (2) adequately address transmission owners' concerns that their investors would be forced to accept risk-bearing additions to their network with zero return; (3) offer sufficient evidence or economic theory to support the Commission's finding of discrimination by transmission owners' among their customers; and (4) address the effect of the Commission's orders on the ability of transmission businesses to attract future capital.[42]

The Commission concluded that "[u]pon further review of the record, we find that there was not enough evidence to sustain the Commission's findings in the vacated orders.[43]

In orders issued subsequent to *Ameren*, the Commission approved a *pro forma* agreement to allow the MISO Transmission Owners to collect the return of and on the capital used to fund Network Upgrades.[44] In those orders, the Commission acknowledged the risks that transmission owners face in owning and operating Network Upgrades and the need for them to earn a return on these facilities.[45] Specifically, the Commission found that "the rate of return available to transmission owners when they provide initial funding for network upgrades compensates them for business risk, such as lawsuits, reliability compliance obligations, and environmental and construction risks; in addition, it prevents transmission owners from operating a significant

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[40] *Id.*

[41] *Midcontinent Indep. Sys. Operator, Inc. & Otter Tail Power Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,158, P 32 (2018) ("*Ameren Remand Order*"), *reh'g denied*, 169 FERC ¶ 61,233 (2019).

[42] *See Ameren Remand Order*, 164 FERC ¶ 61,158 at P 28.

[43] *Id. See also* Order No. 845-B at P 26.

[44] *April 2020 MISO FSA Order*, 171 FERC ¶ 61,075 (approving a new *pro forma* Facilities Service Agreement, which provides a standard agreement for use when a transmission owner elects transmission owner initial funding option).

[45] *See April 2020 MISO FSA Order* at P 33.

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portion of their business on a non-profit basis and ensures that future capital can be attracted."[46] As the Commission explained in Order No. 845-B, "the adoption of participant funding, in and of itself, does not preclude the recovery of a return of and on, the costs of facilities" and "*Ameren* stands for the principle that the Commission cannot prohibit a transmission owner from earning a return of and return on, the cost of its [N]etwork [U]pgrades."[47]

III. THE EXISTING FUNDING MODEL IN PJM CONTRAVENES JUDICIAL AND COMMISSION PRECEDENT BECAUSE THE PJM TRANSMISSION OWNERS ASSUME THE RISKS OF OWNING AND OPERATING NETWORK UPGRADES WITH NO COMPENSATION FOR DOING SO.

A. The Existing Funding Model in PJM is Inconsistent with Judicial Precedent Because It Denies the PJM Transmission Owners Compensation for the Risks Associated with Owning and Operating Network Upgrades.

Under traditional cost-of-service ratemaking, regulated utilities invest capital to build transmission facilities on behalf of customers and assume the obligation to provide safe and reliable services to those customers at a reasonable cost. In return, utilities are provided an opportunity to recover their prudently incurred costs and to earn a reasonable return on their investment for their shareholders.[48] A key feature of this regulatory compact is the equitable balancing of the interests of the shareholders and ratepayers. The Supreme Court has held that to accomplish that balancing "[a] regulated industry is entitled to a return that is sufficient to ensure that new capital can be attracted and to sustain the financial integrity of the enterprise."[49] The Supreme Court also held that

> Rates which are not sufficient to yield a reasonable return on the value of the property used at the time it is being used to render the service are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.[50]

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[46] *Id*. at P 33.

[47] *See* Order No. 845-B at PP 27-28, 35; *see also* Order No. 845-A at P 20 (stating that "the Commission's Order No. 845 option to build revisions, which do not alter the Order No. 2003 crediting policy, do not conflict with the Ameren decision because they do not deprive transmission owners of the ability to earn a return on, and of, standalone network upgrade costs."

[48] *Hope* and *Bluefield*. *See also Jersey Cent. Power & Light Co. v. FERC*, 810 F.2d 1168, 1189 (D.C. Cir. 1987) (Starr, J., concurring) (stating that as part of the regulatory compact, ratepayers are provided universal service and protection against monopolistic profits, and utility investors receive "a level of stability in earnings and value less likely to be attained in the unregulated or moderately regulated sector")). *See also* Order No. 845-A at P 15 (explaining the regulatory compact as a construct "under which utilities construct facilities, have an obligation to serve, and receive a level of earnings in return).

[49] *Hope,* 320 U.S. at 603. Courts have repeatedly emphasized that "a utility's return must allow it to compete for funding in the financial markets." *See, e.g., Emera Maine v. FERC*, 854 F.3d 9, 20 (D.C. Cir. 2017).

[50] *Bluefield*, 262 US at 690.

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Importantly, the reasonable return must be on the all of the utility's assets and not just a portion of those assets. As stated in *Ameren* "[i]nvestors, however, invest in entire enterprises, not just portions thereof" and "it seems undisputable that when portions of a business are unprofitable, it detracts from the attractiveness to investors of the business as a whole –and that is a concern that the Commission must at least address under Hope's capital-attraction standard."[51]

As regulated entities operating under the cost-of-service model, the PJM Transmission Owners make capital investments to build their transmission facilities and provide safe and reliable transmission service to customers. In exchange, under the long-standing judicial precedents discussed above, the PJM Transmission Owners need to recover their prudently incurred costs and a reasonable return on their investments in their transmission systems. This recovery is necessary to ensure that they can attract new capital to support and sustain the financial integrity of their businesses. Under the traditional ratemaking model, a utility recovers its capital investment in its projects, the costs of owning and operating its facilities and a return on the transmission projects it develops.[52] The return is generally calculated by applying its regulated rate of return that is established by the Commission to the capital investment costs.[53] This is referred to as the utility's "rate base." The return on the utility's rate base (i.e., the equity component of the transmission owner's capital structure) is essentially the profit that the utility earns for constructing, owning, and operating its transmission assets and that profit is provided to shareholders to compensate them for their investment in the utility, as well as the risk that the utility may not recover all of the costs of owning and operating their transmission assets (including Network Upgrades).[54]

The Existing Funding Model deviates from the cost-of-service model in one crucial respect: the utility has no opportunity to earn a return on the capital costs associated with Network Upgrades.[55] Under the Existing Funding Model in PJM, the generator provides the upfront capital for the Network Upgrade and this capital is treated as a contribution that goes into the interconnecting utility's rate base at $0.[56] Once the Network Upgrade is constructed and placed into service, the utility is able to recover its operating and maintenance expenses from network transmission customers. However, because the Network Upgrades go into the utility's rate base at $0, the utility is unable to earn a return on those facilities.[57] In other words, while the interconnecting transmission owner recovers its operating and maintenance expenses, it does

[51] *Ameren* at 581.

[52] Hunger and Adamson Affidavit at 7.

[53] *Id*. at 5.

[54] *Id*. at 5-6.

[55] *Id.* at 9.

[56] *Id.*

[57] *Id*. at 5, 9 (noting under the Existing Funding Model, the PJM Transmission Owners are compelled to own and operate Network Upgrades on a "zero-return basis").

not earn a profit on those assets for its shareholders and worse is not compensated for the additional risk for owning and operating those assets.[58]

B. As *Ameren* Recognized, Transmission Owners Face Significant Risks for Owning and Operating Transmission Facilities and Thus, Must Be Compensated for Doing So.

As Messrs. Hunger and Adamson explain, businesses must be allowed to earn a profit and receive compensation for the assets they are owning operating, and maintaining.[59] One purpose of earning a profit for regulated businesses is to compensate regulated entities and their shareholders for the risk of otherwise unrecoverable expenses borne by shareholders.[60] Thus, the opportunity to earn a return on transmission facilities is critical to compensating transmission owners and shareholders for these risks.[61] As the *Ameren* court recognized, owning and operating transmission facilities, including Network Upgrades presents a number of risks for the transmission owner and the transmission owner should be compensated for such risks beyond recovering its costs.[62]

In his affidavit, Mr. Weaver discusses the uncompensated risks that the PJM Transmission Owners are forced to assume in connection with the installation, ownership, and operation of Network Upgrades. In particular, Mr. Weaver discusses (1) operational and safety risks; (2) reliability and cybersecurity compliance risks; (3) environmental risks; (4) weather and climate risks; and (5) outage coordination risks. Mr. Weaver states that regardless of whether the Network Upgrade is a greenfield transmission line or an upgrade or modification of an existing facility, the risks associated with owning and operating the Network Upgrades are similar.[63] In their affidavit, Messrs. Hunger and Adamson evaluate and discuss the financial risks imposed upon the PJM Transmission Owners under the Existing Funding Model and the impact of the growing uncompensated risks on investors. These risks are summarized below and are discussed in greater detail in the two affidavits accompanying this filing.

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[58] Hunger and Adamson Affidavit at 5 (noting that while the PJM Transmission Owners recover their O&M costs; recovering costs does not provide any profit for the business.). To the extent that any costs are passed through to retail customers through state-approved retail rates, those rates do not reflect the uncompensated risks associated with Network Upgrades.

[59] Hunger and Adamson Affidavit at 6-7.

[60] *Id.* The PJM Transmission Owners' retail rates do not reflect the risk of owning, maintaining, and operating Network Upgrades. Retail rates, which are approved by state regulatory commissions, are designed to recover the costs associated with the provision of local distribution service, not service over transmission facilities, such as Network Upgrades.

[61] *Id*. at 6 ("Without a return on the Network Upgrades, there is no mechanism to provide compensation for shareholders bearing these risks.").

[62] *Ameren* at 580.

[63] Weaver Affidavit at 6.

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- **Operational and Safety Risks**

In his affidavit, Mr. Weaver explains that Network Upgrades present operational and safety risks, which arise from the inherent safety hazards involved in the ownership and day-to-day operations of high voltage transmission facilities, and the increased complexities and risks of operating a transmission system when an element is on outage.[64] The core of each transmission owner's business model is to install, own, operate, and maintain its transmission facilities in accordance with Good Utility Practice; however, there are operational and safety risks in carrying out this obligation. These risks are most apparent when a transmission owner responds to an emergency related to facilities on its system.[65] In his affidavit, Mr. Weaver provides several examples of the types of emergency situations of which he is aware, such as damaged transformers or transformer fires at substations, and the operational and safety risks that they pose.[66] While all utilities' top priority is to prevent accidents from occurring, they do occur and safety accidents can result in lawsuits or regulatory penalties that may create costs that are not recoverable in rates.

- **Reliability and Cybersecurity Compliance Risks**

Network Upgrades create North American Electric Reliability Corporation ("NERC") compliance risks for transmission owners.[67] Mr. Weaver explains that transmission owners are required to comply with NERC Reliability Standards for every Bulk Electric System asset on its system, including Network Upgrades.[68] While transmission owners do their best to comply with NERC Reliability Standards, there is the risk of violations for which NERC can impose significant monetary penalties, which are not recoverable in rates.[69] Mr. Weaver also discusses how Network Upgrades present unique risks in this regard because interconnection customers can exercise the option to build under the PJM Tariff, which can increase the risks of noncompliance with reliability and cybersecurity standards because the transmission owner needs to transition such assets into its NERC compliance program after it assumes ownership of the facilities.[70]

- **Environmental Risks.**

Mr. Weaver further explains that installing, owning, and operating transmission assets, including Network Upgrades, presents environmental risks.[71] He explains that such activities can result in advertent discharge of contaminants of soil and/or water or damage to

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[64] Weaver Affidavit at 4, 7.

[65] *Id*. at 7.

[66] *Id*. at 8-11.

[67] *Id*. at 12.

[68] *Id*.

[69] *Id*. at 13-14.

[70] *Id*. at 14-15.

[71] *Id*. at 16-19.

environmentally-sensitive areas over which transmission systems may traverse. These discharges can require environmental remediation or regulatory penalties that are not always recoverable in transmission rates. As Messrs. Hunger and Adamson state these risks require compensation to protect shareholders.[72] Mr. Weaver states that here again, Network Upgrades present unique risks because interconnection customers may exercise the option to build and in doing so may choose sites that are more cost effective for interconnection but less desirable for long-term owning and operating of the assets. Mr. Weaver highlights a recent instance a PJM Transmission Owner has encountered this issue.[73]

- **Weather and Climate Risks**

According to Mr. Weaver, severe weather events represents one of the greatest threats to the reliability of the transmission system as they increase the risk of damage or destruction to a transmission owner's facilities, including Network Upgrades. This risk will only increase as the climate changes and severe weather events become more frequent, prolonged, and intense.[74] Mr. Weaver cites an example when Hurricane Isaias struck Exelon Corporation's Atlantic City Electric Company and Delmarva Power service territories in August 2020, there were over 50 transmission circuits ranging from 69 kV to 230 kV going out of service due to the storm.[75]

- **Outage Coordination Risks**

Mr. Weaver explains that to integrate a new generation resource into its system, a transmission owner must manage the project and coordinate outage scheduling of transmission facilities to allow for construction.[76] There are risks associated with outage coordination, which requires meticulous planning and coordination to ensure that the Network Upgrades are installed and energized without disrupting service. Mr. Weaver states that failure to coordinate outages can result in a number of problems, including delays in facility in-service dates, suboptimal transmission system configurations, and interference with other planned outages or other critical transmission projects. Each of these issues exposes the transmission owner to potential financial liability to third parties who might be subject to disruption or delay in service.

- **Financial Risks**

The growing number of Network Upgrades on the PJM Transmission Owners' systems operating without profit adversely impact the PJM Transmission Owners' business model and their ability to attract new capital. In their Affidavit, Messrs. Hunger and Adamson state that the Existing Funding Model compels the PJM Transmission Owners to operate a substantial, and quickly increasing, portion of their business on a non-profit basis. According to Messrs. Hunger and Adamson, in a market economy, no private business would choose to pursue such a business

[72] Hunger and Adamson Affidavit at 9.

[73] Weaver Affidavit at 18-19.

[74] *Id.* at 19.

[75] *Id.* at 19-20.

[76] *Id*. at 21.

model.[77] They explain that the PJM Transmission Owners are required to devote significant time and effort to own and operate Network Upgrades in the same manner as their other transmission facilities, but are forced to operate the Network Upgrades as non-profit segment of their business.[78] They state "[t]here is a fundamental unfairness about requiring private companies to operate a non-profit business; this is not something commonly observed in our economic system."[79]

Messrs. Hunger and Adamson explain that even though the PJM Transmission Owners recover their capital investment, they are still entitled to earn a profit or return on the Network Upgrades.[80] Capital investment is not the only resource that a transmission owner invests into a line of business, and that a transmission owner also invests in employee and management time, which have opportunity costs for the transmission owners.[81] They also explain that in a market economy, the potential for a profit is not linked to investment, and an example, they refer to a generation project developer who pays a number of contractors to provide services, such as the contractors who will design, build and operate the wires assets that connect the generators to the point of interconnection. These services are analogous to the services that the PJM Transmission Owners provide with respect to Network Upgrades, but these private contractors are not expected to undertake this work without any profit.[82] Requiring a utility to operate without a return or a profit for part of its assets is contrary to established regulatory principles, as set forth by the Supreme Court in *Hope* and *Bluefield*, holding that a utility must be allowed to earn a return that is sufficient to attract capital and that ensures the financial integrity of the utility.[83]

Messrs. Hunger and Adamson state that the requirement to operate a non-profit segment has the potential to impact the PJM Transmission Owner's financial integrity and ability to attract capital.[84] Specifically, they observe that in the past, the quantity of Network Upgrades not allowed to earn a return but operated by the transmission owner was relatively small. Thus, the risks imposed on the PJM Transmission Owners at that time was relatively little and did not to have a measurable impact on the transmission owner's ability to attract capital at a reasonable rate of return.[85] However, the quantity of Network Upgrades is expected to increase very significantly in the coming years.[86] Thus, the magnitude of assets that do not earn a return grows as a portion of total capital employed, and the utility becomes more thinly capitalized, affecting its ability to raise capital. According to Messrs. Hunger and Adamson, as the proportion of the

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[77] Hunger and Adamson Affidavit at 6.

[78] *Id.*

[79] *Id.* at 6.

[80] *Id*.

[81] *Id.*

[82] *Id.*

[83] *Hope*, 320 U.S. at 603. *See also Ameren* at 581.

[84] Hunger and Adamson Affidavit at 15-17.

[85] *Id*. at 15.

[86] *Id.* at 16.

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assets that are do not earn a return grows, the risks associated with operating expenses will grow, thereby imposing greater risks on utility shareholders. This will cause the transmission owner's cost of capital to increase, which will in turn adversely impact transmission customers.[87]

In their Affidavit, Messrs. Hunger and Adamson provides a simple example of the potential impact on a transmission owner's financial stability as a result of a large increase in Network Upgrades upon which it is not able to earn a return. Specifically, they compare the impact of a loss event upon two utilities (one that is able to earn a return on all of its transmission assets and a second utility that is able to earn a return only upon a portion of its transmission assets). In the event of a loss event, the two utilities are impacted very differently. In the example, shareholders of the first utility faces a reduced (but still positive) return while the shareholders of the second utility will face a negative return.[88] They observe that under the Existing Funding Model, because rate base assets will be "burdened with uncompensated risks associated with Network Upgrades," the investment community will reasonably expect these risks to be borne by shareholders and impacting the shareholders' return.[89]

C. The Significant Buildout of Network Upgrades Required to Accommodate the Transformation of the Energy Grid Increases the Risk to Transmission Owners and Further Diminishes the Compensation for Shareholders.

As noted above, the transformation of the energy grid and increase in renewable development has led to a significant increase in the number of generators seeking to interconnect to the PJM transmission system. The corresponding increase in Network Upgrades has changed the dynamics that were in place when PJM adopted the Existing Funding Model. PJM is currently reviewing its interconnection policies and processes as part of a larger stakeholder process.[90] The PJM Transmission Owners are participating in that process and support PJM's efforts to make the interconnection process more efficient and streamlined for Interconnection Customers. Further, the PJM Transmission Owners also support a re-examination of the decision to adopt the Existing Funding Model. However, in light of the sharp increase in the number of interconnection requests in PJM and the resulting increased risks imposed on the PJM Transmission Owners, it is imperative that the PJM Transmission Owners move forward now to make the proposed changes to the PJM Tariff. Nonetheless, the PJM Transmission Owners are open to considering any future changes that may be presented as a result of the outcome of the on-going stakeholder process.

As noted previously, the number of generator interconnection requests and the associated generation capacity have increased dramatically since 2004.[91] The PJM transmission system was

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[87] *Id*. at 17.

[88] *Id*. at 16.

[89] *Id.* at 17 (stating that "eventually increased risks will impact transmission rates as the cost of capital increases.").

[90] *See, e.g.,* PJM's presentation entitled "*Interconnection Process Reform Task Force Update*" at 14 (May 11, 2021); PJM's presentation by Craig Glazer, Vice President-Federal Government Policy PJM Interconnection entitled "*PJM Interconnection Workshop #1: An Overview of Federal Interconnection Policy* at 8 (Oct. 30, 2020).

[91] *See supra* at 5.

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simply not designed to accommodate all of the new generator interconnections. The transmission infrastructure required to accommodate the interconnection of 15,000 MW of generation capacity is significantly less than the infrastructure that will be required to accommodate the 147,000 MW of generation capacity associated with the 1,600 interconnection requests in the PJM queue as of December 2020. As noted above, if all of the current network upgrade projects in the PJM RTEP were to be completed, the result would be a transmission system that includes approximately $6.5 billion in Network Upgrades, including approximately $1.565 billion of Network Upgrades that are already built and in-service and approximately $4.9 billion of Network Upgrades associated with active projects in the queue.

For illustrative purposes, if we assume that 23 percent of the $4.9 billion (or $1.13 billion) of active Network Upgrades are ultimately constructed and placed in service (based upon the historical completion rates over the past three years), when this number is combined with the $1.565 billion of Network Upgrades built or under construction, the Network Upgrades for which the PJM Transmission Owners would not be entitled to earn a return in the next few years, would represent approximately four percent of the PJM Transmission Owners' current combined net transmission plant of $67 billion. This reflects a material and significant portion of transmission assets for the PJM Transmission Owners to own and operate with no compensation for the associated risks and a significant increase in the amount of Network Upgrades on the transmission system relative to when PJM adopted by the Existing Funding Model in 2004. And as demonstrated, this percentage will only increase as more Network Upgrades are added to the system to accommodate the continuing increase in generator interconnections largely due to the growth in renewable generation.

Moreover, Messrs. Hunger and Adamson explain that the historical completion rates for projects in the queue should not determine future estimates of the potential required interconnections of new generation resources because a major driver for new generator interconnection requests will be federal and state goals of decarbonizing the electric power industry, which will necessitate significant amounts of new renewable generation resources in the coming years.[92] Messrs. Hunger and Adamson state that to meet decarbonization targets, PJM will need to add additional renewable generation on a massive scale and that the associated Network Upgrades will be on the order of multiple billions of dollars.[93]

It is also important to recognize that the impacts of Network Upgrades on the transmission system are cumulative. Network Upgrades, like other transmission facilities, typically have useful lives of 40 to 50 years. Thus, the impact of owning and operating Network Upgrades without the opportunity to earn a return increases by the cumulative impact of those assets over their useful lives. The *Ameren* court noted the concerns with the cumulative impact of owning and operating a growing percentage of the transmission system with no return. As the court explained, "[T]he non-profit innovation might remain bearable so long as the generator-funded upgrades growing inside the grid remain tiny relative to their host. But if more and more of a transmission owner's business is to be owned and operated on a non-profit basis, these

[92] *Id.* at 14-15.

[93] *Id.* at 15.

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additions would likely deter investors and diminish the ability of the transmission grid to attract capital for future maintenance and expansion."[94] The PJM transmission system has hit its tipping point: the risks that the PJM Transmission Owners are being asked to assume without compensation will deter investors and diminish the PJM Transmission Owners' ability to attract capital for future maintenance and expansion.[95]

The impact on individual PJM Transmission Owners is also telling. For example, the approximately $6.5 billion of Network Upgrades represents: $1.841 billion on the ComEd transmission system; $1.643 billion on the AEP transmission system; $649 million on the Dominion transmission system; $415 million on the PPL transmission system; and $584 million on the PSE&G transmission system. For illustrative purposes, if all of ComEd's $1.841 billion of Network Upgrades are built and placed in service, this would represent 48 percent of ComEd's current transmission rate base.[96] Indeed, even if a fraction of the $1.841 billion of Network Upgrades on ComEd's system are ultimately built, it would still represent a significant portion of ComEd's transmission rate base.

The growing percentages of Network Upgrades as a proportion of the transmission system will increase the risk burden upon shareholders. As Messrs. Adamson and Hunger explain, as the number of Network Upgrades increases, the financial risk will increase; the proportion of rate base assets upon which a PJM Transmission Owner earns a return to total transmission assets will fall, which will "amplify risks for shareholders, who will face larger potential losses on a smaller proportion of rate base assets.[97] As the *Ameren* court recognized, the compulsory generator funding model is not sustainable especially if an increasing portion of the transmission owner's business is forced to operate on a non-profit basis.

To remedy this deficiency, the PJM Transmission Owners are proposing tariff revisions to provide them with the option to elect to provide funding for the capital costs of Network Upgrades. The Proposed Revisions are just and reasonable because they provide the PJM Transmission Owners with the opportunity to earn a return on Network Upgrades consistent with Supreme Court precedent and *Ameren*. This opportunity to earn a return will appropriately

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[94] *Ameren* at 582. Indeed, the court expressed alarm during oral arguments when counsel for the Commission responded to a hypothetical "that if a group of generators got together to fund a billion-dollar upgrade that totally refurbished a portion of the grid, the transmission owner would be obliged to operate and assume liability for the upgrade – with operations and maintenance costs reimbursed, but no return. The answer, alarmingly, was yes." *Id.* at 582 (citations omitted).

[95] *See also* Hunger and Adamson Affidavit at 4, 21 (stating that the Current Funding Model could "impact their ability to raise capital on reasonable returns.").

[96] ComEd's current transmission rate base is $3.844 billion. The $1.841 billion of Network Upgrades for ComEd is comprised of the following cost categories: (1) $307 million (in-service); (2) $1.449 billion (active); (3) $47.6 million (in the engineering/procurement phase); and (4) $35.9 million (under construction). Not all of the $1.449 billion of Network Upgrade Costs in the active category will be constructed as some generation projects may drop out of the queue for various reasons.

[97] Hunger and Adamson Affidavit at 21.

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compensate the PJM Transmission Owners and their investors for owning and operating Network Upgrades.[98]

IV. THE PROPOSED REVISIONS ARE JUST AND REASONABLE AND ESTABLISH A MECHANISM TO COMPENSATE THE PJM TRANSMISSION OWNERS FOR OWNING AND OPERATING NETWORK UPGRADES.

The Proposed Revisions establish a process for the PJM Transmission Owners to exercise an option to fund Network Upgrades and create a *pro forma* agreement to implement that option. The option to fund Network Upgrades (and therefore earn a return on those facilities) addresses the issues with the Existing Funding Model discussed above. Allowing the PJM Transmission Owners the option to elect to fund Network Upgrades provides them with the opportunity to be compensated for the risks of owning and operating those facilities.

The Proposed Revisions include:

(i) a new Section 217.8 to PJM Tariff, Part VI that sets forth a just and reasonable process governing how and when a transmission owner could elect to fund Network Upgrades; and
(ii) a *pro forma* Network Upgrade Funding Agreement ("NUFA"), proposed to be incorporated into the PJM Tariff as new Attachment O-2 that provides standard terms and conditions for the recovery of the return of and on the capital.

These two components are largely based on the process and *pro forma* agreement approved by the Commission for the MISO Transmission Owners.[99]

A. The PJM Transmission Owners Have the Unilateral Right Under the CTOA and Section 9 of the PJM Tariff, Part I to Make the Proposed Changes.

Under Section 9.1 of PJM Tariff, Part I, the PJM Transmission Owners, acting pursuant to the CTOA, have the right to make a Section 205 filing to change PJM Tariff provisions affecting their revenue requirement recovery or rate design. [100] Specifically, Section 9.1(a) of PJM Tariff, Part I provides the PJM Transmission Owners with the "the exclusive and unilateral rights to file pursuant to Section 205 of the Federal Power Act and the [Commission's] rules and regulations thereunder for any changes in or relating to the establishment and recovery of the Transmission Owners' transmission revenue requirements or the transmission rate design under

[98] *See also* Hunger and Adamson Affidavit at 18 ("charging an approved return on rate base is used to compensate for the risks associated with deploying capital to provide transmission service and the inherent risks associated with operating a transmission business.")

[99] *Ameren Remand Order*, 164 FERC ¶ 61,158 (2018); *Midcontinent Indep. Sys. Operator, Inc*., 169 FERC ¶ 61,233 (2019); *Midcontinent Indep. Sys. Operator, Inc*., 172 FERC ¶ 61,248 (2020); *April 2020 MISO FSA Order*, 171 FERC ¶ 61,075 (2020), *order on reh'g*, 173 FERC ¶ 61,037 (2020).

[100] *See also* CTOA, Section 7.7.1 (stating that "Each party shall have the exclusive right to file unilaterally at any time pursuant to Section 205 of the Federal Power Act to establish or change the transmission revenue requirement for services provided under the PJM Tariff with respect to its Transmission Facilities").

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the PJM Tariff."[101] As discussed above, the Existing Funding Model in PJM requires a Transmission Owner to place Network Upgrades into rate base at $0. Thus, the Transmission Owner cannot collect a full revenue requirement for the Network Upgrades or receive compensation for the risks of owning and operating those facilities described above. The Proposed Revisions provide the option for earning a return on those Network Upgrades and therefore fall within the PJM Transmission Owners' unilateral filing rights as defined by Section 9.1 of the PJM Tariff, Part I.

In accordance with Sections 7.12.1 and 8.15.1 of the CTOA, the PJM Transmission Owners have authorized this Section 205 filing, pursuant to a vote of the TOA-Administrative Committee ("TOA-AC").[102] On April 16, 2021, pursuant to Section 9.1(b) of PJM Tariff, Part I the PJM Transmission Owners initiated consultation with PJM and the PJM Members Committee by providing notice of the modifications proposed in this filing together with a draft of those modifications. That notice requested the submission of written comments by May 17, 2021. A copy of the power point presentation used during the webinar is attached as Exhibit F. The PJM Transmission Owners held an open webinar for PJM Members on April 27, 2021 during which they answered questions and addressed issues raised by the PJM Members. Based on the input and feedback provided by stakeholders, including PJM, the PJM Transmission Owners revised certain aspects of their proposal, including the Security provisions, as explained further below. The Proposed Revisions were initially authorized pursuant to the individual and weighted voting requirements in Section 8.5 on June 9, 2021. However, subsequent to that vote, the PJM Transmission Owners made additional changes in response to further comments from PJM on the implementation of the Proposed Revisions. On June 25, 2021, the PJM Transmission Owners, pursuant to a vote of the TOA-AC, voted in support of certain implementation revisions in response to PJM's suggestions.

B. Proposed Section 217.8 of PJM Tariff, Part VI Provides a Just and Reasonable Process to Implement the Option for Transmission Owners to Fund Network Upgrades.

The PJM Transmission Owners propose a new section in the PJM Tariff, Part VI, Section 217.8 to govern how and when a transmission owner can elect to fund Network Upgrades.[103] Proposed Section 217.8 is consistent with the process that the Commission approved for the MISO Transmission Owners. The provisions of proposed Section 217.8 are summarized below:

[101] PJM Tariff, Part I, Section 9.1(a).

[102] *See* CTOA, sections 7.12.1, 8.15.1. The PJM Transmission Owners have made similar filings in the past to address changes to the costs that are recovered from New Service customers related to accelerating projects in the PJM RTEP process. *See PJM Transmission Owners*, 125 FERC ¶ 61,021 (2008) (accepting PJM Transmission Owners' proposed changes to Section 217.3 of the PJM Tariff to identify the costs that would be charged to interconnection customers when their request requires the acceleration of an RTEP project.)

[103] The PJM Transmission Owner's initial funding proposal for network upgrades applies to both small generator interconnection requests (i.e., 20 MW or less) and large generation interconnection requests (*i.e.*, greater than 20 MW).

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- Section 217.8(a) provides the Interconnected Transmission Owner with the right to elect to fund the capital cost of Network Upgrades, including where the Interconnection Customer has exercised the Option to Build.[104] If the Interconnected Transmission Owner elects to fund Network Upgrades, the Interconnected Transmission Owner must provide written notice to PJM and the Interconnection Customer, and the parties will enter into a NUFA memorializing the terms of repayment. Either the Interconnection Customer or the Interconnected Transmission Owner may request PJM to file the NUFA with the Commission on an unexecuted basis.

- Section 217.8(b) includes a definition of Interconnected Transmission Owners and clarifies that the Interconnected Transmission Owner can include transmission owners whose facilities must be upgraded but whose facilities are not directly interconnected to the Interconnection Customer.

- To provide Interconnection Customers with notice regarding each Interconnected Transmission Owner's intent, Section 217.8 (c) of the Proposed Revisions provides that PJM will maintain on the PJM website each Interconnected Transmission Owner's general non-binding indication as to whether the Interconnected Transmission Owner intends to elect to fund Network Upgrades.[105] PJM will also maintain a list of the projects for which an Interconnected Transmission Owner has elected to fund the Network Upgrades on PJM's public website. This will provide Interconnection Customers with transparency and an advanced indication of each individual Interconnected Transmission Owner's intent in order to facilitate informed decision-making.

- Each Interconnected Transmission Owner will indicate whether it intends to fund each specific Network Upgrade prior to the completion of the Facilities Study, and the Interconnected Transmission Owner's funding election will be included in the Facility Study Report. If the Interconnected Transmission Owner has elected to fund the Network Upgrades, PJM will provide the Interconnection Customer with a NUFA at the same time that it provides the Interconnection Construction Service Agreement ("ICSA"). Unless otherwise specified in the Interconnection

[104] The PJM Transmission Owners are not proposing to change the Option to Build under the PJM Tariff in any way. In Order No. 845-A, the Commission emphasized: "Order No. 845 does not deprive transmission providers of the ability to earn a return of and on, network upgrades, including standalone network upgrades constructed pursuant to the option to build as outlined in the pro forma LGIA." Order No. 845-A at P 19; *see also* Order No. 845-B at PP 27-28 ("Order No. 845 did not change the fact that the Commission explicitly provided an option pursuant to which transmission providers can earn a return of, and on, the network upgrades through the Order No. 2003 crediting policy" and "that the adoption of participant funding, in and of itself, does not preclude the recovery of a return of, and on, the costs of facilities.").

[105] The PJM Transmission Owners' proposal to maintain on the PJM website a non-binding indication of each PJM Transmission Owner's intention to elect to fund Network Upgrades is similar to the proposal that the Commission approved for the MISO Transmission Owners. *See Midcontinent Independent System Operator, Inc.*, ER20-2632, Letter Order (Oct. 1, 2020) approving MISO's August 7, 2020 filing of revisions to MISO's generator interconnection procedures.

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Service Agreement ("ISA"), the Interconnection Customer must execute the NUFA and it must be in the possession of PJM and the Interconnected Transmission Owner concurrently with the ICSA. Alternatively, the Interconnection Customer will request dispute resolution under the PJM Tariff or that the NUFA be filed unexecuted with the Commission. Pending the resolution of the dispute, construction of the facilities and Network Upgrades identified in the NUFA will be deferred. Section 217.8(c) also describes the process by which the Interconnected Transmission Owner will review and execute the NUFA. Consistent with the process for the Interconnection Customer, the Interconnected Transmission Owner can also request dispute resolution under the PJM Tariff or that the NUFA be filed unexecuted with the Commission.

- Proposed Section 217.8(d) states that a breach by the Interconnection Customer of any terms or conditions under the NUFA shall be considered a breach of the ISA. This is consistent with the cross-default provisions approved by the Commission for the MISO Transmission Owners.[106]

- Proposed Section 217.8(e) addresses the Interconnected Transmission Owner's reimbursement obligation if the Interconnection Customer exercises the Option to Build under the ICSA and the Interconnected Transmission Owner has elected to fund the Network Upgrade. Prior to the Interconnection Customer incurring any construction costs, PJM will invoice the Interconnected Transmission Owner on behalf of the Interconnection Customer for the estimated amount to be expensed to construct any Network Upgrades, and the Transmission Owner will make payment to PJM within twenty (20) days of receipt of the invoice.

- Proposed Section 217.8(f) provides that as a transition to the PJM Transmission Owners' funding proposal, for any Customer Facility for which the Interconnection Customer has not executed a Facilities Study Agreement on or before October 1, 2021, the Interconnected Transmission Owner will have the right to elect to fund the Network Upgrades.

- Proposed Section 217.8(g) clarifies that the Proposed Revisions are not intended to alter or affect in any way the rights of which an Interconnection Customer is entitled under Part VI, Subpart C of the PJM Tariff, except to the extent the applicable terms of Subpart C provide otherwise.

[106] This proposed provision is similar to the cross-default provision that the Commission approved for the MISO Transmission Owners. *See April 2020 MISO FSA Order* at PP 65, 70 (finding MISO's breach, default, and cross-default provisions are just and reasonable and the "cross-default provisions appropriately protect transmission owners from strategic non-payment of the FSA").

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C. The Proposed *Pro Forma* NUFA Provides a Just and Reasonable Mechanism to Recover the Return of and on the Capital for Network Upgrades.

The *pro forma* NUFA provides standard terms and conditions for recovering the return of and on the capital investment in connection with a PJM Transmission Owner's election to provide funding for Network Upgrades. The *pro forma* NUFA is largely modeled on the Facility Service Agreement ("FSA") approved by the Commission to govern transmission owner funding of Network Upgrades in MISO.[107] The NUFA includes a formula rate similar to the formula used in the MISO agreement that uses inputs based on the Network Upgrades and information from each transmission owner's formula rate to determine a periodic payment amount, as discussed further below.

As the administrator of the PJM Tariff and pursuant to the terms of the CTOA, PJM is responsible for administering the agreements under the PJM Tariff and for billing and collecting payments for the PJM Transmission Owners related to interconnections to their transmission facilities in the PJM region. Thus, the PJM Transmission Owners propose deviations from the MISO *pro forma* agreement to reflect PJM's role under the NUFA. Specifically, the PJM Transmission Owners propose that PJM will be responsible for administering the agreement, billing, and collecting payments, similar to PJM's current role and responsibilities under the *pro forma* ISA and ISCA.[108] Under the *pro forma* NUFA, the interconnection customer will have the option to select either PJM or the PJM Transmission Owner to hold the security for the Network Upgrade.

The provisions in the proposed *pro forma* NUFA are summarized below:

1. Definitions

Section 1 states that capitalized terms used in the NUFA that are not otherwise defined will have the meaning provided under the PJM Tariff.[109]

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[107] *See April 2020 MISO FSA Order*.

[108] CTOA, section 6.3.6 broadly states that among PJM's responsibilities under the CTOA is that PJM shall "[c]ollect and pay to each Party all amounts due to such Party as a Transmission Owner under the PJM Tariff and to distribute such amounts in accordance with the PJM Tariff and this Agreement."

[109] Schedule A to the NUFA identifies the specific Network Upgrade(s) that the Interconnected Transmission Owner has elected the self-fund option.

2. Section 2 – Effective Date and Term

Consistent with the FSA adopted in MISO, Section 2 of the NUFA establishes the default term of the NUFA to be 20 years unless otherwise agreed to by the Parties. As the Commission found in accepting the MISO FSA, a twenty year term "is reasonable because it allows the transmission owner to recover its return on and of capital invested in Network Upgrades over a time period based on the term over which interconnection service will be provided, while providing the interconnection customer with a shorter period to pay depreciation expenses than the period of recovery based on useful service life generally used in Commission ratemaking."[110]

3. Section 3 – Network Upgrade Charge

The Interconnected Transmission Owners will recover compensation for the return of and on the costs of the Network Upgrades through a Network Upgrade Charge. The Network Upgrade Charge is modeled on the Network Upgrade charge approved by the Commission for recovery of the costs of Network Upgrades in MISO.[111] Section 3 of the *pro forma* NUFA addresses how the Network Upgrade charge will be established and billed to the Interconnection Customer.

Under the terms of the NUFA, the Network Upgrade Charge will begin in the month following the Network Upgrade being placed into service and will continue for the term of the NUFA.[112] The Network Upgrade Charge is calculated through a formula included in the form of Schedule B to the NUFA. The formula rate multiplies the capital invested in the Network Upgrade by a levelized fixed charge rate determined from the terms of the NUFA and data from the Interconnected Transmission Owner's formula rate, including taxes, interest on long-term debt, and return on equity ("ROE").[113] The Network Upgrade Charge does not include operation and maintenance expense, general and common depreciation expenses, and taxes other than income taxes.[114] This is consistent with the formula rate template approved by the Commission

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[110] *April 2020 MISO FSA Order* at P 61.

[111] *Id.* at P 49.

[112] *See pro forma* NUFA § 2.

[113] Consistent with the agreement approved by the Commission in MISO, the PJM Transmission Owners plan to use their respective ROEs from their Formula Rates contained in Attachment H of the PJM Tariff.

[114] Consistent with the MISO formula rate that the Commission approved, the PJM Transmission Owners plan to depreciate the Network Upgrades using the MACRS depreciation for tax purposes and straight-line depreciation over the term of the NUFA for ratemaking purposes. *April 2020 MISO FSA Order* at P 54. The PJM Transmission Owners also account for the effect of ADIT using the "present net worth tax benefit" as a proxy for ADIT. Consistent with the MISO formula rate, present net worth tax benefit is deducted from the initial capital investment made by the transmission owner, resulting in an overall reduced Network Upgrade charge. The reduced initial capital investment amount is then grossed-up by the applicable combined tax rate to derive a present worth revenue requirement. The proposed Network Upgrade charge formula then converts the present worth revenue requirement into a levelized monthly charge over the twenty-year period that the Network Upgrade Charge is recovered under the NUFA. By virtue of the above noted tax benefit deduction, the Network Upgrade Charge fully accounts for the benefits of the timing difference between when the network upgrades are depreciated for tax purposes and when the costs of the Network Upgrades are recovered over the 20-year term of the NUFA. *April 2020 MISO FSA Order* at P 56.

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in MISO.[115] To illustrate the calculation of the Network Upgrade Charge, the PJM Transmission Owners include an example of a populated formula rate template to the NUFA in Excel format (*see* Attachment E).[116]

Section 3.1 of the NUFA states that PJM will invoice the Interconnection Customer on behalf of the Interconnected Transmission Owner for the amount of the monthly revenue requirement for the Network Upgrade. Upon receipt of each Interconnection Customer's payments, PJM will remit payment to the Interconnected Transmission Owner. The initial payment will be based upon the Estimated Network Upgrade Initial Capital Cost ("ENUC") and the levelized fixed charge rate, as set forth in the chart in Section 3.3 and further detailed in Schedule B to the NUFA. Consistent with the formula rate approved in MISO, the estimated cost of the Network Upgrade will be trued-up based on the actual costs of the Network Upgrade.[117]

The Network Upgrade Charge will also be re-calculated annually using updated inputs from each Interconnected Transmission Owner's PJM Tariff, Attachment H Formula Rate.[118] To enhance transparency, the PJM Transmission Owners will also include a populated Schedule B template as a workpaper in each Transmission Owner's Annual Update filing. This will allow customers to calculate their own estimates of the applicable charges under the NUFA. The NUFA also requires recalculation of the Network Upgrade Charge each year to reflect any adjustments to the inputs from the Transmission Owner's Formula Rate in Attachment H and requires refunds or surcharges as necessary. An almost identical formula rate (as the one set forth in Schedule B to the NUFA) and the process proposed for updating the Formula Rate were approved by the Commission for MISO.[119] Section 3.5 provides for the sharing of information by the Interconnected Transmission Owner and the Interconnection Customer to the other parties necessary for cost verification purposes.

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[115] *April 2020 MISO FSA Order* at P 50.

[116] The example of a populated formula rate template in Attachment E is based upon the following assumptions: (1) Capital Cost of Network Upgrade: $1 million; (2) Term: 20 years; (3) ROE: 10.35%; (4) Capital Structure: 50% debt/50% equity; (5) Cost of Debt: 4%; (6) Tax Rate: Federal – 21%; State – 9%.

Messrs. Hunger and Adamson note that the Commission-jurisdictional transmission owners, such as the PJM Transmission Owners, generally have a low weighted average cost of capital ("WACC") due to their business model than generation developers and this should serve to mitigate concerns regarding increased interconnection costs associated with the PJM Transmission Owners' Network Upgrade funding proposal. *Id.* at 19.

[117] *Id.* at P 51.

[118] Consistent with MISO, the calculation will be performed with actual costs to determine the Network Upgrade Charge. Thus, if the PJM Transmission Owner's formula rate is based on forward-looking projections, the transmission owner will use its true-up data to determine the Network Upgrade Charge because the true-up data is verifiable data. If the PJM Transmission Owner's formula rate is based on historical data, it will use its prior year historical actual data to update the Network Upgrade Charge. *Id.* at P 52.

[119] *April 2020 MISO FSA Order* at P 61. The PJM Transmission Owners made minor adjustments to the formula rate to provide more clarity on how the inputs track to their individual formula rates and provide more transparency to customers. Unlike the transmission owners in MISO, the PJM Transmission Owners do not have a standard formula rate template.

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4. Section 4 -- Security

The Interconnection Customer will have the option to provide Security to either PJM or the Interconnected Transmission Owner and will notify all parties of its election within ten days of receipt of the NUFA from PJM. Section 4 of the NUFA further states that the Interconnection Customer will provide a letter of credit from a reasonably acceptable provider or other form of reasonably acceptable security that names either PJM (for the benefit of the Interconnected Transmission Owner) or the Interconnected Transmission Owner as the beneficiary in an amount equal to the ENUC (the "Security"). The PJM Transmission Owners propose to allow the Interconnection Customer to choose either PJM or the Interconnected Transmission Owner to hold the security for two reasons. First, this will reduce the potential burden on PJM because it will not have to hold the security in all cases. Second, it will allow the customer to choose PJM to hold the security if the interconnection customer believes that is in it is best interest to do so.

Security will be provided by the Interconnection Customer to PJM or the Interconnected Transmission Owner, as applicable, within the timeframe set forth in Section 4. Section 4.1 also clarifies that if the Interconnection Customer provides Security for the Network Upgrade under the ISA, the customer will not need to provide Security for the same Network Upgrade under the NUFA while the Security is held under the ISA. In other words, the Interconnection Customer will not be required to maintain concurrently the full amount of the Security under the ISA and the full amount of Security under the NUFA.[120] However, prior to release of the Security under the ISA for the Network Upgrade by the Interconnected Transmission Provider, the Interconnection Customer must increase the Security held under the NUFA by a corresponding amount. Section 4.1 provides that the Interconnection Customer will not allow the Security to lapse between the ISA and the NUFA. Importantly, as the terms indicate, there will be no duplication of the security provided under the ISA and NUFA.

The Security is a critical component of the NUFA as it ensures that the Interconnected Transmission Owner will not be left to own and operate the Network Upgrade specifically required for the interconnection of the Interconnection Customer's generating facility without compensation and putting the Interconnected Transmission Owner, transmission customers, and other interconnection customers at risk for the unrecovered costs. As the Commission found in approving similar security provisions in the MISO FSA, the security "is reasonable to protect the transmission owner and transmission service customers from the risk that an interconnection customer will stop making payments under an FSA and that the portion of the undepreciated costs would be borne by either the transmission owner or transmission service customers, or assigned to another interconnection customer."[121] The same reasoning is equally applicable to the security provisions in the NUFA.

5. Section 5 – Breach, Default and Cross-Default.

Section 5 sets forth provisions relating to breach, default and cross-default. Section 5.2 and Section 5.3 set forth the circumstances under which the Interconnection Customer and the

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[120] *See April 2020 MISO FSA Order* at P 32 (approving the MISO transmission owners' proposed security)

[121] *Id*. at P 32.

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Interconnected Transmission Owner will be in default of the NUFA, respectively. If a breach occurs, the breaching party will have thirty days to cure the breach or ninety days to cure the breach if the breach cannot be cured within thirty days. Section 5.4 of the *pro forma* NUFA states a breach by the Interconnection Customer of any provision of the NUFA shall be deemed a breach under the ISA. If a default under the ISA results from the Interconnection Customer's breach of the NUFA, PJM and the Interconnected Transmission Owner will be entitled but not required to apply all of the rights and remedies available by reason of default under the NUFA and the ISA. The Commission accepted a similar provision in the MISO FSA, finding that the cross-default provisions "appropriately protect transmission owners from strategic non-payment of the FSA. Without such provisions, an interconnection customer could decide not to pay under the FSA (and not maintain the required security) and still receive interconnection service using the unpaid [N]etwork [U]pgrades."[122]

6. Section 6 – Reimbursed Network Upgrades

Section 6 addresses the scenario in which PJM determines that some or all of the costs for a Network Upgrade covered by the NUFA should be allocated to another Interconnection Customer. If this occurs, the parties to the NUFA will amend the NUFA or enter into a new agreement to reflect the initial Interconnection Customer's and new Interconnection Customer's allocated responsibility for the costs of the Network Upgrade.[123]

7. Section 7 – Assignment

Section 7 provides that no party will assign the agreement or their related contractual rights without the prior written consent of the other parties, which prior written consents shall not be unreasonably withheld for delay, subject to condition that the assignee is at least as creditworthy as the assigning party and the assignee of the Interconnection Customer will provide the security as contemplated under the NUFA.

8. Section 8 – No Transmission Service

Section 8 provides that the execution of the NUFA does not constitute a request, or entitle the Interconnection Customer, to receive transmission service under the PJM Tariff, nor does it obligate the Interconnected Transmission Owner or the Transmission Provider to procure, supply or deliver to the Interconnection Customer any energy, capacity, ancillary services or station power or any associated distribution services.

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[122] *Id.* at P 70.

[123] MISO's FSA contains a provision titled "Additional Upgrades." *See* MISO's *pro forma* FSA, Article VII. This provision is not applicable in PJM and therefore is not included in the *pro forma* NUFA.

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9. Section 9 – Other

Section 9 of the *pro forma* NUFA sets forth standard commercial terms and conditions, such as provisions relating to the preservation of confidential information and competitively sensitive information, regulatory approval, force majeure, dispute resolution, and the parties' reservation of rights under Section 205 and 206 of the FPA.

D. The PJM Transmission Owners Propose a Transparent Selection Process to Address Concerns of Affiliate Abuse.

The Proposed Changes are consistent, and in many instances identical to the proposed changes that the Commission accepted to facilitate transmission owner funding of network upgrades in MISO. The PJM Transmission Owners are similarly situated to the transmission owners in MISO, and the Commission should approve the Proposed Revisions, which are consistent with the tariff provisions that the Commission approved in MISO. While concerns have been raised that the MISO's rules on Network Upgrades can create the potential for discrimination or affiliate abuse,[124] the proposed changes were approved by the Commission in MISO and remain part of the MISO Tariff. In addition, to date, the PJM Transmission Owners are not aware that there has been a Section 206 complaint filed alleging affiliate abuse in MISO with respect to the implementation of transmission owner funding of Network Upgrades. Similar concerns of affiliate abuse within in PJM do not exist as many PJM Transmission Owners have already divested their generation assets. As discussed below, PJM's extensive involvement with the interconnection process, and proposed role under the *pro forma* NUFA will mitigate affiliate abuse concerns. Further, the PJM Transmission Owners also propose a transparent process to govern the option to fund Network Upgrades to further mitigate any affiliate concerns.

First, PJM continues to provide a level of protection against affiliate concerns through the interconnection process. PJM administers the interconnection of new generation resources, coordinates the planning process for the interconnection of new generation, and analyzes the reliability impact of the proposed generating projects, including conducting the feasibility study, system impact study, and interconnection facilities study. PJM is also a party to the ISA and ICSA, three-party agreements that are executed among the Interconnection Customer, the transmission owner, and PJM. Under the PJM Transmission Owners' funding proposal, PJM would also be involved in administering the NUFA. In short, PJM's involvement in the interconnection process mitigates concerns of affiliate abuse in the interconnection process and will do the same for the Transmission Owner funding of Network Upgrades.

Second, to the extent that there is any residual affiliate concern, the PJM Transmission Owners also propose certain measures to mitigate such concern and provide further transparency regarding their choice to fund Network Upgrades. Specifically, the PJM Transmission Owners propose to provide a non-binding statement of general intent on the PJM website of how each Transmission Owner plans to treat Network Upgrades on its system. Moreover, as set forth in

[124] *See, e.g.*, *Midcontinent Independent System Operator, Inc.*, 174 FERC ¶ 61,084 (2021), concurring statements of Chairman Glick and Commissioner Clements.

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Proposed Section 217.8(c), each PJM Transmission Owner will provide its binding intent to fund each specific Network Upgrade prior to the completion of the Facilities Study.[125] This will provide a general indication to all generators seeking to interconnect in the transmission owner's zone whether the PJM Transmission Owner is likely to elect to fund the Network Upgrades for their project. Finally, each PJM Transmission Owner will arrange to post on the PJM website a list of the Network Upgrades it elects to fund with an accompanying statement of whether the Interconnection Customer is an affiliate as an added measure of transparency.

E. The Proposed Revisions are Just and Reasonable and Consistent with or Superior to the Requirements of Order No. 2003

As previously explained, the Existing Funding Model does not provide a return for Network Upgrades or fairly compensate the PJM Transmission Owners for the risks of uncompensated costs associated with owning and operating them. As recognized in *Ameren*, there are inherent risks associated with owning and operating transmission facilities, and requiring transmission owners to own and operate those facilities without any return creates substantial financial risk for transmission owners because it undermines investor confidence. The Supreme Court made clear in *Hope* that rates established by the Commission must balance the interests of investors and consumers.[126] In doing so, the Commission must also ensure that the established rates "fairly compensate investors for the risks that they have assumed."[127] The Proposed Revisions provide an option for the PJM Transmission Owners to earn a return on Network Upgrades, thus properly compensating them for the risks associated with owning and operating those facilities consistent with the manner in which they are compensated for owning and operating other transmission facilities on their systems. The Commission recently reaffirmed the need to compensate transmission owners for owning and operating Network Upgrades in MISO. Because the PJM Transmission Owners are similarly situated to the transmission owners in MISO, and the Proposed Revisions mirror those the Commission approved for the MISO transmission owners, the Commission should approve the Proposed Revisions, as requested by the PJM Transmission Owners.

The PJM Transmission Owners' proposal is also consistent with or superior to the requirements of Order No. 2003, which establishes a crediting mechanism that "explicitly allows" transmission owners to earn a return of and on, the costs of Network Upgrades.[128] However, as discussed above, PJM's Order No. 2003 compliance filing retained its pre-Order No. 2003 generator funding approach because it provided appropriate price signals to generators

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[125] This is similar to the proposal that the Commission approved for the MISO Transmission Owners. *See Midcontinent Independent System Operator, Inc*., ER20-2632, Letter Order (Oct. 1, 2020) (approving revisions to Attachment X of the MISO Tariff providing for the transmission owner to provide a non-binding statement regarding its general intent to fund Network Upgrades on its system and to implement a deadline for transmission owners to exercise the option to provide funding for Network Upgrades)

[126] *Hope*, 320 U.S. at 603.

[127] *In re Permian Basin Area Rate Cases*, 390 U.S. 747, 792 (1968).

[128] *See* Order No. 2003 at P 657; Order No. 845-A at P 19.

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to ensure efficient use of the bulk power system in the PJM Region.[129] However, in the ensuing years since the adoption of that approach, the number of generator interconnections have substantially increased and the amount of active Network Upgrades associated with those generator interconnection creates increasing risks for the PJM Transmission Owners. Thus, the Existing Funding Model is no longer sustainable for the PJM Transmission Owners. The Proposed Revisions provide the PJM Transmission Owners the opportunity to earn a reasonable return on the Network Upgrades consistent with the Commission's *pro forma* crediting approach adopted in Order No. 2003. The proposed changes also bring the Existing Funding Model in PJM in compliance with existing court precedent,[130] and addresses the issues raised in *Ameren*.[131]

Accordingly, the PJM Transmission Owners ask the Commission to find that the Proposed Revisions comply with the requirements of Order No. 2003, as well as judicial precedent and recent Commission orders in MISO, and approve the PJM Transmission Owners' proposal to establish an option to fund Network Upgrades and earn a return as it did for the MISO Transmission Owners.[132] To the extent necessary, the Commission should also find that the Proposed Revisions are "consistent with or superior to" Order No. 2003. In sum, the PJM Transmission Owners respectfully request that the Commission find the Proposed Revisions are just and reasonable, and not unduly discriminatory or preferential and approve them without hearing, modification or condition.

V. PROPOSED EFFECTIVE DATE AND WAIVER REQUEST

The PJM Transmission Owners request that the Commission issue an order accepting this filing within sixty-one days from the date of the filing or August 30, 2021. The PJM Transmission Owners request the Commission to grant any and all waivers of its rules and regulations as necessary for the Commission to accept the proposed tariff revisions to the PJM Tariff for filing. Cost support associated with the costs of exercising the PJM Transmission Owners funding proposal would be submitted in connection with any NUFA. The PJM Transmission Owners request a waiver of any applicable requirement of Part 35 for which a waiver is not specifically requested, if necessary, in order to permit this filing to become effective as proposed.

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[129] PJM 2004 Answer at 5.

[130] *See, e.g., Hope* and *Bluefield* (Supreme Court precedent holding that a regulated industry is entitled to a return that is sufficient to ensure that new capital can be attracted).

[131] *Ameren* at 582. (noting that the responsibility for owning and operating additional network upgrades without the opportunity to earn a return would likely deter investors and diminish the transmission owners' ability to attract capital for future maintenance and expansion).

[132] Courts have held that it is unduly discriminatory and unlawful for the Commission to treat similarly situated parties differently. *See, e.g.*, *New England Power Generators Assoc., Inc. v. FERC*, 881 F.3d 202, 210 (D.C. Cir. 2018) (remanding to FERC its decision to treat new generation capacity market entrants differently from existing capacity due to lack of reasoned explanation for departing from past precedent).

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VI. CONTENTS OF THIS FILING

A. Attachment A - Clean Tariff revisions to the PJM Tariff as follows:

- New section 217.8 to the PJM Tariff, Part VI;
- Form of Network Upgrade Funding Agreement (Attachment O-2 to the PJM Tariff); and
- Revised Table of Contents to the PJM Tariff;

B. Attachment B - Marked Tariff Revisions to the PJM Tariff;

C. Attachment C – Affidavit of David W. Weaver, P.E., Vice President of Transmission Strategy of Exelon (discussing the operational risks to the PJM Transmission Owners associated with owning and operating Network Upgrades);

D. Attachment D – Affidavit of David Hunger and Seabron Adamson and of Charles River Associates (describing the financial risks faced by the PJM Transmission Owners);

E. Attachment E – An Example of the Charge Calculation under the NUFA; and

F. Attachment F – PJM Transmission Owners' Presentation to PJM Stakeholders on April 27, 2021.

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VII. COMMUNICATIONS AND SERVICE

Correspondence and communications regarding this filing should be sent to the following individuals, who should be placed on the official service list in this proceeding.

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Chair of the Transmission Owners
Agreement Administrative Committee

VIII. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[133] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

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[133] 18 C.F.R. §§ 35.2(e), 385.2010(f)(3).

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IX. CONCLUSION

For the reasons set forth above, the PJM Transmission Owners request that the Commission accept the Proposed Revisions without hearing, modification, or condition and grant an effective date of sixty-one days after the date of the filing or August 30, 2021.

Respectfully submitted,

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Counsel for PPL Electric Utilities

On behalf of the PJM Transmission Owners

ATTACHMENT A

CLEAN TARIFF

TABLE OF CONTENTS

ATTACHMENT GG - APPENDIX III – GENERAL TERMS AND CONDITIONS

ATTACHMENT PP – FORM OF FIRM TRANSMISSION FEASIBILITY STUDY AGREEMENT

Section 217.8 Interconnected Transmission Owner Initial Funding of Network Upgrades:

(a) Interconnected Transmission Owner's Right: Notwithstanding anything in this Tariff to the contrary, the Interconnected Transmission Owner shall have the right to elect to fund the capital cost for the Network Upgrades (including Direct Connection Network Upgrades and Non-Direct Connection Network Upgrades) associated with the interconnection of an Interconnection Customer, including in cases where the Interconnection Customer exercises the Option to Build under Interconnection Construction Service Agreement, Tariff, Attachment P, Appendix 2, section 3.2.3.1. If the Interconnected Transmission Owner elects to fund the capital costs of the Network Upgrades, the Interconnected Transmission Owner shall provide the Transmission Provider and Interconnection Customer with written notice pursuant to Tariff, Part VI, section 217.8, and the Parties shall enter into a Network Upgrade Funding Agreement to memorialize the terms of repayment for those Network Upgrades that the Interconnected Transmission Owner elected to self-fund. The Network Upgrade Funding Agreement shall take the form of the *pro forma* Network Upgrade Funding Agreement that is included in Tariff, Attachment O-2. The Interconnection Customer or Interconnected Transmission Owner may request in writing that Transmission Provider file the Network Upgrade Funding Agreement with FERC in unexecuted form.

(b) Definition: Interconnected Transmission Owner is defined in Tariff, Part I, section 1. However, for purposes of this section and the Network Upgrade Funding Agreement, Interconnected Transmission Owner may also refer to a Transmission Owner whose facilities must be upgraded pursuant to a Facilities Study, but whose facilities are not directly interconnected with those of the Interconnection Customer.

(c) Timing: Transmission Provider will maintain on its website an Interconnected Transmission Owner's general non-binding indication as to whether the Interconnected Transmission Owner intends to elect to fund the capital costs (self-fund) for Network Upgrades. Transmission Provider will also maintain on its website a list of the projects for which an Interconnected Transmission Owner has elected to self-fund Network Upgrades. Each impacted Interconnected Transmission Owner shall indicate whether it intends to self-fund each specific Network Upgrade prior to the completion of the Facilities Study. Any such election to self-fund Network Upgrades shall be identified in the Facilities Study or Interconnected Transmission Owner shall be deemed to have waived its self-fund election option for the Network Upgrades identified in the Facilities Study.

If the Interconnected Transmission Owner has elected to fund the capital for the Network Upgrades, the Transmission Provider shall tender to the Interconnection Customer a Network Upgrade Funding Agreement at the same time that it tenders the Interconnection Construction Service Agreement. In the event that construction of facilities by more than one Interconnected Transmission Owner is required, the Transmission Provider will tender a separate Network Upgrade Funding Agreement for each such Interconnected Transmission Owner and the facilities to be constructed on its transmission system. The Transmission Provider shall provide to the Transmission Owner(s) a copy of the Network Upgrade Funding Agreement when these agreements are provided to the Interconnection Customer for execution.

Unless otherwise specified in the project specific milestones of the Interconnection Service Agreement, Interconnection Customer either shall have executed the tendered Network Upgrade Funding Agreement and it must be in the possession of the Transmission Provider and the Interconnected Transmission Owner at the same time as the executed Interconnection Construction Service Agreement, or, alternatively, shall request dispute resolution in accordance with the dispute resolution provisions of the Tariff, or that the Network Upgrade Funding Agreement be filed unexecuted with the Commission. In the event that an Interconnection Customer or an Interconnected Transmission Owner has requested dispute resolution proceedings or that the Network Upgrade Funding Agreement be filed unexecuted, construction of facilities and upgrades addressed in the Network Upgrade Funding Agreement shall be deferred until any disputes are resolved, unless otherwise agreed by the Interconnection Customer, the Interconnected Transmission Owner and the Transmission Provider.

Following execution of the Network Upgrade Funding Agreement by the Interconnection Customer, the Transmission Provider shall forward the Network Upgrade Funding Agreement to the Interconnected Transmission Owner named as party to the Network Upgrade Funding Agreement. The Interconnected Transmission Owner shall execute and return the Network Upgrade Funding Agreement to the Transmission Provider no later than fifteen (15) Business Days following date of receipt of Network Upgrade Funding Agreement from the Transmission Provider, or, alternatively, request that the Network Upgrade Funding Agreement be filed unexecuted with the Commission unless the Interconnected Transmission Owner requests dispute resolution under the Tariff. However, in the event the Interconnection Customer has made changes to the Network Upgrade Funding Agreement tendered to the Interconnection Customer by the Transmission Provider which were not previously reviewed and approved by a representative of the Interconnected Transmission Owner, the requirement for the Interconnected Transmission Owner to return the document in the time specified shall not be applicable and the parties to the Network Upgrade Funding Agreement shall use due diligence to execute the Network Upgrade Funding Agreement as expeditiously as possible. In the event the Interconnected Transmission Owner does not execute and return the Network Upgrade Funding Agreement in the time specified above, the Transmission Provider shall advise the Interconnection Customer of the status of the execution of the Network Upgrade Funding Agreement. The Interconnection Customer may then request: (i) dispute resolution under the Tariff; or (ii) that the Network Upgrade Funding Agreement be filed unexecuted with the Commission. In all cases, the Interconnection Customer, Interconnected Transmission Owner, and Transmission Provider may mutually agree to extend the time in which Interconnected Transmission Owner must execute and return the Network Upgrade Funding Agreement.

(d) Cross-Defaults: A breach by the Interconnection Customer of any provision, covenant, or other term or condition contained in the Network Upgrade Funding Agreement shall be considered a breach under the Interconnection Service Agreement. Such breach shall be subject to the terms of the Interconnection Service Agreement, Appendix 2, section 15. If the default under the Interconnection Service Agreement results from the Interconnection Customer's breach of the Network Upgrade Funding Agreement and subsequent failure to cure, the Interconnected Transmission Owner and the Transmission Provider shall be entitled, but in no event required, to apply all rights and remedies available by reason of default under the Interconnection Service Agreement and the Network Upgrade Funding Agreement.

(e) Interconnected Transmission Owner's Reimbursement Obligations under the Option to Build: If the Interconnection Customer exercises the Option to Build under the Interconnection Construction Service Agreement and the Interconnected Transmission Owner has elected to fund the Network Upgrades pursuant to this section 217.8, then prior to the Interconnection Customer incurring any construction costs relating to the Option to Build and by the date specified in the Interconnection Construction Service Agreement, Schedule J, the Interconnection Customer shall provide Transmission Provider a quarterly statement of Interconnection Customer's scheduled expenditures during the next three months for the design, engineering and construction of, and/or for other charges related to the Network Upgrades. Transmission Provider shall invoice the Interconnected Transmission Owner on behalf of the Interconnection Customer for the estimated amount to be expended by the Interconnection Customer to construct any Network Upgrades for which the Interconnection Customer has exercised its Option to Build. Transmission Provider shall invoice Interconnected Transmission Owner on a quarterly basis for the costs estimated to be expended in the subsequent three months. Interconnected Transmission Owner shall pay Transmission Provider within twenty (20) calendar days of receipt of the invoice. Upon receipt of Interconnected Transmission Owner's payments, Transmission Provider shall remit to the Interconnection Customer. The timing of quarterly invoices and payments shall ensure that payment is received by Interconnection Customer prior to the date by which Interconnection Customer must make any construction payment for such Network Upgrades.

Interconnected Transmission Owner may request in the Network Upgrade Funding Agreement that the Transmission Provider provide a quarterly cost reconciliation. Such a quarterly cost reconciliation will have a one-quarter lag, e.g., reconciliation of costs for the first calendar quarter of work will be provided at the start of the third calendar quarter of work, provided, however, that this section shall govern the timing of the final cost reconciliation upon completion of the work.

After completion of the construction of Network Upgrades by the Interconnection Customer, Interconnection Customer shall provide an invoice of the final cost of the Network Upgrades and shall set forth such costs in sufficient detail to enable the Interconnected Transmission Owner to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. In the event that the actual costs exceed the estimated costs previously invoiced by Interconnection Customer and paid by Interconnected Transmission Owner, Interconnected Transmission Owner shall pay to Interconnection Customer the difference between the amount previously paid and the actual costs within thirty (30) calendar days after receipt of a final construction invoice from Interconnection Customer. In the event that the actual costs are less than the estimated costs previously invoiced by Interconnection Customer and paid by Interconnected Transmission Owner, Interconnection Customer shall refund, with interest (calculated in accordance with 18 C.F.R. Section 35.19a(a)(2)(iii)), to Interconnected Transmission Owner any amount by which the actual payment by Interconnected Transmission Owner for estimated costs exceeds the actual costs of construction within thirty (30) calendar days of the issuance of such final construction invoice. Following the transfer of the Network Upgrades from the Interconnection Customer to the Interconnected Transmission Owner, the Interconnection Customer shall make payments for such facilities to the Interconnected

Transmission Owner pursuant to the terms and conditions of the Network Upgrade Funding Agreement among the Parties.

(f) Transition to the Implementation of the Interconnected Transmission Owner Funding Mechanism: For any Customer Facility for which the Interconnection Customer has not executed a Facilities Study Agreement on or before October 1, 2021, the Interconnected Transmission Owner shall have the right to elect to fund the Network Upgrades associated with that Customer Facility in accordance with the provisions of this section 217.8.

(g) Nothing in this section 217.8 or the Network Upgrade Funding Agreement is intended to affect in any way the rights to which an Interconnection Customer is entitled pursuant to Part VI, Subpart C, except to the extent the applicable terms of Subpart C provide otherwise.

ATTACHMENT O-2

FORM OF NETWORK UPGRADE FUNDING AGREEMENT

By and Among

PJM Interconnection, L.L.C.

and

[Interconnection Customer]

and

[Interconnected Transmission Owner]

(PJM Queue Position #___)

Network Upgrade Funding Agreement

for

(PJM Queue Position #_____)

This Network Upgrade Funding Agreement ("NUFA") is entered into by and among [___________], a [state] [corporation/limited liability company/other corporate form] (hereinafter "Interconnection Customer" or "[short name]"), [___________], a [state] [corporation/limited liability company/other corporate form] (hereinafter "Interconnected Transmission Owner" or "[short name]"), and PJM Interconnection, L.L.C., the Regional Transmission Organization for the PJM Region (hereinafter "Transmission Provider" or "PJM") to compensate Interconnected Transmission Owner for upgrades and additions to its transmission system ("Network Upgrades") necessary for Interconnection Service for the Interconnection Customer's Customer Facility under the PJM Open Access Transmission Tariff ("PJM Tariff" or "Tariff")). Interconnection Customer, Interconnected Transmission Owner, and PJM are each referred to as "Party," and collectively, as "Parties."

WHEREAS, the Parties entered into that certain Interconnection Service Agreement associated with Queue Position No. [____] ("ISA");

WHEREAS, the Interconnection Service necessary for Queue Position No. [___] requires Interconnected Transmission Owner to install Network Upgrade(s) on Interconnected Transmission Owner's transmission system consisting of Network Upgrade(s) identified in Schedule A in order for Interconnected Transmission Owner to operate and maintain the transmission system in a safe and reliable manner;

WHEREAS, in accordance with the PJM Tariff in effect at the time the ISA was executed, the Interconnected Transmission Owner has elected the self-fund option described in Tariff, Part VI, Section 217.8, and therefore will recover the return of and on the initial capital cost of the following Network Upgrade(s) from Interconnection Customer through this NUFA, as set forth in Schedule A herein;

WHEREAS, the Interconnected Transmission Owner will fund, own, operate and maintain the Network Upgrade(s);

WHEREAS, the PJM Tariff in effect at the time of execution of the ISA requires the Parties to enter into a network upgrade funding agreement in the form provided in Tariff, Attachment O-2 if the Interconnected Transmission Owner elects to self-fund the initial capital cost of the Network Upgrades;

NOW, THEREFORE, in consideration of the mutual premises and covenants hereinafter set forth and other good and valuable consideration, and intending to be legally bound hereby, the Parties hereby agree that Interconnected Transmission Owner shall recover from

Interconnection Customer the return of and on the initial capital cost of the Network Upgrade(s), under the following terms and conditions:

1. **Definitions**. Capitalized terms used in this NUFA that are not otherwise defined herein shall have the meaning provided in the PJM Tariff.

2. **Effective Date and Term**. Unless terminated earlier by mutual agreement, the effective date of this NUFA shall be the date it is executed by all Parties, or such other date as specified by FERC (the "Effective Date"). This NUFA shall continue until two hundred forty (240) months of payments for each Network Upgrade governed by this NUFA have been collected by the Transmission Provider and paid to the Interconnected Transmission Owner, unless the Parties mutually agree on a different term for this NUFA, including but not limited to a term that is consistent with the term of the ISA, or such other date as mutually agreed to by the Parties from the Effective Date ("Term").

3. **Network Upgrade Charge**.

3.1 Monthly Payments. Beginning with the month following notification from Interconnected Transmission Owner to Interconnection Customer and Transmission Provider, consistent with the notice requirements of Section 10.1, that a Network Upgrade has been placed in service ("In-Service Date") and continuing for the Term of this NUFA, Transmission Provider shall invoice Interconnection Customer on behalf of the Interconnected Transmission Owner, for the amount of monthly revenue requirement for that Network Upgrade. Interconnection Customer shall pay each invoice within twenty (20) days after receipt thereof ("Monthly Due Date"). Upon receipt of each of Interconnection Customer's payments, Transmission Provider shall reimburse the Interconnected Transmission Owner.

3.2 Annual Payments. Alternatively, Interconnection Customer may elect to switch from receiving monthly invoices from the Transmission Provider for the Network Upgrades to an annual invoice after the first day of the next Rate Year for the Interconnected Transmission Owner following the In-Service Date of the last Network Upgrade governed by this NUFA. Rate Year shall be defined by the Interconnected Transmission Owner's Formula Rate Protocols. If Interconnection Customer chooses to receive annual bills, Transmission Provider shall bill Interconnection Customer the equivalent of twelve (12) months of payments for each calendar year until the first Network Upgrade under this NUFA to be placed in service has less than twelve (12) months of payments owing in a calendar year, after which Transmission Provider shall resume billing Interconnection Customer on a monthly basis for each Network Upgrade. In no event shall the total amount paid by Interconnection Customer for a Network Upgrade be less than the equivalent amount due if there were instead monthly payments for the entire Term of this NUFA. Interconnection Customer shall pay each invoice within twenty (20) days after receipt thereof ("Annual Due Date"). Upon receipt of each of Interconnection Customer's payments, Transmission Provider shall reimburse the Interconnected Transmission Owner.

3.3 Initial Payments. The initial Payment(s) shall be based on the Estimated Network Upgrade Initial Capital Cost ("ENUC") and is set forth in the table below.

Description	**Amount**
ENUC (*Schedule B, Line* ___)	$___________
Levelized Fixed Charge Rate (*Schedule B, Line* ___)	_________ %
Annual revenue requirement (*Schedule B, Line* ___)	$___________
Payment (*Schedule B, Line* ___)	$___________

3.4 Updates to Payments. The Interconnection Customer payment amount for the Network Upgrade(s) shall be updated as Network Upgrades subject to this NUFA are placed in service and shall be re-calculated annually to be effective on the first day of the Rate Year for the Interconnected Transmission Owner by updating certain inputs to the formula shown in Schedule B of this NUFA ("Formula"), and rounded to the nearest whole dollar. The Formula calculates a levelized fixed charge rate ("Levelized Fixed Charge Rate") and the payment amount based on the ENUC or the Actual Network Upgrade Initial Capital Cost ("ANUC"), as applicable, the Term of this NUFA in years, and certain historic, actual data from the Interconnected Transmission Owner's transmission formula rate included in Tariff, Attachment H ("Transmission Formula Rate") or successor rate under the PJM Tariff, including but not limited to: (i) the Interconnected Transmission Owner's combined tax rate, (ii) the amounts of Interconnected Transmission Owner interest on long-term debt, (iii) the long-term debt and common equity balances, and (iv) Interconnected Transmission Owner's FERC-approved return on equity. Beginning on the first day of the Interconnected Transmission Owner's Rate Year of the first or second calendar year following the In-Service Date, as applicable based on when the ANUC is determined, and each subsequent Rate Year thereafter, the payment amount shall be updated based on the Interconnected Transmission Owner's Transmission Formula Rate using data from the previous calendar year and the ANUC. Any adjustment to the relevant inputs to Interconnected Transmission Owner's Transmission Formula Rate or successor rate under the PJM Tariff used in the Formula shall require a recalculation of the Formula for the period to which such adjustment applies and shall require revised payment amounts, as well as refunds or surcharges, as necessary. Interconnected Transmission Owner shall provide Interconnection Customer with notice each year of the change in payment amount as a result of annual changes to its Transmission Formula Rate.

3.5 Information Sharing. The Interconnected Transmission Owner and Interconnection Customer shall make available to the other Parties information necessary to verify costs incurred by the other Parties for which the requesting Party is responsible under this Agreement and carry out obligations and responsibilities under this NUFA; provided, however, that the Parties shall not use such information for purposes other than those set forth in this Section 3 and to enforce their rights under this NUFA.

3.6 Audit. Subject to the requirements of confidentiality under Section 9.2 of this NUFA: (i) the accounts and records related to the design, engineering, procurement, and construction of the Network Upgrades and/or System Protection Facilities shall be subject to audit for a period of twenty-four (24) months following the In-Service Date of each such Network Upgrade; (ii) the accounts and records related to the one-time true-up adjustment provided for in Section 3.7 shall be subject to audit for a period of twenty-four (24) months following the date the true-up adjustment is reflected in the Interconnection Customer's invoice;

and (iii) the accounts and records related to the annual inputs to the Formula shall be subject to audit for a period of twelve (12) months following each year's Formula update in accordance with this Section 3. Interconnection Customer at its expense shall have the right, during normal business hours, and upon prior reasonable notice to the other Parties, to audit such accounts and records. Any audit authorized by this Section 3 shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this NUFA.

3.7 Payment True-Up to Actual Costs. A one-time true-up adjustment shall be calculated within one (1) year of the In-Service Date when the ANUC is known and all costs associated with the ENUC have been accounted for. The true-up adjustment will be equal to the difference between payments collected to-date and what the payments to-date would have been if the payments had been calculated using the ANUC. The true-up adjustment, either as a credit due or charge to the Interconnection Customer, shall be included in the Interconnection Customer's next payment due, including interest. Interest on the true-up adjustment will begin to accrue the first day of the month following the In-Service Date and will be determined based on the Commission's regulations at 18 C.F.R. § 35.19a. Transmission Provider will invoice Interconnection Customer upon determination of the true-up in accordance with this Section 3.7.

4. **Security**

4.1 Provision of Security; Updating Security Amount. The Interconnection Customer shall provide a letter of credit from a reasonably acceptable provider, or other form of reasonably acceptable security that names either the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or the Interconnected Transmission Owner as applicable, as the beneficiary in an amount equal to the ENUC (the "Security"). The Interconnection Customer shall have the option to provide the Security to either the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or the Interconnected Transmission Owner and shall notify all Parties of its election within ten (10) days of receipt of the NUFA from the Transmission Provider. The entity whom the Interconnection Customer chooses to provide with the Security, either the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or the Interconnected Transmission Owner, shall determine whether the letter of credit or other form of security is reasonably acceptable. The Security shall be provided to Transmission Provider or Interconnected Transmission Owner, as applicable, by Interconnection Customer pursuant to this Section 4.1 within the later of: (i) forty-five (45) days of the execution of this NUFA by all Parties; (ii) forty-five (45) days of acceptance of this NUFA by FERC if this NUFA is filed unexecuted and the Security is being protested by Interconnection Customer; or (iii) forty-five (45) days of the date of filing of this NUFA if it is filed unexecuted and the Security is not being protested by Interconnection Customer. To the extent that the Interconnection Customer has provided Security under the ISA for any portion of the Network Upgrades covered by the NUFA, the Security required under this NUFA shall be reduced by the amount of Security required under the ISA for such Network Upgrades. Prior to the release of the Security under the ISA for the Network Upgrades by the Transmission Provider, the Interconnection Customer shall provide additional Security to the Interconnected Transmission Owner or Transmission Provider, as applicable, under this NUFA in an amount that is equal to the amount of Security for the Network Upgrades released under the ISA. The Security provided under the ISA may be applied to satisfy the Security requirements under the NUFA if the form, terms, and provider of the Security provided under the ISA allow it. In no event shall Interconnection Customer allow Security to lapse between the ISA and this NUFA. The Interconnection Customer must maintain the Security required under this NUFA or the ISA at all times. Likewise, in no event shall Interconnection Customer be required to maintain concurrently the full amount of Security under the ISA and the full amount of Security under this NUFA. The Security may be adjusted to an amount equal to the ANUC after such time that the one-time true-up adjustment as described in Section 3.7 is completed for each Network Upgrade. The Security shall remain with Transmission Provider or Interconnected Transmission Owner, as applicable, for the remaining months of the Term. At Interconnection Customer's discretion, such Security may be reduced by five percent (5%) (or a prorated portion based on the Term of this NUFA, as agreed by the Parties) of the ANUC of each Network Upgrade on the first anniversary of the In-Service Date of that Network Upgrade and may continue to be reduced by five percent (5%) (or a prorated portion based on the Term of this NUFA, as agreed by the Parties) each year over the Term of this NUFA, provided that any such reduction in the amount of Security must be evidenced to either the Transmission Provider or the Interconnected Transmission Owner, as applicable, in the form of a revised form of Security reasonably acceptable to the Interconnected Transmission Owner.

4.2 Draws on Security. In the event Interconnection Customer fails to make a payment by the Monthly Due Date or Annual Due Date, as applicable, Transmission Provider or Interconnected Transmission Owner, as applicable, shall be entitled to draw on the Security posted by Interconnection Customer in the amount of the missed Payments as well as any accrued interest charges based on the Commission's regulations at 18 C.F.R § 35.19a. If Interconnection Customer fails to make payment by the Monthly Due Date or Annual Due Date, as applicable, and Security has been depleted, Interconnection Customer shall provide to the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or Interconnected Transmission Owner, as applicable based on the election in Section 4.1 new irrevocable security, in a form reasonably acceptable ("New Security") within thirty (30) days of the holder's demand for New Security.

4.3 Security Requirements. Security shall remain in place until expiration of this NUFA. Any Security provided by Interconnection Customer must be kept active, must continue to meet the security requirements of the Interconnected Transmission Owner or the Transmission Provider, as applicable, and must be available to Transmission Provider or Interconnected Transmission Owner, as applicable, for the purpose of making payments under this NUFA in the event that Interconnection Customer fails to make such payment. Any fees or costs associated with the provision of security are the responsibility of the Interconnection Customer.

4.4 Tax Gross-Up. Interconnection Customer acknowledges that the construction of the Network Upgrade(s) under the ISA could be subject to tax gross-up, as applicable, upon the Interconnection Customer's default under this NUFA and that the Security provided hereunder could be used to cover such obligations.

5. **Breach, Default, and Cross-Default**

5.1 General. Upon a Breach of this NUFA, the non-breaching Party or Parties shall give written notice of such Breach to the Breaching Party with a copy to all non-breaching Parties. The Breaching Party shall have thirty (30) days from receipt of the notice of Breach within which to cure such Breach; provided, however, if such Breach is not capable of cure within thirty (30) days, the Breaching Party shall commence such cure within thirty (30) days after notice thereof and shall continuously and diligently complete such cure within ninety (90) days from receipt of the notice of Breach. If cured within such time provided by the foregoing, the Breach specified in such notice shall be deemed cured and treated by the Parties as if it had not occurred. If a Breach is not cured as provided in this Section 5.1, or is not capable of being cured within the period provided for herein, the Breaching Party shall be in default under this NUFA.

5.2 Interconnection Customer Default. Interconnection Customer shall be in default of this NUFA if Interconnection Customer: (i) fails to make two (2) consecutive monthly Payments when due or be more than sixty (60) days late in providing an annual payment; provided that, Transmission Provider has given Interconnection Customer notice of and Interconnection Customer has failed to cure such late payments consistent with Section 5.1; (ii) fails to provide New Security within thirty (30) days of the demand for New Security consistent with Section 4.2; (iii) terminates operation of its Customer Facility prior to the end of the Term of this NUFA; or (iv) is declared to be in Default under its ISA. In the event of default, Interconnection Customer shall promptly pay to Transmission Provider all Payments still owed under this NUFA. In the event that Interconnection Customer does not promptly pay all amounts due and owing to the Transmission Provider, the Transmission Provider may draw on the remaining balance of the Security provided by the Interconnection Customer. This payment or draw on the Security does not limit any and all rights and remedies available to the Transmission Provider or Interconnected Transmission Owner allowed by law with respect to such default or collecting all amounts owed for the remaining months due under this NUFA. Interconnection Customer shall indemnify Transmission Provider and Interconnected Transmission Owner for reasonable costs, attorney fees and/or expenses incurred with respect to a default or collecting all amounts owed for the remaining months, including, as applicable, any tax gross-up obligations under this NUFA.

5.3 Interconnected Transmission Owner Default. Interconnected Transmission Owner shall be in default of this NUFA if Interconnection Transmission Owner: (i) fails to provide Interconnection Customer with any of the information access and audit rights provided in Section 3.6; (ii) such failure is not cured following notice from Interconnection Customer as provided in Section 5.1; and (iii) such failure has a material adverse effect on Interconnection Customer's ability to perform under this NUFA.

5.4 Cross-Default. This NUFA is a requirement for Interconnection Service under the PJM Tariff when an Interconnected Transmission Owner has elected to fund the capital for the Network Upgrades and shall be subject to the terms and conditions of the PJM Tariff, including the rights to termination of Interconnection Service. Notwithstanding anything to the contrary contained in this NUFA, a Breach by Interconnection Customer of any provision, covenant or other term or condition contained in this NUFA shall be considered a Breach under the Interconnection Customer's ISA referenced in the recitals to this NUFA. An event of default by Interconnection Customer under Section 5.2 hereof shall, after the passage of all applicable notice and cure or grace periods, be considered a default under this NUFA and a default of the Interconnection Customer's ISA referenced in the recitals to this NUFA. Interconnected Transmission Owner and Transmission Provider shall be entitled (but in no event required) in an event of such dual Breach or default to apply all rights and remedies available in this NUFA and the ISA by reason of a Breach or default.

5.5 Notice of Default. In the event of a default under Interconnection Customer's ISA, Transmission Provider shall provide prompt notice of such default to all affected Transmission Owners that have FERC-filed service agreements with Interconnection Customer under the PJM Tariff.

6. **Reimbursed Network Upgrades**

Following the execution of this NUFA, if the Transmission Provider determines that any portion of the costs of the Network Upgrades covered by this NUFA should be allocated to one or more subsequent Customer Facilities ("New Customer(s)"), the Parties shall amend this NUFA and/or enter into new agreements in the form provided in Tariff, Attachment O-2 to reflect Interconnection Customer and New Customer's (or New Customers') respective responsibility for the remaining costs of the Network Upgrade subject to this NUFA based on the effective date of New Customer's ISA.

7. **Assignment**

This NUFA shall inure to the benefit of and be binding upon each Party's successors and permitted assigns. No Party shall assign this NUFA or their related contractual rights without the prior written consent of the other Parties, which prior written consents shall be not be unreasonably withheld or delayed; provided that the assignee is at least as creditworthy as the assigning Party and the assignee of the Interconnection Customer shall provide Interconnected Transmission Owner with Security as contemplated herein; and provided further that Interconnection Customer shall have the right to assign this NUFA, without the consent of either the Transmission Provider or the Interconnected Transmission Owner, for collateral security purposes to aid in providing financing for the Customer Facility, provided that Interconnection Customer will promptly notify Transmission Provider and Interconnected Transmission Owner of any such assignment. No assignment of this NUFA shall release or discharge any Party from their future obligations hereunder unless all such obligations are assumed by the successor or assignee of that Party in writing.

8. **No Transmission Service**

The execution of a NUFA does not constitute a request for transmission service, or entitle Interconnection Customer to receive transmission service, under Tariff, Part II or Tariff, Part III. Nor does the execution of an NUFA obligate Interconnected Transmission Owner or Transmission Provider to procure, supply or deliver to Interconnection Customer or the Customer Facility any energy, capacity, Ancillary Services or Station Power (and any associated distribution services).

9. **<u>Miscellaneous</u>**

9.1 Entire Agreement. This NUFA represents the entire agreement among the Parties with reference to payment terms for the Network Upgrade(s) provided by Interconnected Transmission Owner for Interconnection Customer under the ISA. This NUFA may not be amended, modified, or waived other than by a written document signed by all Parties.

9.2 Confidentiality

9.2.1 Definition. Confidential Information under this NUFA shall have the same meaning as provided in the PJM Tariff. Critical Energy/Electric Infrastructure Information ("CEII") shall have the meaning provided in 18 C.F.R. § 388.113(c)(1)-(2).

9.2.2 Term. During the Term of this NUFA, and for a period of three (3) years after the expiration or termination of the NUFA, except as otherwise provided in this Section 9.2 or with regard to CEII, each Party shall hold in confidence, and shall not disclose to any person, Confidential Information provided to it by any other Party. In addition to being treated as Confidential Information hereunder, CEII shall be treated in accordance with Commission policy and regulations.

9.2.3 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (i) is generally available to the public other than as a result of a disclosure by the receiving Party; (ii) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (iii) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party, after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (iv) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (v) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this NUFA; or (vi) is required, in accordance with Section 9.2.8, to be disclosed to any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this NUFA. Information designated as Confidential Information shall no longer be deemed confidential if the Party that designated the information as confidential notifies the other Parties that it no longer is confidential.

9.2.4 Release of Confidential Information. No Party shall disclose Confidential Information to any other person, except to its Affiliates (limited by the Commission's Standards of Conduct for Transmission Providers, 18 C.F.R. Part 358), subcontractors, employees, agents, consultants, or to non-parties who may be or are considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this NUFA, unless such person has first been advised of the confidentiality provisions of this Section 9.2 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 9.2.

9.2.5 Rights. Each Party retains all rights, title, and interest in the Confidential Information that it discloses to any other Party. The disclosure by a Party to the receiving Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure. Nothing in this NUFA shall limit or otherwise modify Transmission Provider's rights and obligations with respect to Confidential Information as set forth in the PJM Tariff.

9.2.6 No Warranties. By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

9.2.7 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this NUFA or its regulatory requirements.

9.2.8 Order of Disclosure. If a Governmental Authority with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the disclosing Party with prompt notice of such request(s) or requirement(s) so that the disclosing Party may seek an appropriate protective order or waive compliance with the terms of this NUFA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

9.2.9 Termination of Agreement. Upon termination of this NUFA for any reason, each Party shall, within ten (10) days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the requesting Party) or return to the requesting Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the requesting Party.

9.2.10 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's breach of its obligations under this Section 9.2. Each Party accordingly agrees that the disclosing Party shall be entitled to equitable relief, by way of injunction or otherwise, if the receiving Party breaches or threatens to breach its obligations under this Section 9.2, which equitable relief shall be granted without bond or proof of damages, and the breaching Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the breach of this Section 9.2, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 9.2.

9.2.11 Disclosure to FERC or its Staff. Notwithstanding anything in this Section 9.2 to the contrary, and pursuant to 18 C.F.R. § 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from a Party that is otherwise required to be maintained in confidence pursuant to this NUFA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this NUFA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to this NUFA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. § 388.112.

9.2.12 Competitively Sensitive Information. Subject to the exception in Section 9.2.11, any information that a disclosing Party claims is competitively sensitive, commercial or financial information under this NUFA shall not be disclosed by the receiving Party to any person not employed or retained by the receiving Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the receiving Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the disclosing Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this NUFA or as the Regional Transmission Organization including disclosing the Confidential Information to a regional or national reliability organization. The Party asserting confidentiality shall notify the receiving Party in writing of the information that Party claims is confidential. Prior to any disclosures of that Party's Confidential Information under this Section 9.2.12, or if any non-Party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the Party who received the Confidential Information from the disclosing Party agrees to promptly notify the disclosing Party in writing and agrees to assert confidentiality and cooperate with the disclosing Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

9.3 Regulatory Approval. This NUFA and its terms shall be subject to approval, if applicable, by the Commission. This NUFA and its terms shall also be subject to, as applicable, the PJM Tariff.

9.4 Force Majeure.

9.4.1 Notice. A Party that is unable to carry out an obligation imposed on it by this NUFA due to Force Majeure shall notify the other parties in writing or by telephone within a reasonable time after the occurrence of the cause relied on.

9.4.2 Duration of Force Majeure. A Party shall not be responsible, or considered to be in Breach or default under this NUFA, for any failure to perform any obligation hereunder to the extent that such failure or deficiency is due to Force Majeure. A Party shall be excused from whatever performance is affected only for the duration of the Force Majeure and while the Party exercises Reasonable Efforts to alleviate such situation. As soon as the non-performing Party is able to resume performance of its obligations excused because of the occurrence of Force Majeure, such Party shall resume performance and give prompt notice thereof to the other parties.

9.4.3 Obligation to Make Payments. Any Party's obligation to make payments for services shall not be suspended by Force Majeure.

9.4.4 Definition of Force Majeure. For purposes of this section, an event of Force Majeure shall mean any cause beyond the control of the affected Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by exercise of due diligence such Party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force Majeure does not include (i) a failure of performance that is due to an affected Party's own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected Party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected Party.

9.5 Disputes. Any dispute hereunder shall be referred to senior representatives of each Party. If the senior representatives are not able to resolve the dispute within thirty (30) days, the dispute resolution procedures of Tariff, Part I section 12 and Tariff, Part IV, section 40 shall apply to the resolution of any dispute hereunder.

9.6 Reservation of Rights. Nothing in this NUFA shall limit the rights of the Parties or of FERC under Section 205 and 206 of the Federal Power Act and FERC's rules and regulations thereunder.

9.7 Liability. A party shall not be liable to another Party or to any third party or other person for any damages arising out of actions under this NUFA, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of Interconnection Service, except as provided in the PJM Tariff. The provisions set forth in the PJM Tariff shall be additionally applicable to any Party acting in good faith to implement or comply with its obligations under this NUFA, regardless of whether the obligation is preceded by a specific directive.

9.8 Governing Law. This NUFA is governed by and shall be construed in accordance with laws of the State of Delaware, without regard for any principles of conflicts of laws.

9.9 No Waiver. It is mutually understood that any failure by Transmission Provider or Interconnected Transmission Owner or inconsistency to enforce or require the strict keeping and performance by Interconnection Customer of any of the provisions of this NUFA shall not constitute a waiver by Transmission Provider or Interconnected Transmission Owner of such provisions, and shall not affect or impair such provisions in any way, or the right of Transmission Provider or Interconnected Transmission Owner at any time to avail itself of such remedies as it may have for any breach or breaches of such provisions. The waiver, illegality, invalidity and/or unenforceability of any provision appearing in this NUFA shall not affect the validity of this NUFA as a whole or the validity or any other provisions therein.

9.10 Waiver of Jury Trial. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS NUFA. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

10. **Notice**

10.1 General. Any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address specified in Section 10.2. Such notices, if agreed to by the Parties, may be made via electronic means, with e-mail confirmation of delivery.

10.2 Contacts. Any Party may update its contact information by providing notice to the other Parties in accordance with Section 10.1.

Interconnected Transmission Owner	
[Name]	[Business Address]
[Company or Organization]	[City, State Zip]
	[Email]
Interconnection Customer	
[Name]	[Business Address]
[Company or Organization]	[City, State Zip]
	[Email]
Transmission Provider	
[Name]	2750 Monroe Blvd
PJM Interconnection, L.L.C.	Audubon, PA 19403
	[Email]

SIGNATURE PAGE FOLLOWS

IN WITNESS WHEREOF, Transmission Provider, Interconnection Customer and Interconnected Transmission Owner have caused this NUFA to be executed by their respective authorized officials.

(PJM Queue Position #___)

Transmission Provider: **PJM Interconnection, L.L.C.**

____

By: ______________________ ______________________ _______________
Printed Name Title Date

Interconnection Customer: **[Name of Party]**

____

By: ______________________ ______________________ _______________
Printed Name Title Date

Interconnected Transmission Owner:

____

By: ______________________ ______________________ _______________
Printed Name Title Date

Schedule A

Network Upgrade Facilities

Schedule B

Formula Rate Exhibit

Line			
	PJM TO @		
1	**21% FIT**		
2	**Schedule B**		
3			
4	**<u>Levelized Fixed Charge Rate Calculation with Deferred Recovery</u>**		
5	**(Blank Template)**		
6			
7	Project Name:	20XX Network Upgrade project	
8			
9	Description	20XX Network Upgrade project	
10			
11	Cost Year:	20XX Actual True-up	
12			
13	Estimated or Actual Cost and ISD:	Actual cost; Actual ISD 6/1/20XX	
14			
15	Rate Recovery Period:	June 1, 20XX thru May 31, 20XX	
16			
17	Levelized Fixed Charge Computation:		
18			
19	Initial Network Upgrade Capital Cost		$0
20	Levelized FCR with Deferred Recovery	(Line 57)	0.0000%
21	Annual Network Upgrade Charge	(Line 19 x Line 20)	$0
22	Monthly Payment	(Line 21 / 12)	$0
23			
24	Fixed Charge Rate Calculation:		
25			
26	Investment	(Line 19)	0
27			
28	PW Federal Tax Depreciation	[Line 109, Col (f)]	0
29	Applicable federal tax rate	(Line 64)	0.00%
30	PW Federal Tax Benefit	(Line 28 x Line 29)	0
31			
32	PW State Tax Depreciation	[Line 109, Col (g)]	0
33	Applicable state tax rate	(Line 65)	0.00%
34	PW State Tax Benefit	(Line 32 x Line 33)	0
35			
36	PW Tax Benefit	(Line 30 + Line 34)	0
37	Present Worth Cashflow	(Line 26 - Line 36)	0
38	Revenue Conversion Factor	[1/(1 - Line 63)]	1.0000

39	Present Worth Revenue Requirement		(Line 37 x Line 38)	0
40				
41	In Service Date			6/1/2021
42	Recovery Start Date			6/1/2021
43	Deferral Days (February counted as 28 days)			0
44	Deferral Annualization Factor (based on 365 days)		(Line 43/365)	0.0000%
45	Discount Rate per Year		(Line 75)	0.0000%
46	Deferral Factor		{[(1+Line 45)^Line 44] - 1}	0.0000%
47	Deferral Adjustment		(Line 39 x Line 46)	0
48				
49	Present Worth with Deferred Recovery		(Line 39 + Line 47)	0
50				
51	Recovery Period (RP)			20
52	Annualization Factor		{ i [(1+i)^RP]} / {[(1+i)^RP] -1}	0.0000%
53			(where RP is Line 51, and i is Line 45)	
54				
55	Levelized Amount		(Line 49 x Line 52)	0
56				
57	Levelized Fixed Charge Rate (FCR)		(Line 55 / Line 26)	0.0000%
58				
59				
60	Project Name: 20XX Network Upgrade project			
61				
62	Inputs from Formula Rate True-up Filing			
63	Combined Tax Rate	0.00%		
64	Applicable Federal Income Tax Rate	0.00%		
65	Applicable State Income Tax Rate	0.00%		
66				
67				

68	Capital Structure	Amount	Weight	Cost	Weighted Cost
69					
70	Long-Term Debt	0	0.00%	0.00%	0.0000%
71	Preferred Stock	0	0.00%	0.00%	0.0000%
72	Common Equity	0	0.00%	0.00%	0.0000%
73	Total Capitalization	0	0.00%		0.0000%

74

75 Discount Rate (Line 73 - (Line 63 x Line 70)) 0.0000%

76

77

78

79

80 MACRS Depreciation Rates with Bonus Depreciation Option:

81

Line	(a) Year	(b) MACRS Rates	(c) MACRS Depr	(d) State Depr	(e) Present Worth Factor 1/(1+i)^n	(f) Present Worth Federal Tax Depreciation	(g) Present Worth State Tax Depreciation
87							
88	Base	(Line 19)	$0	$0			
89	1	0.00%	0		1.000000	0	
90	Remaining Base	(Line 88-Line 89)	0.0				
91							
92	1	5.00%	0	0	1.000000	0	0
93	2	9.50%	0	0	1.000000	0	0
94	3	8.55%	0	0	1.000000	0	0
95	4	7.70%	0	0	1.000000	0	0
96	5	6.93%	0	0	1.000000	0	0
97	6	6.23%	0	0	1.000000	0	0
98	7	5.90%	0	0	1.000000	0	0
99	8	5.90%	0	0	1.000000	0	0
100	9	5.91%	0	0	1.000000	0	0
101	10	5.90%	0	0	1.000000	0	0
102	11	5.91%	0	0	1.000000	0	0
103	12	5.90%	0	0	1.000000	0	0
104	13	5.91%	0	0	1.000000	0	0
105	14	5.90%	0	0	1.000000	0	0
106	15	5.91%	0	0	1.000000	0	0
107	16	2.95%	0	0	1.000000	0	0
108							
109		Total	0	0		0	0

110

111 Footnote:

112 *Use Line 89 if bonus depreciation is applicable*

113

Return \ Capitalization Calculations From Transmission Formula Rate True-up Filing

Line or Note

	Response	Cap Limit %
Does the formula rate template include a Capital Structure Equity Limit (Cap)? (Yes or No)	No	

	$	Actual %	Cap Limit %	Cost (Note "X")	Weighted	
Long Term Debt	0	0.00%	0.00%	0.0000	0.0000	=WCLTD
Preferred Stock	0	0.00%	0.00%	0.0000	0.0000	
Common Stock	0	0.00%	0.00%	0.0000	0.0000	
Total Capitalization (Sum Lines to)	0				0.0000	=R

Income Tax Rates From Transmission Formula Rate True-up Filing

FIT =	0.00%
SIT=	0.00%
p =	0.00%

INCOME TAXES

T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = 0.00%

Notes:

ATTACHMENT B

MARKED TARIFF

TABLE OF CONTENTS

ATTACHMENT PP – FORM OF FIRM TRANSMISSION FEASIBILITY STUDY AGREEMENT

Section 217.8 Interconnected Transmission Owner Initial Funding of Network Upgrades:

(a) Interconnected Transmission Owner's Right: Notwithstanding anything in this Tariff to the contrary, the Interconnected Transmission Owner shall have the right to elect to fund the capital cost for the Network Upgrades (including Direct Connection Network Upgrades and Non-Direct Connection Network Upgrades) associated with the interconnection of an Interconnection Customer, including in cases where the Interconnection Customer exercises the Option to Build under Interconnection Construction Service Agreement, Tariff, Attachment P, Appendix 2, section 3.2.3.1. If the Interconnected Transmission Owner elects to fund the capital costs of the Network Upgrades, the Interconnected Transmission Owner shall provide the Transmission Provider and Interconnection Customer with written notice pursuant to Tariff, Part VI, section 217.8, and the Parties shall enter into a Network Upgrade Funding Agreement to memorialize the terms of repayment for those Network Upgrades that the Interconnected Transmission Owner elected to self-fund. The Network Upgrade Funding Agreement shall take the form of the *pro forma* Network Upgrade Funding Agreement that is included in Tariff, Attachment O-2. The Interconnection Customer or Interconnected Transmission Owner may request in writing that Transmission Provider file the Network Upgrade Funding Agreement with FERC in unexecuted form.

(b) Definition: Interconnected Transmission Owner is defined in Tariff, Part I, section 1. However, for purposes of this section and the Network Upgrade Funding Agreement, Interconnected Transmission Owner may also refer to a Transmission Owner whose facilities must be upgraded pursuant to a Facilities Study, but whose facilities are not directly interconnected with those of the Interconnection Customer.

(c) Timing: Transmission Provider will maintain on its website an Interconnected Transmission Owner's general non-binding indication as to whether the Interconnected Transmission Owner intends to elect to fund the capital costs (self-fund) for Network Upgrades. Transmission Provider will also maintain on its website a list of the projects for which an Interconnected Transmission Owner has elected to self-fund Network Upgrades. Each impacted Interconnected Transmission Owner shall indicate whether it intends to self-fund each specific Network Upgrade prior to the completion of the Facilities Study. Any such election to self-fund Network Upgrades shall be identified in the Facilities Study or Interconnected Transmission Owner shall be deemed to have waived its self-fund election option for the Network Upgrades identified in the Facilities Study.

If the Interconnected Transmission Owner has elected to fund the capital for the Network Upgrades, the Transmission Provider shall tender to the Interconnection Customer a Network Upgrade Funding Agreement at the same time that it tenders the Interconnection Construction Service Agreement. In the event that construction of facilities by more than one Interconnected Transmission Owner is required, the Transmission Provider will tender a separate Network Upgrade Funding Agreement for each such Interconnected Transmission Owner and the facilities to be constructed on its transmission system. The Transmission Provider shall provide to the Transmission Owner(s) a copy of the Network Upgrade Funding Agreement when these agreements are provided to the Interconnection Customer for execution.

Unless otherwise specified in the project specific milestones of the Interconnection Service Agreement, Interconnection Customer either shall have executed the tendered Network Upgrade Funding Agreement and it must be in the possession of the Transmission Provider and the Interconnected Transmission Owner at the same time as the executed Interconnection Construction Service Agreement, or, alternatively, shall request dispute resolution in accordance with the dispute resolution provisions of the Tariff, or that the Network Upgrade Funding Agreement be filed unexecuted with the Commission. In the event that an Interconnection Customer or an Interconnected Transmission Owner has requested dispute resolution proceedings or that the Network Upgrade Funding Agreement be filed unexecuted, construction of facilities and upgrades addressed in the Network Upgrade Funding Agreement shall be deferred until any disputes are resolved, unless otherwise agreed by the Interconnection Customer, the Interconnected Transmission Owner and the Transmission Provider.

Following execution of the Network Upgrade Funding Agreement by the Interconnection Customer, the Transmission Provider shall forward the Network Upgrade Funding Agreement to the Interconnected Transmission Owner named as party to the Network Upgrade Funding Agreement. The Interconnected Transmission Owner shall execute and return the Network Upgrade Funding Agreement to the Transmission Provider no later than fifteen (15) Business Days following date of receipt of Network Upgrade Funding Agreement from the Transmission Provider, or, alternatively, request that the Network Upgrade Funding Agreement be filed unexecuted with the Commission unless the Interconnected Transmission Owner requests dispute resolution under the Tariff. However, in the event the Interconnection Customer has made changes to the Network Upgrade Funding Agreement tendered to the Interconnection Customer by the Transmission Provider which were not previously reviewed and approved by a representative of the Interconnected Transmission Owner, the requirement for the Interconnected Transmission Owner to return the document in the time specified shall not be applicable and the parties to the Network Upgrade Funding Agreement shall use due diligence to execute the Network Upgrade Funding Agreement as expeditiously as possible. In the event the Interconnected Transmission Owner does not execute and return the Network Upgrade Funding Agreement in the time specified above, the Transmission Provider shall advise the Interconnection Customer of the status of the execution of the Network Upgrade Funding Agreement. The Interconnection Customer may then request: (i) dispute resolution under the Tariff; or (ii) that the Network Upgrade Funding Agreement be filed unexecuted with the Commission. In all cases, the Interconnection Customer, Interconnected Transmission Owner, and Transmission Provider may mutually agree to extend the time in which Interconnected Transmission Owner must execute and return the Network Upgrade Funding Agreement.

(d) Cross-Defaults: A breach by the Interconnection Customer of any provision, covenant, or other term or condition contained in the Network Upgrade Funding Agreement shall be considered a breach under the Interconnection Service Agreement. Such breach shall be subject to the terms of the Interconnection Service Agreement, Appendix 2, section 15. If the default under the Interconnection Service Agreement results from the Interconnection Customer's breach of the Network Upgrade Funding Agreement and subsequent failure to cure, the Interconnected Transmission Owner and the Transmission Provider shall be entitled, but in no event required, to apply all rights and remedies available by reason of default under the Interconnection Service Agreement and the Network Upgrade Funding Agreement.

(e) Interconnected Transmission Owner's Reimbursement Obligations under the Option to Build: If the Interconnection Customer exercises the Option to Build under the Interconnection Construction Service Agreement and the Interconnected Transmission Owner has elected to fund the Network Upgrades pursuant to this section 217.8, then prior to the Interconnection Customer incurring any construction costs relating to the Option to Build and by the date specified in the Interconnection Construction Service Agreement, Schedule J, the Interconnection Customer shall provide Transmission Provider a quarterly statement of Interconnection Customer's scheduled expenditures during the next three months for the design, engineering and construction of, and/or for other charges related to the Network Upgrades. Transmission Provider shall invoice the Interconnected Transmission Owner on behalf of the Interconnection Customer for the estimated amount to be expended by the Interconnection Customer to construct any Network Upgrades for which the Interconnection Customer has exercised its Option to Build. Transmission Provider shall invoice Interconnected Transmission Owner on a quarterly basis for the costs estimated to be expended in the subsequent three months. Interconnected Transmission Owner shall pay Transmission Provider within twenty (20) calendar days of receipt of the invoice. Upon receipt of Interconnected Transmission Owner's payments, Transmission Provider shall remit to the Interconnection Customer. The timing of quarterly invoices and payments shall ensure that payment is received by Interconnection Customer prior to the date by which Interconnection Customer must make any construction payment for such Network Upgrades.

Interconnected Transmission Owner may request in the Network Upgrade Funding Agreement that the Transmission Provider provide a quarterly cost reconciliation. Such a quarterly cost reconciliation will have a one-quarter lag, e.g., reconciliation of costs for the first calendar quarter of work will be provided at the start of the third calendar quarter of work, provided, however, that this section shall govern the timing of the final cost reconciliation upon completion of the work.

After completion of the construction of Network Upgrades by the Interconnection Customer, Interconnection Customer shall provide an invoice of the final cost of the Network Upgrades and shall set forth such costs in sufficient detail to enable the Interconnected Transmission Owner to compare the actual costs with the estimates and to ascertain deviations, if any, from the cost estimates. In the event that the actual costs exceed the estimated costs previously invoiced by Interconnection Customer and paid by Interconnected Transmission Owner, Interconnected Transmission Owner shall pay to Interconnection Customer the difference between the amount previously paid and the actual costs within thirty (30) calendar days after receipt of a final construction invoice from Interconnection Customer. In the event that the actual costs are less than the estimated costs previously invoiced by Interconnection Customer and paid by Interconnected Transmission Owner, Interconnection Customer shall refund, with interest (calculated in accordance with 18 C.F.R. Section 35.19a(a)(2)(iii)), to Interconnected Transmission Owner any amount by which the actual payment by Interconnected Transmission Owner for estimated costs exceeds the actual costs of construction within thirty (30) calendar days of the issuance of such final construction invoice. Following the transfer of the Network Upgrades from the Interconnection Customer to the Interconnected Transmission Owner, the Interconnection Customer shall make payments for such facilities to the Interconnected

Transmission Owner pursuant to the terms and conditions of the Network Upgrade Funding Agreement among the Parties.

(f) Transition to the Implementation of the Interconnected Transmission Owner Funding Mechanism: For any Customer Facility for which the Interconnection Customer has not executed a Facilities Study Agreement on or before October 1, 2021, the Interconnected Transmission Owner shall have the right to elect to fund the Network Upgrades associated with that Customer Facility in accordance with the provisions of this section 217.8.

(g) Nothing in this section 217.8 or the Network Upgrade Funding Agreement is intended to affect in any way the rights to which an Interconnection Customer is entitled pursuant to Part VI, Subpart C, except to the extent the applicable terms of Subpart C provide otherwise.

ATTACHMENT O-2

FORM OF NETWORK UPGRADE FUNDING AGREEMENT

By and Among

PJM Interconnection, L.L.C.

and

[Interconnection Customer]

and

[Interconnected Transmission Owner]

(PJM Queue Position #___)

Network Upgrade Funding Agreement

for

(PJM Queue Position #_____)

This Network Upgrade Funding Agreement ("NUFA") is entered into by and among [____________], a [state] [corporation/limited liability company/other corporate form] (hereinafter "Interconnection Customer" or "[short name]"), [____________], a [state] [corporation/limited liability company/other corporate form] (hereinafter "Interconnected Transmission Owner" or "[short name]"), and PJM Interconnection, L.L.C., the Regional Transmission Organization for the PJM Region (hereinafter "Transmission Provider" or "PJM") to compensate Interconnected Transmission Owner for upgrades and additions to its transmission system ("Network Upgrades") necessary for Interconnection Service for the Interconnection Customer's Customer Facility under the PJM Open Access Transmission Tariff ("PJM Tariff" or "Tariff")). Interconnection Customer, Interconnected Transmission Owner, and PJM are each referred to as "Party," and collectively, as "Parties."

WHEREAS, the Parties entered into that certain Interconnection Service Agreement associated with Queue Position No. [____] ("ISA");

WHEREAS, the Interconnection Service necessary for Queue Position No. [___] requires Interconnected Transmission Owner to install Network Upgrade(s) on Interconnected Transmission Owner's transmission system consisting of Network Upgrade(s) identified in Schedule A in order for Interconnected Transmission Owner to operate and maintain the transmission system in a safe and reliable manner;

WHEREAS, in accordance with the PJM Tariff in effect at the time the ISA was executed, the Interconnected Transmission Owner has elected the self-fund option described in Tariff, Part VI, Section 217.8, and therefore will recover the return of and on the initial capital cost of the following Network Upgrade(s) from Interconnection Customer through this NUFA, as set forth in Schedule A herein;

WHEREAS, the Interconnected Transmission Owner will fund, own, operate and maintain the Network Upgrade(s);

WHEREAS, the PJM Tariff in effect at the time of execution of the ISA requires the Parties to enter into a network upgrade funding agreement in the form provided in Tariff, Attachment O-2 if the Interconnected Transmission Owner elects to self-fund the initial capital cost of the Network Upgrades;

NOW, THEREFORE, in consideration of the mutual premises and covenants hereinafter set forth and other good and valuable consideration, and intending to be legally bound hereby, the Parties hereby agree that Interconnected Transmission Owner shall recover from

Interconnection Customer the return of and on the initial capital cost of the Network Upgrade(s), under the following terms and conditions:

1. **Definitions**. Capitalized terms used in this NUFA that are not otherwise defined herein shall have the meaning provided in the PJM Tariff.

2. **Effective Date and Term**. Unless terminated earlier by mutual agreement, the effective date of this NUFA shall be the date it is executed by all Parties, or such other date as specified by FERC (the "Effective Date"). This NUFA shall continue until two hundred forty (240) months of payments for each Network Upgrade governed by this NUFA have been collected by the Transmission Provider and paid to the Interconnected Transmission Owner, unless the Parties mutually agree on a different term for this NUFA, including but not limited to a term that is consistent with the term of the ISA, or such other date as mutually agreed to by the Parties from the Effective Date ("Term").

3. **Network Upgrade Charge**.

3.1 Monthly Payments. Beginning with the month following notification from Interconnected Transmission Owner to Interconnection Customer and Transmission Provider, consistent with the notice requirements of Section 10.1, that a Network Upgrade has been placed in service ("In-Service Date") and continuing for the Term of this NUFA, Transmission Provider shall invoice Interconnection Customer on behalf of the Interconnected Transmission Owner, for the amount of monthly revenue requirement for that Network Upgrade. Interconnection Customer shall pay each invoice within twenty (20) days after receipt thereof ("Monthly Due Date"). Upon receipt of each of Interconnection Customer's payments, Transmission Provider shall reimburse the Interconnected Transmission Owner.

3.2 Annual Payments. Alternatively, Interconnection Customer may elect to switch from receiving monthly invoices from the Transmission Provider for the Network Upgrades to an annual invoice after the first day of the next Rate Year for the Interconnected Transmission Owner following the In-Service Date of the last Network Upgrade governed by this NUFA. Rate Year shall be defined by the Interconnected Transmission Owner's Formula Rate Protocols. If Interconnection Customer chooses to receive annual bills, Transmission Provider shall bill Interconnection Customer the equivalent of twelve (12) months of payments for each calendar year until the first Network Upgrade under this NUFA to be placed in service has less than twelve (12) months of payments owing in a calendar year, after which Transmission Provider shall resume billing Interconnection Customer on a monthly basis for each Network Upgrade. In no event shall the total amount paid by Interconnection Customer for a Network Upgrade be less than the equivalent amount due if there were instead monthly payments for the entire Term of this NUFA. Interconnection Customer shall pay each invoice within twenty (20) days after receipt thereof ("Annual Due Date"). Upon receipt of each of Interconnection Customer's payments, Transmission Provider shall reimburse the Interconnected Transmission Owner.

3.3 Initial Payments. The initial Payment(s) shall be based on the Estimated Network Upgrade Initial Capital Cost ("ENUC") and is set forth in the table below.

Description	**Amount**
ENUC (*Schedule B, Line* ___)	$___________
Levelized Fixed Charge Rate (*Schedule B, Line* ___)	_________%
Annual revenue requirement (*Schedule B, Line* ___)	$___________
Payment (*Schedule B, Line* ___)	$___________

3.4 Updates to Payments. The Interconnection Customer payment amount for the Network Upgrade(s) shall be updated as Network Upgrades subject to this NUFA are placed in service and shall be re-calculated annually to be effective on the first day of the Rate Year for the Interconnected Transmission Owner by updating certain inputs to the formula shown in Schedule B of this NUFA ("Formula"), and rounded to the nearest whole dollar. The Formula calculates a levelized fixed charge rate ("Levelized Fixed Charge Rate") and the payment amount based on the ENUC or the Actual Network Upgrade Initial Capital Cost ("ANUC"), as applicable, the Term of this NUFA in years, and certain historic, actual data from the Interconnected Transmission Owner's transmission formula rate included in Tariff, Attachment H ("Transmission Formula Rate") or successor rate under the PJM Tariff, including but not limited to: (i) the Interconnected Transmission Owner's combined tax rate, (ii) the amounts of Interconnected Transmission Owner interest on long-term debt, (iii) the long-term debt and common equity balances, and (iv) Interconnected Transmission Owner's FERC-approved return on equity. Beginning on the first day of the Interconnected Transmission Owner's Rate Year of the first or second calendar year following the In-Service Date, as applicable based on when the ANUC is determined, and each subsequent Rate Year thereafter, the payment amount shall be updated based on the Interconnected Transmission Owner's Transmission Formula Rate using data from the previous calendar year and the ANUC. Any adjustment to the relevant inputs to Interconnected Transmission Owner's Transmission Formula Rate or successor rate under the PJM Tariff used in the Formula shall require a recalculation of the Formula for the period to which such adjustment applies and shall require revised payment amounts, as well as refunds or surcharges, as necessary. Interconnected Transmission Owner shall provide Interconnection Customer with notice each year of the change in payment amount as a result of annual changes to its Transmission Formula Rate.

3.5 Information Sharing. The Interconnected Transmission Owner and Interconnection Customer shall make available to the other Parties information necessary to verify costs incurred by the other Parties for which the requesting Party is responsible under this Agreement and carry out obligations and responsibilities under this NUFA; provided, however, that the Parties shall not use such information for purposes other than those set forth in this Section 3 and to enforce their rights under this NUFA.

3.6 Audit. Subject to the requirements of confidentiality under Section 9.2 of this NUFA: (i) the accounts and records related to the design, engineering, procurement, and construction of the Network Upgrades and/or System Protection Facilities shall be subject to audit for a period of twenty-four (24) months following the In-Service Date of each such Network Upgrade; (ii) the accounts and records related to the one-time true-up adjustment provided for in Section 3.7 shall be subject to audit for a period of twenty-four (24) months following the date the true-up adjustment is reflected in the Interconnection Customer's invoice;

and (iii) the accounts and records related to the annual inputs to the Formula shall be subject to audit for a period of twelve (12) months following each year's Formula update in accordance with this Section 3. Interconnection Customer at its expense shall have the right, during normal business hours, and upon prior reasonable notice to the other Parties, to audit such accounts and records. Any audit authorized by this Section 3 shall be performed at the offices where such accounts and records are maintained and shall be limited to those portions of such accounts and records that relate to obligations under this NUFA.

3.7 Payment True-Up to Actual Costs. A one-time true-up adjustment shall be calculated within one (1) year of the In-Service Date when the ANUC is known and all costs associated with the ENUC have been accounted for. The true-up adjustment will be equal to the difference between payments collected to-date and what the payments to-date would have been if the payments had been calculated using the ANUC. The true-up adjustment, either as a credit due or charge to the Interconnection Customer, shall be included in the Interconnection Customer's next payment due, including interest. Interest on the true-up adjustment will begin to accrue the first day of the month following the In-Service Date and will be determined based on the Commission's regulations at 18 C.F.R. § 35.19a. Transmission Provider will invoice Interconnection Customer upon determination of the true-up in accordance with this Section 3.7.

4. **Security**

4.1 Provision of Security; Updating Security Amount. The Interconnection Customer shall provide a letter of credit from a reasonably acceptable provider, or other form of reasonably acceptable security that names either the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or the Interconnected Transmission Owner as applicable, as the beneficiary in an amount equal to the ENUC (the "Security"). The Interconnection Customer shall have the option to provide the Security to either the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or the Interconnected Transmission Owner and shall notify all Parties of its election within ten (10) days of receipt of the NUFA from the Transmission Provider. The entity whom the Interconnection Customer chooses to provide with the Security, either the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or the Interconnected Transmission Owner, shall determine whether the letter of credit or other form of security is reasonably acceptable. The Security shall be provided to Transmission Provider or Interconnected Transmission Owner, as applicable, by Interconnection Customer pursuant to this Section 4.1 within the later of: (i) forty-five (45) days of the execution of this NUFA by all Parties; (ii) forty-five (45) days of acceptance of this NUFA by FERC if this NUFA is filed unexecuted and the Security is being protested by Interconnection Customer; or (iii) forty-five (45) days of the date of filing of this NUFA if it is filed unexecuted and the Security is not being protested by Interconnection Customer. To the extent that the Interconnection Customer has provided Security under the ISA for any portion of the Network Upgrades covered by the NUFA, the Security required under this NUFA shall be reduced by the amount of Security required under the ISA for such Network Upgrades. Prior to the release of the Security under the ISA for the Network Upgrades by the Transmission Provider, the Interconnection Customer shall provide additional Security to the Interconnected Transmission Owner or Transmission Provider, as applicable, under this NUFA in an amount that is equal to the amount of Security for the Network Upgrades released under the ISA. The Security provided under the ISA may be applied to satisfy the Security requirements under the NUFA if the form, terms, and provider of the Security provided under the ISA allow it. In no event shall Interconnection Customer allow Security to lapse between the ISA and this NUFA. The Interconnection Customer must maintain the Security required under this NUFA or the ISA at all times. Likewise, in no event shall Interconnection Customer be required to maintain concurrently the full amount of Security under the ISA and the full amount of Security under this NUFA. The Security may be adjusted to an amount equal to the ANUC after such time that the one-time true-up adjustment as described in Section 3.7 is completed for each Network Upgrade. The Security shall remain with Transmission Provider or Interconnected Transmission Owner, as applicable, for the remaining months of the Term. At Interconnection Customer's discretion, such Security may be reduced by five percent (5%) (or a prorated portion based on the Term of this NUFA, as agreed by the Parties) of the ANUC of each Network Upgrade on the first anniversary of the In-Service Date of that Network Upgrade and may continue to be reduced by five percent (5%) (or a prorated portion based on the Term of this NUFA, as agreed by the Parties) each year over the Term of this NUFA, provided that any such reduction in the amount of Security must be evidenced to either the Transmission Provider or the Interconnected Transmission Owner, as applicable, in the form of a revised form of Security reasonably acceptable to the Interconnected Transmission Owner.

4.2 Draws on Security. In the event Interconnection Customer fails to make a payment by the Monthly Due Date or Annual Due Date, as applicable, Transmission Provider or Interconnected Transmission Owner, as applicable, shall be entitled to draw on the Security posted by Interconnection Customer in the amount of the missed Payments as well as any accrued interest charges based on the Commission's regulations at 18 C.F.R § 35.19a. If Interconnection Customer fails to make payment by the Monthly Due Date or Annual Due Date, as applicable, and Security has been depleted, Interconnection Customer shall provide to the Transmission Provider (for the benefit of the Interconnected Transmission Owner) or Interconnected Transmission Owner, as applicable based on the election in Section 4.1 new irrevocable security, in a form reasonably acceptable ("New Security") within thirty (30) days of the holder's demand for New Security.

4.3 Security Requirements. Security shall remain in place until expiration of this NUFA. Any Security provided by Interconnection Customer must be kept active, must continue to meet the security requirements of the Interconnected Transmission Owner or the Transmission Provider, as applicable, and must be available to Transmission Provider or Interconnected Transmission Owner, as applicable, for the purpose of making payments under this NUFA in the event that Interconnection Customer fails to make such payment. Any fees or costs associated with the provision of security are the responsibility of the Interconnection Customer.

4.4 Tax Gross-Up. Interconnection Customer acknowledges that the construction of the Network Upgrade(s) under the ISA could be subject to tax gross-up, as applicable, upon the Interconnection Customer's default under this NUFA and that the Security provided hereunder could be used to cover such obligations.

5. Breach, Default, and Cross-Default

5.1 General. Upon a Breach of this NUFA, the non-breaching Party or Parties shall give written notice of such Breach to the Breaching Party with a copy to all non-breaching Parties. The Breaching Party shall have thirty (30) days from receipt of the notice of Breach within which to cure such Breach; provided, however, if such Breach is not capable of cure within thirty (30) days, the Breaching Party shall commence such cure within thirty (30) days after notice thereof and shall continuously and diligently complete such cure within ninety (90) days from receipt of the notice of Breach. If cured within such time provided by the foregoing, the Breach specified in such notice shall be deemed cured and treated by the Parties as if it had not occurred. If a Breach is not cured as provided in this Section 5.1, or is not capable of being cured within the period provided for herein, the Breaching Party shall be in default under this NUFA.

5.2 Interconnection Customer Default. Interconnection Customer shall be in default of this NUFA if Interconnection Customer: (i) fails to make two (2) consecutive monthly Payments when due or be more than sixty (60) days late in providing an annual payment; provided that, Transmission Provider has given Interconnection Customer notice of and Interconnection Customer has failed to cure such late payments consistent with Section 5.1; (ii) fails to provide New Security within thirty (30) days of the demand for New Security consistent with Section 4.2; (iii) terminates operation of its Customer Facility prior to the end of the Term of this NUFA; or (iv) is declared to be in Default under its ISA. In the event of default, Interconnection Customer shall promptly pay to Transmission Provider all Payments still owed under this NUFA. In the event that Interconnection Customer does not promptly pay all amounts due and owing to the Transmission Provider, the Transmission Provider may draw on the remaining balance of the Security provided by the Interconnection Customer. This payment or draw on the Security does not limit any and all rights and remedies available to the Transmission Provider or Interconnected Transmission Owner allowed by law with respect to such default or collecting all amounts owed for the remaining months due under this NUFA. Interconnection Customer shall indemnify Transmission Provider and Interconnected Transmission Owner for reasonable costs, attorney fees and/or expenses incurred with respect to a default or collecting all amounts owed for the remaining months, including, as applicable, any tax gross-up obligations under this NUFA.

5.3 Interconnected Transmission Owner Default. Interconnected Transmission Owner shall be in default of this NUFA if Interconnection Transmission Owner: (i) fails to provide Interconnection Customer with any of the information access and audit rights provided in Section 3.6; (ii) such failure is not cured following notice from Interconnection Customer as provided in Section 5.1; and (iii) such failure has a material adverse effect on Interconnection Customer's ability to perform under this NUFA.

5.4 Cross-Default. This NUFA is a requirement for Interconnection Service under the PJM Tariff when an Interconnected Transmission Owner has elected to fund the capital for the Network Upgrades and shall be subject to the terms and conditions of the PJM Tariff, including the rights to termination of Interconnection Service. Notwithstanding anything to the contrary contained in this NUFA, a Breach by Interconnection Customer of any provision, covenant or other term or condition contained in this NUFA shall be considered a Breach under the Interconnection Customer's ISA referenced in the recitals to this NUFA. An event of default by Interconnection Customer under Section 5.2 hereof shall, after the passage of all applicable notice and cure or grace periods, be considered a default under this NUFA and a default of the Interconnection Customer's ISA referenced in the recitals to this NUFA. Interconnected Transmission Owner and Transmission Provider shall be entitled (but in no event required) in an event of such dual Breach or default to apply all rights and remedies available in this NUFA and the ISA by reason of a Breach or default.

5.5 Notice of Default. In the event of a default under Interconnection Customer's ISA, Transmission Provider shall provide prompt notice of such default to all affected Transmission Owners that have FERC-filed service agreements with Interconnection Customer under the PJM Tariff.

6. **Reimbursed Network Upgrades**

Following the execution of this NUFA, if the Transmission Provider determines that any portion of the costs of the Network Upgrades covered by this NUFA should be allocated to one or more subsequent Customer Facilities ("New Customer(s)"), the Parties shall amend this NUFA and/or enter into new agreements in the form provided in Tariff, Attachment O-2 to reflect Interconnection Customer and New Customer's (or New Customers') respective responsibility for the remaining costs of the Network Upgrade subject to this NUFA based on the effective date of New Customer's ISA.

7. **Assignment**

This NUFA shall inure to the benefit of and be binding upon each Party's successors and permitted assigns. No Party shall assign this NUFA or their related contractual rights without the prior written consent of the other Parties, which prior written consents shall be not be unreasonably withheld or delayed; provided that the assignee is at least as creditworthy as the assigning Party and the assignee of the Interconnection Customer shall provide Interconnected Transmission Owner with Security as contemplated herein; and provided further that Interconnection Customer shall have the right to assign this NUFA, without the consent of either the Transmission Provider or the Interconnected Transmission Owner, for collateral security purposes to aid in providing financing for the Customer Facility, provided that Interconnection Customer will promptly notify Transmission Provider and Interconnected Transmission Owner of any such assignment. No assignment of this NUFA shall release or discharge any Party from their future obligations hereunder unless all such obligations are assumed by the successor or assignee of that Party in writing.

8. **No Transmission Service**

The execution of a NUFA does not constitute a request for transmission service, or entitle Interconnection Customer to receive transmission service, under Tariff, Part II or Tariff, Part III. Nor does the execution of an NUFA obligate Interconnected Transmission Owner or Transmission Provider to procure, supply or deliver to Interconnection Customer or the Customer Facility any energy, capacity, Ancillary Services or Station Power (and any associated distribution services).

9. **Miscellaneous**

9.1 Entire Agreement. This NUFA represents the entire agreement among the Parties with reference to payment terms for the Network Upgrade(s) provided by Interconnected Transmission Owner for Interconnection Customer under the ISA. This NUFA may not be amended, modified, or waived other than by a written document signed by all Parties.

9.2 Confidentiality

9.2.1 Definition. Confidential Information under this NUFA shall have the same meaning as provided in the PJM Tariff. Critical Energy/Electric Infrastructure Information ("CEII") shall have the meaning provided in 18 C.F.R. § 388.113(c)(1)-(2).

9.2.2 Term. During the Term of this NUFA, and for a period of three (3) years after the expiration or termination of the NUFA, except as otherwise provided in this Section 9.2 or with regard to CEII, each Party shall hold in confidence, and shall not disclose to any person, Confidential Information provided to it by any other Party. In addition to being treated as Confidential Information hereunder, CEII shall be treated in accordance with Commission policy and regulations.

9.2.3 Scope. Confidential Information shall not include information that the receiving Party can demonstrate: (i) is generally available to the public other than as a result of a disclosure by the receiving Party; (ii) was in the lawful possession of the receiving Party on a non-confidential basis before receiving it from the disclosing Party; (iii) was supplied to the receiving Party without restriction by a third party, who, to the knowledge of the receiving Party, after due inquiry, was under no obligation to the disclosing Party to keep such information confidential; (iv) was independently developed by the receiving Party without reference to Confidential Information of the disclosing Party; (v) is, or becomes, publicly known, through no wrongful act or omission of the receiving Party or Breach of this NUFA; or (vi) is required, in accordance with Section 9.2.8, to be disclosed to any Governmental Authority or is otherwise required to be disclosed by law or subpoena, or is necessary in any legal proceeding establishing rights and obligations under this NUFA. Information designated as Confidential Information shall no longer be deemed confidential if the Party that designated the information as confidential notifies the other Parties that it no longer is confidential.

9.2.4 Release of Confidential Information. No Party shall disclose Confidential Information to any other person, except to its Affiliates (limited by the Commission's Standards of Conduct for Transmission Providers, 18 C.F.R. Part 358), subcontractors, employees, agents, consultants, or to non-parties who may be or are considering providing financing to or equity participation with Interconnection Customer, or to potential purchasers or assignees of Interconnection Customer, on a need-to-know basis in connection with this NUFA, unless such person has first been advised of the confidentiality provisions of this Section 9.2 and has agreed to comply with such provisions. Notwithstanding the foregoing, a Party providing Confidential Information to any person shall remain primarily responsible for any release of Confidential Information in contravention of this Section 9.2.

9.2.5 Rights. Each Party retains all rights, title, and interest in the Confidential Information that it discloses to any other Party. The disclosure by a Party to the receiving Party of Confidential Information shall not be deemed a waiver by the disclosing Party or any other person or entity of the right to protect the Confidential Information from public disclosure. Nothing in this NUFA shall limit or otherwise modify Transmission Provider's rights and obligations with respect to Confidential Information as set forth in the PJM Tariff.

9.2.6 No Warranties. By providing Confidential Information, no Party makes any warranties or representations as to its accuracy or completeness. In addition, by supplying Confidential Information, no Party obligates itself to provide any particular information or Confidential Information to another Party nor to enter into any further agreements or proceed with any other relationship or joint venture.

9.2.7 Standard of Care. Each Party shall use at least the same standard of care to protect Confidential Information it receives as it uses to protect its own Confidential Information from unauthorized disclosure, publication or dissemination. Each Party may use Confidential Information solely to fulfill its obligations to another Party under this NUFA or its regulatory requirements.

9.2.8 Order of Disclosure. If a Governmental Authority with the right, power, and apparent authority to do so requests or requires any Party, by subpoena, oral deposition, interrogatories, requests for production of documents, administrative order, or otherwise, to disclose Confidential Information, that Party shall provide the disclosing Party with prompt notice of such request(s) or requirement(s) so that the disclosing Party may seek an appropriate protective order or waive compliance with the terms of this NUFA. Notwithstanding the absence of a protective order or waiver, the Party may disclose such Confidential Information which, in the opinion of its counsel, the Party is legally compelled to disclose. Each Party will use Reasonable Efforts to obtain reliable assurance that confidential treatment will be accorded any Confidential Information so furnished.

9.2.9 Termination of Agreement. Upon termination of this NUFA for any reason, each Party shall, within ten (10) days of receipt of a written request from another Party, use Reasonable Efforts to destroy, erase, or delete (with such destruction, erasure, and deletion certified in writing to the requesting Party) or return to the requesting Party, without retaining copies thereof, any and all written or electronic Confidential Information received from the requesting Party.

9.2.10 Remedies. The Parties agree that monetary damages would be inadequate to compensate a Party for another Party's breach of its obligations under this Section 9.2. Each Party accordingly agrees that the disclosing Party shall be entitled to equitable relief, by way of injunction or otherwise, if the receiving Party breaches or threatens to breach its obligations under this Section 9.2, which equitable relief shall be granted without bond or proof of damages, and the breaching Party shall not plead in defense that there would be an adequate remedy at law. Such remedy shall not be deemed an exclusive remedy for the breach of this Section 9.2, but shall be in addition to all other remedies available at law or in equity. The Parties further acknowledge and agree that the covenants contained herein are necessary for the protection of legitimate business interests and are reasonable in scope. No Party, however, shall be liable for indirect, incidental, or consequential or punitive damages of any nature or kind resulting from or arising in connection with this Section 9.2.

9.2.11 Disclosure to FERC or its Staff. Notwithstanding anything in this Section 9.2 to the contrary, and pursuant to 18 C.F.R. § 1b.20, if FERC or its staff, during the course of an investigation or otherwise, requests information from a Party that is otherwise required to be maintained in confidence pursuant to this NUFA, the Party shall provide the requested information to FERC or its staff, within the time provided for in the request for information. In providing the information to FERC or its staff, the Party must, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this NUFA prior to the release of the Confidential Information to FERC or its staff. The Party shall notify the other Parties to this NUFA when it is notified by FERC or its staff that a request to release Confidential Information has been received by FERC, at which time any of the Parties may respond before such information would be made public, pursuant to 18 C.F.R. § 388.112.

9.2.12 Competitively Sensitive Information. Subject to the exception in Section 9.2.11, any information that a disclosing Party claims is competitively sensitive, commercial or financial information under this NUFA shall not be disclosed by the receiving Party to any person not employed or retained by the receiving Party, except to the extent disclosure is (i) required by law; (ii) reasonably deemed by the receiving Party to be required to be disclosed in connection with a dispute between or among the Parties, or the defense of litigation or dispute; (iii) otherwise permitted by consent of the disclosing Party, such consent not to be unreasonably withheld; or (iv) necessary to fulfill its obligations under this NUFA or as the Regional Transmission Organization including disclosing the Confidential Information to a regional or national reliability organization. The Party asserting confidentiality shall notify the receiving Party in writing of the information that Party claims is confidential. Prior to any disclosures of that Party's Confidential Information under this Section 9.2.12, or if any non-Party or Governmental Authority makes any request or demand for any of the information described in this subparagraph, the Party who received the Confidential Information from the disclosing Party agrees to promptly notify the disclosing Party in writing and agrees to assert confidentiality and cooperate with the disclosing Party in seeking to protect the Confidential Information from public disclosure by confidentiality agreement, protective order or other reasonable measures.

9.3 Regulatory Approval. This NUFA and its terms shall be subject to approval, if applicable, by the Commission. This NUFA and its terms shall also be subject to, as applicable, the PJM Tariff.

9.4 Force Majeure.

9.4.1 Notice. A Party that is unable to carry out an obligation imposed on it by this NUFA due to Force Majeure shall notify the other parties in writing or by telephone within a reasonable time after the occurrence of the cause relied on.

9.4.2 Duration of Force Majeure. A Party shall not be responsible, or considered to be in Breach or default under this NUFA, for any failure to perform any obligation hereunder to the extent that such failure or deficiency is due to Force Majeure. A Party shall be excused from whatever performance is affected only for the duration of the Force Majeure and while the Party exercises Reasonable Efforts to alleviate such situation. As soon as the non-performing Party is able to resume performance of its obligations excused because of the occurrence of Force Majeure, such Party shall resume performance and give prompt notice thereof to the other parties.

9.4.3 Obligation to Make Payments. Any Party's obligation to make payments for services shall not be suspended by Force Majeure.

9.4.4 Definition of Force Majeure. For purposes of this section, an event of Force Majeure shall mean any cause beyond the control of the affected Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which, in any of the foregoing cases, by exercise of due diligence such Party could not reasonably have been expected to avoid, and which, by the exercise of due diligence, it has been unable to overcome. Force Majeure does not include (i) a failure of performance that is due to an affected Party's own negligence or intentional wrongdoing; (ii) any removable or remediable causes (other than settlement of a strike or labor dispute) which an affected Party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected Party.

9.5 Disputes. Any dispute hereunder shall be referred to senior representatives of each Party. If the senior representatives are not able to resolve the dispute within thirty (30) days, the dispute resolution procedures of Tariff, Part I section 12 and Tariff, Part IV, section 40 shall apply to the resolution of any dispute hereunder.

9.6 Reservation of Rights. Nothing in this NUFA shall limit the rights of the Parties or of FERC under Section 205 and 206 of the Federal Power Act and FERC's rules and regulations thereunder.

9.7 Liability. A party shall not be liable to another Party or to any third party or other person for any damages arising out of actions under this NUFA, including, but not limited to, any act or omission that results in an interruption, deficiency or imperfection of Interconnection Service, except as provided in the PJM Tariff. The provisions set forth in the PJM Tariff shall be additionally applicable to any Party acting in good faith to implement or comply with its obligations under this NUFA, regardless of whether the obligation is preceded by a specific directive.

9.8 Governing Law. This NUFA is governed by and shall be construed in accordance with laws of the State of Delaware, without regard for any principles of conflicts of laws.

9.9 No Waiver. It is mutually understood that any failure by Transmission Provider or Interconnected Transmission Owner or inconsistency to enforce or require the strict keeping and performance by Interconnection Customer of any of the provisions of this NUFA shall not constitute a waiver by Transmission Provider or Interconnected Transmission Owner of such provisions, and shall not affect or impair such provisions in any way, or the right of Transmission Provider or Interconnected Transmission Owner at any time to avail itself of such remedies as it may have for any breach or breaches of such provisions. The waiver, illegality, invalidity and/or unenforceability of any provision appearing in this NUFA shall not affect the validity of this NUFA as a whole or the validity or any other provisions therein.

9.10 Waiver of Jury Trial. TO THE FULLEST EXTENT PERMITTED BY LAW, EACH OF THE PARTIES HERETO WAIVES ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF LITIGATION DIRECTLY OR INDIRECTLY ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS NUFA. EACH PARTY FURTHER WAIVES ANY RIGHT TO CONSOLIDATE ANY ACTION IN WHICH A JURY TRIAL HAS BEEN WAIVED WITH ANY OTHER ACTION IN WHICH A JURY TRIAL CANNOT BE OR HAS NOT BEEN WAIVED.

10. **Notice**

10.1 General. Any notice, demand or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another may be so given, tendered or delivered, by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address specified in Section 10.2. Such notices, if agreed to by the Parties, may be made via electronic means, with e-mail confirmation of delivery.

10.2 Contacts. Any Party may update its contact information by providing notice to the other Parties in accordance with Section 10.1.

Interconnected Transmission Owner
[Name]
[Company or Organization]

[Business Address]
[City, State Zip]
[Email]

Interconnection Customer
[Name]
[Company or Organization]

[Business Address]
[City, State Zip]
[Email]

Transmission Provider
[Name]
PJM Interconnection, L.L.C.

2750 Monroe Blvd
Audubon, PA 19403
[Email]

SIGNATURE PAGE FOLLOWS

IN WITNESS WHEREOF, Transmission Provider, Interconnection Customer and Interconnected Transmission Owner have caused this NUFA to be executed by their respective authorized officials.

(PJM Queue Position #___)

Transmission Provider: **PJM Interconnection, L.L.C.**

____

By: ____________________ ____________________ ______________
Printed Name Title Date

Interconnection Customer: **[Name of Party]**

____

By: ____________________ ____________________ ______________
Printed Name Title Date

Interconnected Transmission Owner:

____

By: ____________________ ____________________ ______________
Printed Name Title Date

Schedule A

Network Upgrade Facilities

Schedule B

Formula Rate Exhibit

PJM TO @ 21% FIT
Schedule B

Levelized Fixed Charge Rate Calculation with Deferred Recovery (Blank Template)

Line			
1			
2			
3			
4			
5			
6			
7	Project Name:	20XX Network Upgrade project	
8			
9	Description	20XX Network Upgrade project	
10			
11	Cost Year:	20XX Actual True-up	
12			
13	Estimated or Actual Cost and ISD:	Actual cost; Actual ISD 6/1/20XX	
14			
15	Rate Recovery Period:	June 1, 20XX thru May 31, 20XX	
16			
17	Levelized Fixed Charge Computation:		
18			
19	Initial Network Upgrade Capital Cost		$0
20	Levelized FCR with Deferred Recovery	(Line 57)	0.0000%
21	Annual Network Upgrade Charge	(Line 19 x Line 20)	$0
22	Monthly Payment	(Line 21 / 12)	$0
23			
24	Fixed Charge Rate Calculation:		
25			
26	Investment	(Line 19)	0
27			
28	PW Federal Tax Depreciation	[Line 109, Col (f)]	0
29	Applicable federal tax rate	(Line 64)	0.00%
30	PW Federal Tax Benefit	(Line 28 x Line 29)	0
31			
32	PW State Tax Depreciation	[Line 109, Col (g)]	0
33	Applicable state tax rate	(Line 65)	0.00%
34	PW State Tax Benefit	(Line 32 x Line 33)	0
35			
36	PW Tax Benefit	(Line 30 + Line 34)	0
37	Present Worth Cashflow	(Line 26 - Line 36)	0
38	Revenue Conversion Factor	[1/(1 - Line 63)]	1.0000

39	Present Worth Revenue Requirement	(Line 37 x Line 38)	0
40			
41	In Service Date		6/1/2021
42	Recovery Start Date		6/1/2021
43	Deferral Days (February counted as 28 days)		0
44	Deferral Annualization Factor (based on 365 days)	(Line 43/365)	0.0000%
45	Discount Rate per Year	(Line 75)	0.0000%
46	Deferral Factor	{[(1+Line 45)^Line 44] - 1}	0.0000%
47	Deferral Adjustment	(Line 39 x Line 46)	0
48			
49	Present Worth with Deferred Recovery	(Line 39 + Line 47)	0
50			
51	Recovery Period (RP)		20
52	Annualization Factor	{ i [(1+i)^RP]} / {[(1+i)^RP] -1}	0.0000%
53		(where RP is Line 51, and i is Line 45)	
54			
55	Levelized Amount	(Line 49 x Line 52)	0
56			
57	Levelized Fixed Charge Rate (FCR)	(Line 55 / Line 26)	0.0000%
58			
59			
60	Project Name:	20XX Network Upgrade project	
61			

62	Inputs from Formula Rate True-up Filing	
63	Combined Tax Rate	0.00%
64	Applicable Federal Income Tax Rate	0.00%
65	Applicable State Income Tax Rate	0.00%
66		
67		

68	Capital Structure	Amount	Weight	Cost	Weighted Cost
69					
70	Long-Term Debt	0	0.00%	0.00%	0.0000%
71	Preferred Stock	0	0.00%	0.00%	0.0000%
72	Common Equity	0	0.00%	0.00%	0.0000%
73	Total Capitalization	0	0.00%		0.0000%

74

75 Discount Rate (Line 73 - (Line 63 x Line 70)) 0.0000%

76

77

78

79

80 MACRS Depreciation Rates with Bonus Depreciation Option:

81

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)
82	(a)	(b)	(c)	(d)	(e)	(f)	(g)
83	Year	MACRS	MACRS	State	Present	Present	Present
84		Rates	Depr	Depr	Worth	Worth	Worth
85					Factor	Federal Tax	State Tax
86					1/(1+i)^n	Depreciation	Depreciation
87							
88	Base	(Line 19)	$0	$0			
89	1	0.00%	0		1.000000	0	
90	Remaining Base	(Line 88-Line 89)	0.0				
91							
92	1	5.00%	0	0	1.000000	0	0
93	2	9.50%	0	0	1.000000	0	0
94	3	8.55%	0	0	1.000000	0	0
95	4	7.70%	0	0	1.000000	0	0
96	5	6.93%	0	0	1.000000	0	0
97	6	6.23%	0	0	1.000000	0	0
98	7	5.90%	0	0	1.000000	0	0
99	8	5.90%	0	0	1.000000	0	0
100	9	5.91%	0	0	1.000000	0	0
101	10	5.90%	0	0	1.000000	0	0
102	11	5.91%	0	0	1.000000	0	0
103	12	5.90%	0	0	1.000000	0	0
104	13	5.91%	0	0	1.000000	0	0
105	14	5.90%	0	0	1.000000	0	0
106	15	5.91%	0	0	1.000000	0	0
107	16	2.95%	0	0	1.000000	0	0
108							
109		Total	0	0		0	0
110							

111 Footnote:

112 *Use Line 89 if bonus depreciation is applicable*

113

Return \ Capitalization Calculations From Transmission Formula Rate True-up Filing

Line or Note					Response	Cap Limit %
	Does the formula rate template include a Capital Structure Equity Limit (Cap)? (Yes or No)				No	

		$	Actual %	Cap Limit %	Cost (Note "X")	Weighted	
	Long Term Debt	0	0.00%	0.00%	0.0000	0.0000	=WCLTD
	Preferred Stock	0	0.00%	0.00%	0.0000	0.0000	
	Common Stock	0	0.00%	0.00%	0.0000	0.0000	
	Total Capitalization (Sum Lines to)	0				0.0000	=R

Income Tax Rates From Transmission Formula Rate True-up Filing

	FIT =	0.00%
	SIT=	0.00%
	p =	0.00%

INCOME TAXES

T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} = 0.00%

Notes:

ATTACHMENT C

Affidavit of David W. Weaver, P.E.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Transmission Owners	))))))	**Docket No. ER21-_____**

AFFIDAVIT OF DAVID W. WEAVER, P.E.

I. Introduction

1. My name is David W. Weaver. I am Vice President of Transmission Strategy at Exelon. I oversee the company's transmission strategy organization, with responsibility for transmission infrastructure investment, policy, interconnection contracts, planning, and strategy across all the Exelon Operating Companies.
2. I began my career with Exelon in June of 1989, starting with the then individual operating company Delmarva Power. Next, I transitioned to PECO Energy Company ("PECO"), which later consolidated with Commonwealth Edison Company as Exelon. As an officer of PECO overseeing Technical Services, I had responsibility for distribution standards, capacity planning, project/contract/vegetation management, reliability programs, and capital budget. I have served in various roles throughout my career in engineering, transmission operations, transmission planning, project management, and business planning. With over 30 years of experience in the utility industry, predominantly in transmission planning and operations, I previously served as chair of the North American Electric Reliability Corporation ("NERC") Planning

Committee and currently serve as the President of WIRES, a non-profit trade association that promotes investment in the electric transmission system.

3. I am submitting this Affidavit in support of the PJM Transmission Owner's June 30, 2021 filing. In this Affidavit, I present evidence that the PJM Transmission Owners face real and significant risks as a result of their obligation to own and operate Network Upgrades needed to accommodate the interconnection of new generation resources (referred to herein as Network Upgrades). My testimony further describes these risks and provides examples of potential liabilities resulting from owning and operating Network Upgrades.

II. The PJM Transmission Owners Are Not Compensated for Assuming the Risks Associated with Owning and Operating Network Upgrades

4. As explained throughout this Affidavit, transmission owners have an obligation to build, own, operate, and maintain Network Upgrades, but because these upgrades are funded by the interconnection customer, transmission owners have no opportunity to earn a rate of return under the Existing Funding Model in PJM. In PJM, Transmission Owners are permitted to recover the costs of operating and maintaining Network Upgrades, but because these costs are not capital expenditures, the PJM Transmission Owners do not earn any return on them. As such, they receive no compensation for assuming the risks described below with respect to Network Upgrades and provide no compensation to shareholders for owning and operating those facilities. Any risks that are realized thus impose costs on the PJM Transmission Owners' shareholders, without corresponding compensation.

Essentially, transmission owners are being asked to deliver electricity from new generation resources at cost; this is akin to paying a pizza delivery person for gas and the wear and tear on their vehicle, but not providing any compensation for their time or the value of the service that they provide.

III. Risks Associated with Owning and Operating Network Upgrades

5. Transmission owners bear significant risks associated with installing, owning, and operating Network Upgrades. While those risks have been present since PJM implemented its current approach to funding network upgrades, they are increasing in magnitude as more and more generators interconnect to the PJM system. In fact, given that the current PJM transmission system has limited unused transmission capacity, Network Upgrades are required to accommodate many new generator interconnection requests in PJM. As such, these risks have a growing impact on the PJM Transmission Owners' core business model, undermining the regulatory compact under which they provide safe and reliable transmission service to their customers and have done so for almost a century.
6. As required by the existing regulatory structure, transmission owners operate their transmission systems and recover from customers the prudent costs for doing so. To compensate transmission owner shareholders for their investment in the transmission owner, the transmission owner also receives a return on its capital investments. The return provides compensation to the transmission owner's shareholders for the ongoing risks associated with owning and operating their transmission assets over the course of these assets' useful lives. Under PJM's Existing Funding Model for

funding Network Upgrades, however, the PJM Transmission Owners do not have the opportunity to fund and earn a return on capital investments in generator interconnection network upgrades -- upgrades that are as much a part of their transmission systems as any other transmission facility. As a result, the PJM Transmission Owners earn no profit on those assets and more importantly, no compensation for the risks of owning and operating them.

7. In this Affidavit, I explain many of the uncompensated risks that the PJM Transmission Owners face from installing, owning, and operating Network Upgrades. As a general matter, these risks can be broken down into the following categories:

- <u>Operational and Safety Risks</u>: These risks stem from the inherent safety hazards involved in both the installation and day-to-day operations of high-voltage transmission equipment, as well as the added complexities and risks of running a transmission system when an element of that system is on outage. They are particularly apparent in the context of emergency response, with which I have ample experience.
- <u>Reliability and Cybersecurity Compliance Risks</u>: Any additions to the transmission system increase its complexity, and Network Upgrades are no exception. As the owners and operators of the system, transmission owners experience increased exposure to outages, blackouts, cybersecurity, and other reliability and NERC compliance issues as the complexity of the system for which they are responsible expands, imposing additional risk.
- <u>Environmental Risks</u>: Installing, owning, and operating Network Upgrades exposes transmission owners to liabilities associated with the environmental issues that certain

transmission equipment can cause, such as soil and/or ground water contamination, as well as preexisting contamination at sites at which transmission equipment is located.

- Weather and Climate Risks: Severe weather events and changing climate and weather patterns can damage or destroy transmission equipment (including Network Upgrades), creating potential risks and liabilities for a transmission owner.
- Outage Coordination Risks: Installing and integrating Network Upgrades into a transmission owner's existing system often requires outages of existing transmission equipment. These outages are difficult to coordinate; the transmission owner must ensure that they do not interfere with the reliable provision of service or other planned outages. Any breakdown in coordination could lead to customer outages, damaging the transmission owner's reputation and potentially resulting in litigation.

8. I discuss each separate category of risks and their implications for the PJM Transmission Owners in greater detail in the subsequent sections. In many cases, these risks stem not only from a transmission owner's ongoing obligation to own and operate Network Upgrades, but also from the transmission owner's obligation to build the upgrades in the first place. While the Commission has a policy of allowing interconnection customers the option to build certain Network Upgrades, a customer's decision to build the upgrades does not reduce the risks to the transmission owner. In fact, as described in several examples below, if an interconnection customer avails itself of the option to build, that decision can impose new and different risks on the transmission owner (risks over which it has little control and that are thus especially difficult to mitigate). And if an interconnection

customer is ultimately unable to finish construction, the transmission owner may have an obligation to complete the upgrades on the customer's behalf.

9. Importantly, where the transmission owner is responsible for constructing the Network Upgrade, the risks described throughout this Affidavit are similar regardless of whether the Network Upgrade is a greenfield transmission line or an upgrade to an existing transmission facility. Many of the risks described herein are associated with owning and operating Network Upgrades and thus apply equally to all types of Network Upgrades because the transmission owner experiences them only after the Network Upgrade is complete. For those risks associated with constructing Network Upgrades, the risks will be different for each individual project, and upgrades to existing transmission assets, though often less impactful to customers, are not necessarily less risky than greenfield projects. For example, upgrades of existing transmission assets still require local permitting, and an upgrade to an existing transmission line that traverses an environmentally sensitive area would likely be a riskier project than a short greenfield line co-located with existing infrastructure (e.g., a transportation corridor) in an industrialized area.

10. Finally, many of these risk categories are interrelated, and realization of one type of risk could create exposure to additional risks. For example, if a weather risk is realized when a severe storm damages a transformer, a transmission owner might experience increased safety risks for the personnel responsible for repairing the damage or environmental risks associated with the potential for an inadvertent oil spill. All of the risks discussed above have similar implications for the PJM Transmission Owners. If the risks are realized, it could result in: (1) penalties or

fines that the transmission owner will not be able to recover through rates, (2) reputational harm that may not be repairable and will have an impact on the transmission owner's business and relationship with its customers, and (3) a need to dedicate significant time and resources to litigation rather than more productive business activities.

A. Operational and Safety Risks

11. The core of each transmission owner's business is to install, own, operate, and maintain its transmission assets in accordance with good utility practice so that it can fulfill its obligation to provide reasonably priced, safe, and reliable service to its customers (including the generators interconnected to its system). However, fulfilling its obligation to provide this critical service is not without risks; it is imperative that transmission owners protect the safety of employees, contractors, and the public when installing, operating, and maintaining their transmission assets. Transmission owners must also monitor their systems continuously, ensuring that operational issues do not turn into customer outages. These operational and safety risks are part of each transmission owner's routine operations and maintenance of its transmission system but are most apparent when a transmission owner is responding to an emergency related to its equipment. For this reason, I discuss these risks in the context of emergency response in this Affidavit.

12. Having served in numerous Exelon emergency response leadership roles throughout my career, I have first-hand knowledge of the operational and safety risks that installing, owning, and operating transmission assets imposes on transmission owners. These roles include my current role as Exelon Utilities Incident Duty

Officer, as well as my previous roles at PECO as System Incident Commander, Transmission & Substation Emergency Response Manager, and Transmission System Operation Emergency Response Manager. My experience has provided me with keen insights into the emergent risks associated with reliably and safely operating transmission infrastructure. Here, I describe a few examples of the types of emergency issues of which I am aware and the operational and safety risks that they create. I also explain how realization of these operational and safety risks can generate additional risks, such as environmental risks.

13. Throughout my career, I have witnessed a number of emergencies associated with transformer fires at substations due to equipment failure. Such emergencies require an all-hands-on-deck approach to safely restore service to customers. While Exelon, like most transmission owners, maintains sufficient spare transformers to replace failed or damaged equipment, the logistics of transporting these spares to the required destination are complex. For example, to replace a damaged transformer, our crews must first drain and undress a spare transformer so that it can be transported to the site. Transportation of the replacement transformer can take weeks depending on the substation location and requires significant coordination with local/state authorities to ensure the safety of the general public while in-route. We must use trains and barges to transport the replacement transformers for substations where there is no feasible route over roads, which adds an additional level of complexity. Once on-site, the spare transformer must be dressed and refilled with oil. It could be up to two weeks before the spare transformer is ready for service. Moreover, our crews must perform

the same process of draining and undressing the damaged transformer to remove it from the pad and transport it from the site.

14. There are significant safety risks associated with this emergency response effort. Responding to a transformer fire is inherently dangerous, and the danger does not end when the fire is extinguished. There have been cases where a bushing failure that resulted in the transformer fire or a bushing damaged from the fire has caused sharp pieces of porcelain to get thrown throughout the yard, posing a hazard to anyone on the property. Exelon's top priority is to make the work environment as safe as possible for its employees, but accidents can and do occur when dealing with such a dangerous product, particularly in emergency situations where the transmission owner must rapidly respond to an immediate safety threat. If an injury from such an event were to occur, Exelon could be exposed to lawsuits and regulatory penalties that would not be recoverable through transmission rates.

15. There are also safety risks associated with undressing and draining both the spare and damaged transformers given the hazardous substances involved. Ancillary to these safety risks are environmental risks; the process of draining oil from the spare and damaged transformer and refilling the spare transformer requires careful management to avoid oil spills and any resulting soil and/or ground water contamination. Many times, the damaged transformer will be compromised and will leak oil as a result. This potential for oil leaks also exposes Exelon, and other transmission owners, to potential litigation and regulatory penalties over any resulting environmental

damages. Again, depending on the situation, these costs may not be recoverable in transmission rates.

16. There are numerous reasons that transmission equipment can be damaged for reasons outside of the transmission owner's control. For example, during my career, I have encountered many different ways that foreign objects can interfere with overhead transmission lines. Such interference can occur during storms (when a tree falls on a line, for example), but it can also occur unexpectedly as the result of daily human activities (e.g., tarps from construction job sites can blow into lines, mylar balloons can drift into lines, the mast of a sailboat that has broken free from its moorings can fault a line, or a blimp can break free from its mooring and its mooring chains can trip lines). Even more remote events occur from time to time; I am aware of an incident at one of the Exelon Utilities where a dump truck drove through a 230 kV double circuit lattice tower with its bed up and destroyed the tower and another where a fighter jet crashed adjacent to a 230 kV right-of-way and the pilot's ejector seat nicked a 230 kV phase on the way down. Again, to the extent that any accidents occur, Exelon could potentially be liable, presenting the risk of litigation and penalties that are not recoverable through transmission rates.

17. When any piece of transmission equipment is damaged or fails, there are operational risks involved with operating the system without it. While the damaged or failed equipment is out of service, the transmission owner must temporarily reconfigure its system to continue providing reliable service to its customers. Given that the system is already running at a less than optimal configuration as a result, any further contingency that occurs could result in customer outages. That risk of outage is

prolonged if the transmission owner fails to safely remove and replace the damaged or failed equipment in a timely manner. Any risk of outage could result in litigation from customers for damages that result from the outage. And if an outage occurs, it will not only adversely affect the transmission owner's transmission performance metrics, but it will also damage the transmission owner's relationship with its customers. The costs of this reputational damage cannot be recovered through transmission rates and could have longer term impacts on the transmission owner's business.

18. As these examples demonstrate, many of the situations that dictate the need for emergency response are completely outside of the transmission owner's control, introducing significant risks that the transmission owner cannot effectively mitigate. Consistent with good utility practice, Exelon works to mitigate the operational and safety risks associated with installing, owning, and operating transmission infrastructure. The Exelon Operating Companies have significant engineering, field personnel, contractor relationship, work management systems, and resources to ensure all preventative and corrective maintenance tasks are completed, including replacing obsolete or poor performing equipment. Exelon also staffs 24 x 7 transmission operations control centers to monitor the transmission system, direct switching, and manage other field activities to keep our employees and the public safe and to keep our equipment functioning as intended. Despite these efforts, Exelon cannot completely eliminate these operational and safety risks. And the obligation to build, own, and operate ever increasing numbers of Network Upgrades will result in

increased exposure to potential accidents or other events, thereby exposing our company to additional liability.

B. Reliability and Cybersecurity Compliance Risks

19. In my experience, owning, operating, and maintaining Network Upgrades imposes additional NERC compliance risks on transmission owners. Specifically, the transmission owner is responsible for complying with the NERC Reliability Standards for every Bulk Electric System asset on its system (including Network Upgrades). While transmission owners do their utmost to ensure full compliance with the NERC Reliability Standards, there is always the risk of violations (especially as a transmission owner's system becomes more complex as the number of Network Upgrades increases). Importantly, if a violation of a NERC standard does occur, the penalty is not recoverable through transmission rates.

20. Under the NERC Reliability Standards, transmission owners must own and operate their Bulk Power System assets in a manner that assures the effective and efficient reduction of risks to the reliability and security of the grid. Their responsibilities include, but are not limited to, performing asset management and maintenance activities, accurately modeling, designing, and operating the transmission system, engaging in communications with and providing data to relevant parties, protecting assets from physical and cyber security risks, and managing supply chain risks. Transmission owners design programs, policies, processes, and internal controls governing these responsibilities that either meet or exceed the requirements of the NERC Reliability Standards while addressing new and emerging risks to the

reliability and security of the Bulk Power System. The more Network Upgrades that are introduced onto the system, the more risk that a transmission owner faces. For example, the transmission owner must coordinate with more owners and operators of generation resources to ensure reliable interconnection and operations in compliance with the NERC Reliability Standards. Moreover, depending on the location and capacity of an interconnecting generator, the transmission owner may experience increased risks due to reclassifications of the impact of existing assets on its system (e.g., a particular asset may transition from low-impact to medium-impact under the Critical Infrastructure Protection standards). Finally, certain types of generators (such as inverter-based resources) may introduce new complications into planning and operations.

21. Even when programs are implemented, designed, and well-executed, there may be missteps that cause violations of the NERC Reliability Standards. When potential noncompliance issues are identified, the transmission owner must immediately develop mitigating activities to remediate the issue and help prevent reoccurrence (which can be costly for the transmission owner). NERC can and does impose monetary penalties for violations. These penalties can be significant and are not recoverable through rates. Thus, they represent a substantial financial risk to transmission owners. In its 2019 and 2020 Compliance Monitoring and Enforcement Program Annual Reports, NERC reported combined penalty amounts of $18.5

million[1] for twelve (12) full Notices of Penalty (NOP) filed in 2019 and over $2.5 million for eight (8) full NOPs filed in 2020.[2]

22. Importantly, the option for interconnection customers to build certain Network Upgrades heightens the risks of noncompliance with reliability and cybersecurity standards and the attendant penalties. To comply with many of the NERC Reliability Standards, transmission owners must rely on initial records created and activities performed upon the installation and commissioning of a transmission asset.[3] In the case of Network Upgrades for which an interconnection customer has exercised the option to build, the transmission owner will have to transition these assets into its NERC compliance program once it takes ownership so that it can ensure that appropriate records, evidence, reviews, and maintenance intervals are maintained to support reliability and compliance with the standards. The fact that certain information must be transferred from the interconnection customer that built the asset to the transmission owner makes the process more complicated and increases the potential for errors and thus penalties for noncompliance.[4] Additionally, that transfer

[1] Compliance Monitoring and Enforcement Program Annual Report, at p. 9, *NERC,* Feb. 5, 2020, https://www.nerc.com/pa/comp/CE/ReportsDL/2019%20Annual%20CMEP%20Report.pdf (last accessed May 28, 2021).

[2] Compliance Monitoring and Enforcement Program Annual Report, at p. 11, *NERC,* Feb. 3, 2021, https://www.nerc.com/pa/comp/CE/ReportsDL/2020%20Annual%20CMEP%20Report.pdf (last accessed May 19, 2021).

[3] Examples of such standards include FAC-003 (Transmission Vegetation Management), FAC-008 (Facility Ratings), PRC-005 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance), and the suite of Critical Infrastructure Protection standards (physical and cybersecurity protections).

[4] For example, NERC states in its 2021 ERO Enterprise Compliance Monitoring and Enforcement Program Implementation Plan that "[f]ailing to keep accurate inventories of equipment, following asset transfers, addition of new equipment, or mergers and acquisitions, is also resulting in incomplete Protection System Maintenance and Testing Programs that jeopardize the functionality of the equipment to respond to faults or disruptions on the electric system." 2021 ERO Enterprise Compliance Monitoring and Enforcement Program Implementation Plan, at p.12, *NERC,* Nov. 2020,

introduces particular risks with respect to supply chain management: the supply chain concerns highlighted in recent federal government actions, including the Commission's own Notice of Inquiry on Equipment and Services Produced or Provided by Certain Entities Identified as Risks to National Security,[5] are far more difficult to manage when the transmission owner lacks control over the procurement of the new equipment interconnected to its system that it must now own and operate.

23. My experience with Exelon's efforts to implement "lessons learned" after the August 2003 Northeast Blackout demonstrate the significant lengths that transmission owners must go through to mitigate NERC Reliability Standard compliance risks. While Exelon did not experience any compliance violations as a result of the event, it nonetheless had substantial impacts on our business. While Exelon is able to recover its costs for bolstering its compliance programs, applying our compliance programs to an ever-increasing number of Network Upgrades increases the risk of noncompliance and thus financial penalties. Moreover, the burden of addressing new and growing compliance requirements forces transmission owners to dedicate their finite resources to certain priorities over others at times when most transmission owners are undertaking efforts to reduce overall spending.

24. In response to the 2003 Northeast Blackout, we implemented 120 actions to strengthen our compliance program and committed significant resources to adopt new procedures, implement new Energy Management System (EMS) tools, and develop

https://www.nerc.com/pa/comp/CAOneStopShop/ERO%20CMEP%20Implementation%20Plan%20v2.0%20-%202021.pdf (last accessed May 19, 2021).

[5] *Equipment and Services Produced or Provided by Certain Entities Identified as Risks to National Security*, Notice of Inquiry, 172 FERC ¶ 61,224 (2020).

additional dispatcher training programs. Among other actions, we updated 180 EMS displays, created new restoration drills and expanded existing ones to include emergency response activities, underwent an independent review of our vegetation management program, established a new dedicated Transmission System Operations (TSO) emergency response role, adopted a new comprehensive TSO training plan and council, installed disturbance monitors, modified our load shed programs, and reviewed and adjusted our overreaching relay settings. As illustrated by this example, mitigating compliance risks is a time- and resource-intensive process.

C. Environmental Risks

25. Installing, owning, operating, and maintaining transmission assets presents risks from an environmental perspective. Specifically, installing, operating, and maintaining certain transmission equipment can result in inadvertent discharge of contaminants effecting soil and/or water or damage to environmentally-sensitive areas over which transmission systems may cross. Such discharges and emissions are typically regulated by the U.S. Environmental Protection Agency, the U.S. Fish and Wildlife Service, and the U.S. Army Corps of Engineers, and any violation of the environmental regulations governing these discharges and emissions can result in financial penalties, as well as civil and criminal litigation. Moreover, some transmission equipment must be located at sites with preexisting contamination, which heightens the risk of noncompliance with environmental regulations or violations of agreements to remediate and/or mitigate that contamination. While transmission owners work hard to comply with environmental regulations, they

nonetheless assume environmental risks by installing, owning, and operating Network Upgrades. Importantly, the regulatory penalties and civil and criminal penalties that result from litigation are not recoverable through rates. Thus, they present a substantial financial risk to transmission owners and their shareholders.

26. For example, certain types of transmission equipment, such as transformers, phase angle regulators, and high-pressure fluid filled transmission cables, are filled with oil. If that transmission equipment leaks oil into the surrounding environment – whether in the course of routine operations or maintenance or due to damage sustained during a severe weather or other event –the resulting environmental damage could be substantial; a transformer failure might result in a fire and/or oil release of significance given the oil capacity of this equipment. Likewise, a high-pressure fluid filled transmission cable leak might result in a significant release. Depending on the circumstances surrounding the leak, the transmission owner may be subject to financial penalties levied by environmental regulators, or even at risk of litigation.

27. A separate type of environmental risk associated with installing, owning, and operating Network Upgrades relates not to the impact of a transmission owner's transmission equipment on the environment, but rather to existing environmental contamination at the properties on which that equipment is situated. During its normal planning process, the transmission owner may try to avoid installing, owning, and operating transmission facilities in particular areas due to environmental concerns. However, in the case of Network Upgrades, it may have less discretion because it is required to build facilities to accommodate the generator's decision to site in a particular area.

28. In order to install, maintain, and (if necessary) repair that equipment, a transmission owner may incur additional costs for specialized workers, personal protective equipment, soil sampling, disposal of contaminated media (e.g., soil or ground water), and regulatory compliance, among other items. The circumstances requiring these costs to be incurred – preexisting environmental contamination – presents significant risks. For example, working at these contaminated sites might pose safety risks to a transmission owner's crews or contractors, and while a transmission owner can try to mitigate these risks, it cannot eliminate them entirely. Preexisting contamination also presents heightened environmental risks; given the increased complexity of managing concerns over contamination, even routine work at a contaminated site can result in further environmental degradation and, potentially, violations of environmental regulations or agreements on remediation. As noted above, violations of these regulations or agreements could result in penalties and these penalties are not recoverable through transmission rates.

29. As is the case with reliability and cybersecurity compliance risks, Network Upgrades present a unique set of environmental risks as a result of the option for interconnection customers to build certain Network Upgrades. For example, an interconnection customer may choose to construct Network Upgrades on a site that has environmental issues because it is more efficient and cost effective for the generator in the construction process. However, the site may create complications and risks for the Transmission Owner who must own and operate the facility on the problematic site for the useful life of the asset.

30. This exact scenario played out for Public Service Electric and Gas Company (PSE&G) in New Jersey. A third-party interconnection customer constructed a switching station pursuant to the self-build provision of PJM's Interconnection Construction Service Agreement on a site very well known for having contaminated land and repeated, serious environmental issues.[6] Under the agreement, PSE&G was nonetheless required to take operational control and then subsequent ownership of the "self-built" facilities without adequate protections for these environmental risks and liabilities. The result has been over a decade of disagreements (with attendant legal and consultant costs), and the conveyance of the switchyard is still unresolved.

D. Weather and Climate Risks

31. One of the greatest threats to the reliability of the transmission system is severe weather, and this threat is only increasing as the climate changes and severe weather events become more frequent, prolonged, and intense. Severe weather events create substantial risks for transmission owners; they increase the risks of damage to or destruction of a transmission owner's transmission assets, including Network Upgrades, which can result in prolonged service outages. Recent experience in the Exelon Utilities' service territories demonstrates this risk.

32. When Hurricane Isaias struck our Atlantic City Electric Company and Delmarva Power service territories in August 2020, there were over 50 transmission circuits ranging from 69 kV to 230 kV that went out of service because of the storm. Almost

[6] The switchyard is located within the boundaries of a refinery site, which is a known contaminated site subject to the New Jersey Department of Environmental Protection's Site Remediation Program regulations. The portion of the property where the switchyard is located has soil contamination consisting of chemicals associated with petroleum refining and metals (arsenic and lead). In addition, the property also has groundwater contamination, which is a pervasive problem throughout the refinery property.

all of these outages were the result of transmission lines tripping due to faults on the utility's equipment or loss of source. In two cases, the loss of transmission sources to substations resulted in customer outages, with one of those outages affecting approximately 50,000 customers. In the latter case, our crews were able to restore the first transmission source into the area in about five hours. Nonetheless, the damage that Hurricane Isaias wrought on Atlantic City Electric Company's and Delmarva Power's transmission systems is clear evidence of the risks that severe weather events impose on transmission owners, risks that apply equally to the Network Upgrades on their systems.

33. While actual customer outages are the clearest indication that there are risks associated with severe weather events, some events that do not result in outages still pose significant risks for transmission owners. In May 2020, a 138 kV transmission line in Commonwealth Edison's service territory suffered significant damage due to a tornado moving through the area. In total, 17 towers on the line were damaged, with 13 of those towers being knocked down. The transmission line was the only transmission source to the Mendota substation (which also had a 34 kV distribution feed). While the line was being rebuilt, the 3,798 customers served from the Mendota substation were at risk of losing service had there been any contingency on the 34 kV distribution feed. Fortunately, no such contingency occurred, but this situation highlights how damage from severe weather events pose broader risks than the immediate loss of service.

34. When severe weather events damage or destroy transmission assets, transmission owners must engage in emergency response efforts to safely restore service. As

described in section A above, emergency response efforts are not only resource- and time-intensive, they also involve safety and operational risks for transmission owners. Moreover, any service outage – no matter how severe the weather – can damage a transmission owner's relationship with its customers and its reputation with investors. Customers expect reliable electric service, and any delays in restoring service after a severe weather event can harm a transmission owner's reputation. There are also real, consequential financial damages to large process customers. These reputational risks, while impossible to quantify, have real impacts on a transmission owner's business given how critical the community's support is to electric infrastructure development. Moreover, reputational damage leaves transmission owners more vulnerable to customer litigation should their service be interrupted.

E. Outage Coordination Risks

35. To reliably integrate Network Upgrades necessary to accommodate a new generation resource into its system, a transmission owner must manage the project and coordinate outage scheduling of transmission facilities to allow for construction. Outage coordination is particularly risky for transmission owners; it requires meticulous planning and coordination to ensure that Network Upgrades are installed and energized without disrupting service to customers. The risks associated with outage coordination are present whether the transmission owner constructs the necessary Network Upgrades or the interconnection customer elects the option to build. Failure to successfully coordinate outages can result in delays in facility in-service dates, suboptimal transmission system configurations, interference with other

planned outages or other critical transmission projects (some of which may be needed to maintain existing transmission assets to support continued reliable service), or – in the extreme – temporary service disruptions. Each of these issues exposes the transmission owner to financial liability from customers or third parties who may be subject to disruption or delay in service.

36. Coordinating outages becomes more difficult the more complex the transmission system becomes. With recent increases in the number and nameplate capacity of resources in PJM's interconnection queue, the PJM transmission system is increasing in complexity by the year. For example, Commonwealth Edison has 156 active queue projects and the PHI Companies have 133 active queue projects versus 54 and 61 respectively in 2017. As such, the risks associated with coordinating outages that transmission owners face are rapidly growing.

IV. In Addition to Uncompensated Financial Risks, a Transmission Owner's Responsibility for Building Network Upgrades and Integrating Them into Its System Creates Reputational Risks

37. As discussed throughout this testimony, installing, owning, and operating Network Upgrades can introduce reputational risks for transmission owners, risks that create the potential for increased litigation and thus may have a financial impact on the transmission owner. However, I have also witnessed a different type of reputational risk, one that stems from disputes with interconnection customers over issues concerning Network Upgrades. These disputes can lead to litigation that, if publicized, can adversely affect a transmission owner's relationship with its customers, its regulators, and the communities that it serves.

38. Transmission owners expend considerable resources to track and manage Network Upgrade projects and to address interconnection customers' increasing demands that they "focus on my project." For example, interconnection customers are increasingly expressing the desire to enter into commercial service prior to the completion of the necessary interconnection studies and/or execution of the appropriate agreements. They are typically motivated by incentive drivers (such as production tax credits), delivery contracts, or funding commitments. If the transmission owner refuses such a request or the interconnection customer is otherwise unsatisfied with the transmission owner's response, then the transmission owner faces the real potential that the interconnection customer will allege economic harm and potentially litigate. Similarly, an interconnection customer may claim that they are being treated in a discriminatory manner, typically because they are seeking to have the transmission owner address their concerns prior to addressing the concerns of interconnection customers that precede them in the queue. This situation is only exasperated by higher queue volumes, where backlogs can delay the processing of interconnection requests. Again, these interconnection customers may claim financial harm and threaten to litigate.

39. This potential for litigation poses an ancillary, but significant risk to transmission owners: reputational risk. If the interconnection customer threatens or brings legal action against a transmission owner for a purported failure to timely interconnect, it can create public relations problems for the transmission owner, even where the transmission owner has acted within the bounds of the tariff or has otherwise been

unable to meet the demands of the developer. Given the proliferation of renewable generation resources, and the sheer number of projects that are managed, the likelihood of this issue arising is increasing. This reputational damage is even more concerning when the state in which the transmission owner operates has renewable energy or climate goals, as any litigation that alleges that the transmission owner is delaying the interconnection of a renewable energy resource could create the false perception that the transmission owner is not supportive of those state policies. Moreover, even absent litigation, disagreements with or misinformation from interconnection customers can damage a transmission owner's reputation, affecting its relationships with its customers and regulators.

40. This concludes my Affidavit.

I hereby certify under penalty of perjury that the foregoing statements are true and correct to the best of my knowledge, information and belief.

Executed ________________ 6/24/21

ATTACHMENT D

Affidavit of David Hunger and Seabron Adamson of Charles River Associates

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
	)	
PJM Transmission Owners	)	Docket No. ER21-
	)	
	)	

AFFIDAVIT OF DAVID HUNGER AND SEABRON ADAMSON

I. QUALIFICATIONS AND PURPOSE

Q: PLEASE STATE YOUR NAMES, OCCUPATIONS, AND BUSINESS ADDRESSES.

A: My name is David Hunger. I am a Vice President in the Energy Practice of Charles River Associates ("CRA"). My address is 1201 F St. NW, Suite 800, Washington, DC.

My name is Seabron Adamson. I am a Vice President in the Energy Practice of CRA. My address is 200 Clarendon Street, Boston, MA 02116.

Q: DR. HUNGER, WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A: I am experienced in energy market analysis and was formerly a senior economist at the Federal Energy Regulatory Commission ("FERC" or "Commission"). For 14 years at the Commission, I led or participated in analyses involving mergers and other corporate transactions, market power in market-based rates cases, affiliate transactions, investigations of market manipulation in electricity and natural gas markets, demand response compensation, compliance cases for capacity and energy market rules in Regional Transmission Organizations ("RTOs"), and competition issues in electricity markets. Since leaving the FERC and joining CRA in June 2013, I have testified in numerous proceedings involving market power and market design in the organized markets administered by independent system operators ("ISOs") and RTOs. I have submitted testimony on energy-related matters before FERC, state public utility commissions, federal court and an arbitration tribunal. Specific to the matters before the

Commission in this proceeding, I have previously submitted affidavits concerning PJM's market design and transmission policy.

I hold a B.A. in Mathematics from the University of Massachusetts and a M.S. and Ph.D. in economics from the University of Oregon. My experience, education, and prior testimony are described in my curriculum vitae, submitted alongside this affidavit as Attachment CRA-1.

Q: MR. ADAMSON, WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A: I am an energy economist and lead the global energy regulatory and disputes segment of the Energy practice at CRA. I have testified extensively in electric power and other energy sector matters before the Commission, in state and federal court proceedings and in international and domestic arbitration proceedings. In addition to my expert work, I have done advisory work for a wide range of clients regarding contractual, financing, transmission issues and other issues associated with new generation projects, especially for new renewable projects. Before rejoining CRA full-time in 2014, I was an energy analyst and strategist for a major international alternative investment firm.

In addition to my consulting work at CRA, I teach a class on renewable energy project finance in the Department of Finance at the Carroll School of Management of Boston College. I have published several peer-reviewed articles on issues associated with energy markets and investments. I am the co-author of the textbook *Renewable Energy Finance: Theory and Practice* published by the Academic Press in 2020. I hold a B.S. degree in Physics from the Georgia Institute of Technology and a M.S. in Applied Physics from the same institution. I also hold the M.S. in Technology and Policy from the Massachusetts Institute of Technology and a M.A. in Economics from Boston University. My experience, and education are described in my curriculum vitae, submitted alongside this testimony in Attachment CRA-2.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: We provide testimony to analyze and explain the economic and financial issues related to the revisions to the PJM Tariff proposed by the PJM Transmission Owners ("PJM TOs"). These revisions would provide the PJM TOs the option to fund the capital cost of Network Upgrades necessary to accommodate new generator interconnections.[1]

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[1] The term "Network Upgrades" as used in this filing refers to the Network Upgrades required to accommodate the interconnection of generators to the transmission system.

Q: HOW IS YOUR TESTIMONY ORGANIZED?

A: Section II of our testimony provides a summary of our analysis and conclusions. Section III describes at a high level the current method of generator funding of Network Upgrades (hereafter the "Existing Funding Method") in PJM. In Section IV, we discuss how the Existing Funding Method requires the PJM TOs to offer a zero-profit service with no scope for a return, and its economic and regulatory policy implications. Section V discusses the financial risks from potentially unrecoverable costs associated with Network Upgrades, and the implications on the financial stability and ability to raise cost-effective capital of the PJM TOs if the Network Upgrades become a larger part of their total transmission assets. In Section VI, we discuss that while Network Upgrades may have made up a small proportion of total TO assets in the past, new clean energy policies and the required level of new renewable energy capacity in PJM will change this proportion markedly in the future. In Section VII we discuss the PJM TOs proposed tariff revisions and how these proposals help address the issues inherent in the current Network Upgrade funding model. Finally, in Section VIII we conclude with an analysis of some policy implications of Network Upgrade funding in PJM.

II. SUMMARY OF TESTIMONY

Q: PLEASE SUMMARIZE YOUR TESTIMONY AND CONCLUSIONS WITH RESPECT TO THE NEED FOR CHANGES IN NETWORK UPGRADE FUNDING IN PJM

A: Under the Existing Funding Method in PJM, interconnecting generators provide the upfront capital for Network Upgrades. The current mechanism in PJM has important regulatory and financial implications for the PJM TOs:

- Under the Existing Funding Method, the Network Upgrade assets are not placed in the PJM TO's rate base and hence the PJM TOs do not earn a return on the costs of the Network Upgrades.

- The PJM TOs' formula rates allow them to recover allowable operation and maintenance (O&M) costs associated with the Network Upgrades in their transmission rates, but there is no mechanism for a profit on the recovery of the O&M costs. From a PJM TO perspective, currently Network Upgrades are a "non-profit" line of business, which PJM TOs are compelled to offer. While it is true that the PJM TOs do not invest their own capital in Network Upgrades at present, this does not imply that the PJM TOs, as private businesses, should be compelled to own and operate them on a zero-return basis.

- There are risks of uncompensated costs regarding owning and operating Network Upgrades. These risks include regulatory, environmental, reliability, cyber-security and other risks that are discussed in greater detail in the affidavit of Mr.

David Weaver, and which in some cases may not be allowed to be recovered in transmission rates by PJM TOs. These risks and potential costs are therefore born by TO shareholders without compensation, contrary to the regulatory principle that utility shareholders should not be forced to bear risks without a reasonable expectation of a corresponding return.

- While Network Upgrades were a relatively small portion of the total transmission system in the past, the scale of new renewable generation in PJM needed to meet federal and state policy objectives is tremendous. As a result, Network Upgrades will form a substantial portion of all PJM TO assets in the future.

- Under the Existing Funding Model in PJM, with a growing share of assets not entitled to earn a return, shareholders will bear disproportionate risks of uncompensated costs without a return on equity ("ROE") or profit on the facilities to offset those risks. If left uncorrected, this may negatively affect the financial stability of PJM TOs and impact their ability to raise capital at reasonable terms. That in turn could raise rates for all other transmission customers in the future.

- Under the PJM TOs proposed tariff revisions, the TOs would have the option to finance the Network Upgrades and include these capital costs in their rate base, earning a return. These proposals therefore help address the problems associated with the Existing Funding Model.

- PJM is facing the need for substantial growth in new interconnection and the need for significant transmission investment to meet the region's clean energy goals. Moving to a mechanism that allows PJM TOs compensation for the risks associated with adding new interconnection-related Network Upgrades helps preserve their financial stability and ability to attract capital, which is critical in meeting those goals.

III. DESCRIPTION OF THE EXISTING FUNDING MODEL FOR NETWORK UPGRADES IN PJM

Q: PLEASE EXPLAIN THE EXISTING FUNDING MODEL USED IN PJM FOR NETWORK UPGRADES.

A: In simple terms, the current Existing Funding Model relies on upfront payments from the interconnecting generator to pay for the capital costs of the required Network Upgrades.[2]

[2] A more extensive description of the regulatory history of the PJM funding mechanism is provided in the Transmittal Letter, and hence is not repeated here.

Essentially, the interconnecting generator finances the upgrade costs. Unless the generator exercises the Option to Build under the PJM Tariff, the PJM TO builds, owns and operates the Network Upgrades, and recovers only the operations and maintenance (O&M) costs associated with the Network Upgrades in its formula rates.[3]

Q: DO THE PJM TOS HAVE ANY OPPORTUNITY TO EARN ANY PROFIT FROM CONSTRUCTING, OWNING AND OPERATING THESE NETWORK UPGRADE FACILITIES?

A: No. The PJM TOs recover their O&M costs but recovering costs does not provide any profit for the business. Under the current model, there is no ability for the PJM TOs to earn any return or profit on these Network Upgrades, making this essentially a "non-profit" activity. Thus, the PJM TOs are not able to provide any compensation to shareholders for any risks of unrecoverable costs associated with Network Upgrades.

Q: WHY DOES THE RATEMAKING TREATMENT OF THESE NETWORK UPGRADES RENDER THIS A "NON-PROFIT" ACTIVITY?

A: To explain why there are only risks associated with Network Upgrades for PJM TOs, and no potential returns, it is important to start with how transmission rates are established. In simple terms, rates are set to yield an annual transmission revenue requirement ("ATRR"). Following standard cost of service principles, the ATRR has a few basic components. These may be illustrated for a transmission owner as:

$$\mathbf{ATRR = O + D + T + kB}$$

Where O represents operating expenses, D represents depreciation expenses, T taxes, k the allowed rate of return and B the utility's rate base.[4] The utility earns any profit through its rate of return (k) that is multiplied by its rate base (B). If the applicable rate base value is zero than there is zero profit. Under the current Existing Funding Model, the capital for Network Upgrades is provided by interconnection customers and included in the TO's rate base at zero. There is therefore no scope for return or profit associated with the Network Upgrade included in the PJM TO's rates. The operations and maintenance expenses associated with the upgrades are included the ATRR and hence in rates, but the associated revenues and O&M expenses offset so there is no return or profit from this component. There is also a true-up mechanism that ensures any short-run differences between the rates charged and actual recoverable costs are recaptured over time.

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3 Transmittal Letter at page 3. Even if the generator builds the projects, the TO still owns and operates the project and only recovers the O&M costs.

4 Roger A. Morin, *New Regulatory Finance*, 9-13 (Public Utilities Reports, Inc., 2006).

Q: WHAT HAPPENS IF THERE ARE O&M COSTS ASSOCIATED WITH THE NETWORK UPGRADES THAT ARE NOT ELIGIBLE FOR RECOVERY?

A: The risks associated with these potential costs are central to why a new funding mechanism is needed. As we discuss in detail in Section V of this affidavit, if there are risks of unrecoverable costs, then these risks are being borne by PJM TO shareholders without compensation. Without a return on the Network Upgrades, there is no mechanism to provide compensation for shareholders for bearing these risks. As a result, shareholders have downside risk of potentially being exposed to costs associated with Network Upgrades, but no offsetting potential upside or profit.

IV. TRANSMISSION OWNERS ARE COMPELLED TO OWN AND OPERATE NETWORK UPGRADES ON A NON-PROFIT BASIS

Q: WHY DO YOU CHARACTERIZE THE EXISTING PROVISION OF NETWORK UPGRADES AS REQUIRING PJM TOS TO OFFER A NON-PROFIT SERVICE?

A: As was described in the previous section, Network Upgrades are not in the PJM TO's rate base, so there is no ability to earn a return for the upgrade. The PJM TOs earn a profit through their returns. Recoverable O&M costs are included in rates, but there is no potential for a return or profit for O&M costs either. Thus, the Existing Funding Model forces the PJM TOs to operate a substantial (and growing) portion of their business on a "non-profit" basis.

Q: WHY IS THIS A CONCERN?

A: The PJM TOs, like other investor-owned utilities regulated by the Commission, are private enterprises operated on a profit-making basis. They are regulated, but they are not charities. No private business would choose to operate a business that earns no profit on a portion of its assets, unless there were other benefits to it, which there are not here. Imagine the response if the owner of a supermarket, for example, was told that she can only sell canned goods at cost (i.e., no profit will be allowed on sales), but that she had to devote as much time and shelf space to these goods as customers demanded. As the portion of her shelves holding non-profit canned goods grows, her business would start to decline. If the non-profit portion of her shelves grow too much, it would undermine the financial stability of her store. Under the Existing Funding Model, PJM TOs are in the same predicament. They are required to devote time and effort to build, own, and operate Network Upgrades just as they do for their other transmission assets, but they are required to operate the Network Upgrades as a non-profit segment of their business. There is a fundamental unfairness about requiring private companies to operate a non-profit business; this is not something commonly observed in our economic system. A company may choose to operate a line of business without expectation of a profit if it furthers other business purposes. For the PJM TOs, this is not the case.

Q: UNDER THE EXISTING FUNDING MODEL, THE PJM TOS ARE NOT REQUIRED TO MAKE THEIR OWN CAPITAL INVESTMENT IN THE UPGRADES. SO WHY IS IT A PROBLEM IF THERE NO OPPORTUNITY FOR PROFIT?

A: Capital investment is not the only resource that a company invests into a line of business. A company also invests scarce employee and management time, and management focus on each segment of its business, and these have opportunity costs for companies. Private companies often undertake commercial activities in which they invest minimal or no capital, but they do not do it if there is no potential for future profitability.

Q: IS THE INVESTMENT OF CAPITAL THE ONLY FACTOR IN DETERMINING WHETHER AN ACTOR SHOULD BE ALLOWED TO EARN A PROFIT ON A PORTION OF ITS BUSINESS?

A: No. Well established regulatory principles, as enumerated in the *Hope* and *Bluefield* decisions,[5] require that a utility be allowed a return that is sufficient to attract capital and to provide comparable earnings to other investments given the risks assumed and to ensure the financial integrity of the utility.[6] The principles of U.S. regulatory policy require that if capital is invested by a utility a reasonable return must be allowed, but this is fundamentally different from a requirement to run a non-profit business just because none of the firm's capital has been employed in it. As we discuss later in this affidavit, compelling PJM TOs to offer a non-profit service for Network Upgrades also has implications for the financial stability and ability to attract capital central to the regulatory policies established from the *Hope* and *Bluefield* decisions as well.

Q: ARE THERE OTHER EXAMPLES OF PARTICIPANTS WHO DO NOT MAKE A DIRECT PHYSICAL CAPITAL INVESTMENT IN A PROJECT BUT STILL EXPECT TO MAKE A PROFIT?

A: Yes. For a new generation project, for example, the project developer will typically pay numerous contractors to supply services or construct a project, including contractors who will design, build and often operate the "wires"-type assets that connect the generators to the point of interconnection. These services are analogous to the services that PJM TOs provide with respect to Network Upgrades. However, these private contractors do not build and operate the generator interconnection facilities for free. Rather, they expect a profit for the services that the provide, even though they typically also make no capital investment of their own in the project.

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5 *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) ("*Bluefield*").

6 Roger A. Morin, *New Regulatory Finance*, 9-13 (Public Utilities Reports, Inc., 2006).

Q: HAVE THE COURTS HIGHLIGHTED THIS ISSUE OF REQUIRING A PRIVATE ENTERPRISE SUCH AS THE PJM TOS TO OFFER A SERVICE ON A NON-PROFIT BASIS?

A: Yes. In its decision in the *Ameren* case, the D.C. Circuit highlighted this issue in a decision regarding an analogous situation in Midcontinent Independent System Operator, Inc. ("MISO"). In MISO, transmission owners were also forced to operate Network Upgrades "with operations and maintenance costs reimbursed, but no return."[7] The DC Circuit noted that in this case the "transmission owners' desire to retain the choice to fund the upgrades is much more than a claim to entitlement to the generator's "financing business." It is, at root, a desire to retain control over their *own* business."[8]

Q: WHAT DO YOU CONCLUDE REGARDING THE EXISTING FUNDING MODEL AND ITS OBLIGATION FOR PJM TOS TO OFFER THIS SERVICE ON A NON-PROFIT BASIS?

A: Requiring private enterprises to offer non-profit services is not a feature of the American economic system. This is especially problematic in the current case, for associated reasons the *Ameren* court highlighted in its decision, several of which will be addressed later in this affidavit.

V. THE EXISTING FUNDING MODEL REQUIRES TRANSMISISON OWNER SHAREHOLDERS TO BEAR FINANCIAL RISKS WITH NO POTENTIAL RETURN

Q: WHAT RISKS DO TRANSMISSION OWNERS BEAR ASSOCIATED WITH OWNING AND OPERATING THE NETWORK UPGRADES UNDER THE EXISTING FUNDING MODEL USED IN PJM?

A: As was discussed in the previous section, the TO is typically able to recover O&M costs associated with Network Upgrades. However, there may be circumstances when not all costs are recoverable (e.g., North American Electric Reliability Corporation penalties). PJM TOs bear the risks associated with any costs not recovered in transmission rates. These unrecoverable costs could include, for example, reliability, regulatory, cyber-security and environmental costs associated with constructing, operating and finally decommissioning Network Upgrades.

Q: PLEASE PROVIDE EXAMPLES OF RISKS IMPOSED ON TRANSMISSION OWNERS BY THESE NETWORK UPGRADES THAT COULD RESULT IN UNRECOVERED COSTS.

A: The affidavit of David W. Weaver, P.E., Vice President of Transmission Strategy at Exelon, discusses the risks faced by transmission owners in PJM. These risks include, for

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7 *Ameren Servs. Co. v. FERC*, 880 F.3d 571, 582 (D.C. Cir. 2018) ("*Ameren*").

8 *Id.* (emphasis in original).

example, environmental risks associated with building and operating transmission assets, risks associated with cyber-security events, operational and safety risks, etc.

Q: HAVE THESE RISKS BE DISCUSSED BY THE COURTS?

A: Yes. In the *Ameren* decision, the DC Circuit highlighted many of these same risks. For example, the court stated that the transmission owners in MISO bear environmental risks, and that under participant funding (e.g., similar to the Existing Funding Model in PJM) that risk may be borne by the transmission owner and its shareholders without any corresponding benefit. The court held that the Commission cannot compel a transmission owner to operate even a portion of its business on a non-profit basis.

Q: ARE SUCH RISKS OF NON-RECOVERABLE COSTS SYMMETRIC?

A: No. These types of risks are by their nature asymmetric, implying that while there could be potential losses from such a risk event, there will not be equivalent "upside."

Q: WHY IS THE ASYMMETRY OF THESE RISKS IMPORTANT?

A: As addressed in this affidavit, the Existing Funding Model has zero potential profits for PJM TOs. Thus, at best, the PJM TOs break even on Network Upgrades. At worst, there is an unexpected risk event leading to a substantial financial loss for PJM TO that would be borne by shareholders. From a risk perspective, the current system might be characterized informally as "Heads We're Even, Tails I Lose".

Q: SO OVER TIME WILL THE EXISTING FUNDING MODEL CREATE LOSSES FOR PJM TOS?

A: Yes. There is no upside for PJM TOs, but there is a downside risk if not all Network Upgrade-related costs are recoverable. On an expected value basis, this "Heads We're Even, Tails I Lose" model will produce losses over time for PJM TOs and their shareholders.

Q: ARE PJM TOS COMPENSATED FOR TAKING THESE RISKS ASSOCIATED WITH NETWORK UPGRADES, AS THEY ARE FOR RISKS ASSOCIATED WITH THEIR TRANSMISSION ASSETS IN RATE BASE?

A: The risk of uncompensated loss is present for all transmission assets. However, the difference is that there is an opportunity to earn a return or profit on other rate base transmission assets. Thus, while the risk of uncompensated loss exists for these other transmission assets, there is the upside gain of potential profit through a return on those facilities. In contrast, Network Upgrades provide a different dynamic. The downside risk of uncompensated loss remains but there is no upside of profit or gain to offset that risk.

VI. INCREASING NETWORK UPGRADES WILL HAVE A MAJOR IMPACT ON PJM TOS

Q: WHAT FACTORS ARE AFFECTING THE NUMBER OF GENERATION REQUESTS AND THE ASSOCIATED NETWORK UPGRADES REQUIRED TO ACCOMMODATE THOSE REQUESTS?

A: The United States is in the midst of a significant push in federal and state policies to move from a fossil fuel-dominated generation fleet to a greater reliance on new renewable generation and storage. In order to accomplish these goals, there will need to be an increasing amount of Network Upgrades to accommodate the interconnection of these new renewable resources.

Q: WHAT ARE THE SPECIFIC POLICIES AND HOW WILL THEY AFFECT PJM IN PARTICULAR?

A: First, at the federal level, the Biden Administration has announced a target for the United States to achieve a 50-52 percent reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030.[9] A large part of that reduction will come from the electricity sector, which is second to transportation in term of greenhouse gas emissions.[10] This is in addition to a host of existing and proposed policies that will require a significant increase in renewable generation and associated Network Upgrades to accommodate them on the system. Table 1 shows some proposed federal policies that will require or shape investment in new renewables and their associated Network Upgrades.

Table 1: Proposed or current federal policies affecting new interconnection requirements[11]

Renewable Energy Policies	Carbon Emissions Reductions
30 GW Offshore Wind by 2030 and 100 percent carbon pollution-free electricity by 2035	50-52 percent reduction from 2005 levels in economy-wide net greenhouse gas pollution in 2030 (Paris NDC)
Existing and potential changes to Investment Tax Credit (ITC)	Net zero emissions economy-wide by no later than 2050 (Paris alignment)
Existing and potential changes to Production Tax Credit (PTC)	EPA regulations under Clean Air Act (follow on to CPP / ACE)

9 www.whitehouse.gov, Press release dated April 22, 2021.

10 U.S. Environmental Protection Agency, "Sources of Greenhouse Gas Emissions", available from www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

11 Sources provided in Attachment CRA-3.

At the state level, there are also proposed, or current policies related to renewables development and carbon goals in most of the PJM states and the District of Columbia in addition to the federal policies. These are briefly summarized in Table 2 below.

Table 2: Proposed or current state policies affecting new interconnection requirements[12]

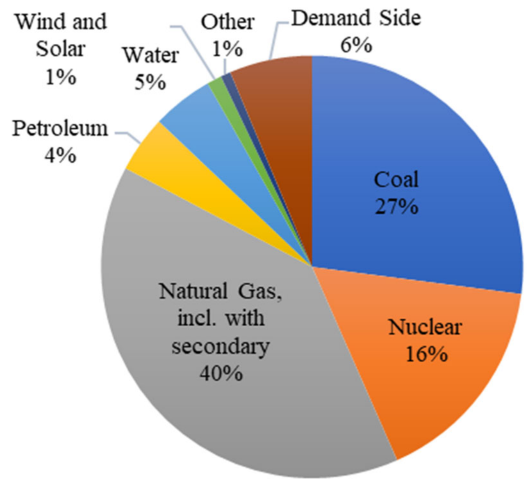
State	Renewable Energy Target	Carbon Emissions Reduction Target
Delaware	RPS: 25% renewables by 2025, 28% by 2030, and 40% by 2035.	30% below 2008 levels by 2030
District of Columbia	100% renewable electricity by 2032	50% reduction from 2006 levels by 2032, carbon neutral by 2050
Illinois	RPS: 25% by 2025-2026, and beginning 2016, 6% annually must be solar PV	Reduce GHG emissions by at least 26-28 percent below 2005 levels by 2025
Indiana	Goal, not standard. 10% by 2025	N/A
Kentucky	N/A	N/A
Maryland	RPS: 30.5% renewables in 2020; 50% in 2030	40% below 2006 levels by 2030
Michigan	Renewable Energy Standard: 15% by 2021 (standard), 35% by 2025 (goal, including energy efficiency and demand reduction)	Net carbon neutrality by 2050
New Jersey	RPS: 50% Class I renewables by 2030. 2.5% Class II renewables each year. 5.1% solar-electric by 2021, then gradually reduced to 1.1% by 2031.	Reduce to 1990 levels by 2020, 80% below 2006 levels by 2050
North Carolina	RPS: 12.5% by 2021 (IOUs); 10% by 2018 (municipals and coops)	40% below 2005 levels by 2025
Ohio	In 2019, Ohio reduced its RPS requirement and eliminated its solar-carveout. The state reduced its RPS from 12.5% to 8.5% by 2026	N/A
Pennsylvania	AEPS: 18% by 2020-2021	26% below 2005 levels by 2025, 80% below 2005 levels by 2050
Tennessee	N/A	N/A
Virginia	Phase I utilities: renewables target of 14% by 2025, 30% by 2030, 65% by 2040, and 100% by 2050. Phase II utilities: 26% by 2025, 41% by 2030, and 100% by 2045	Net-zero across all sectors by 2045
West Virginia	N/A, repealed 2015	N/A

As shown in Figure 1, PJM is still largely dependent on fossil-fired generation. Achieving federal and state renewable energy and carbon emissions reduction goals will require a

12 Sources provided in Attachment CRA-3.

large amount of new renewable energy generation to be interconnected across the PJM footprint.

Figure 1: PJM installed capacity by fuel type, 2020[13]



Moreover, since renewables often have a lower capacity factor than fossil-fired generation, the need for additional megawatts of new renewable generation capacity is likely to be substantially higher than the number of fossil-fired generation megawatts that they are replacing. In addition, we expect that substantial new storage capacity will also be interconnected in the future, potentially increasing the total demand for Network Upgrades.

Q: PLEASE DESCRIBE THE CURRENT AND EXPECTED FUTURE PJM INTERCONNECTION QUEUES.

A: As shown in Figure 2, the amount of new generation interconnection requests has risen steadily, in energy terms, from 35.5 GWs in 2015 to 66.9 GWs in 2020.

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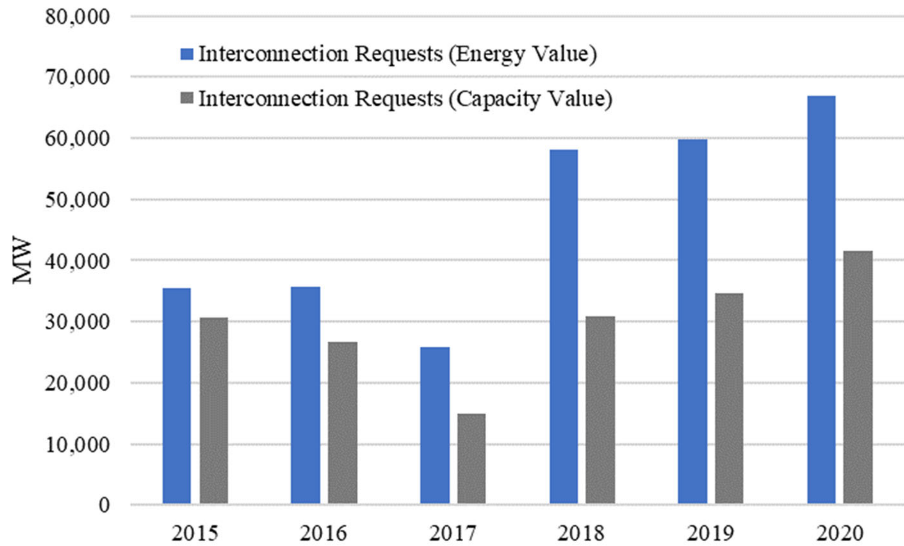
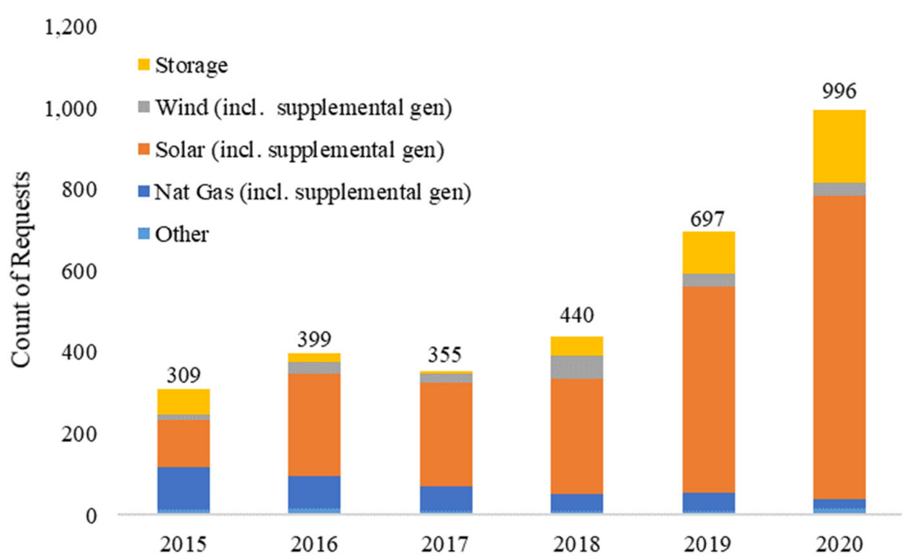
13 PJM, "Capacity by Fuel Type" (https://sdc.pjm.com/-/media/markets-ops/ops-analysis/capacity-by-fuel-type-2020.ashx)

Figure 2: Generation interconnection requested[14]



In addition, the number of requests has increased from 309 in 2015 to 996 in 2020. Based on the necessary major changes in the generation mix over the next decade, we expect those numbers to continue rising in both the number of requests and gigawatts of generation.

Figure 3: Count of generation interconnection requests by year in PJM[15]



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14 CRA analysis of PJM New Services Queue data, downloaded May 8, 2021.

15 CRA analysis of PJM New Services Queue data, downloaded May 8, 2021.

Q: WHAT PERCENTAGE OF GENERATION IN THE INTERCONNECTION QUEUE BECOMES OPERATIONAL?

A: That depends on the status of the project within the queue. Historically, that percentage from the time entering the queue to completion had, on a project basis, hovered around 20 percent (in the 2015 period) but has increased to closer to 23 percent in the last three years.[16] Likewise, of all MW of Capacity Interconnection Rights (CIRs) to enter the queue, now close to 15 percent is completed, while that number had historically been closer to 10% (also in the 2015 period). More importantly, the percentage of projects that have reached the Facilities Study Phase becoming operational is much higher (45 percent) and relevant here because as of May 2021, there are 782 projects representing over 44 gigawatts of capacity that have reached the Facility Studies Phase in PJM.[17]

Q: SHOULD THE HISTORICAL RATE OF PROJECTS IN THE QUEUE BECOMING OPERATIONAL DRIVE FUTURE ESTIMATES OF POTENTIAL REQUIRED INTERCONNECTIONS OF NEW GENERATION?

A: No. The transmission interconnection queue gives a snapshot of potential generation projects at present, but it does not extend far into the future. As we have described above, a major driver of new generator interconnections will be public policies related to the decarbonization of the power sector. That will require very large amounts of new renewable generation, based on current trends. The key question is not the future megawatts in the queue but how many megawatts of new capacity are required to come online. One might expect that the queue capacity may always be much larger, but the key is to look at the new megawatts that need to enter service in the coming decades to meet policy goals.

Q: HOW MANY MEGAWATTS OF NEW GENERATION MAY ENTER SERVICE IN THE COMING DECADE OR SO?

A: This is of course highly uncertain, and the total quantity depends on progress in implementing clean energy programs and many other factors. Given the policy proposals discussed previously, the quantities of new renewable generation could be very large indeed. For example, in 2020 fossil-fired generation (coal, natural gas and oil) produced approximately 481,000 gigawatt-hours (GWh) of electricity in PJM.[18] As an illustration, to replace all of this fossil-fired generation would require additional renewable energy

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16 PJM 2020 Regional Transmission Expansion Plan, Book 1, page 10.

17 PJM Infrastructure Planning Committee, *Interconnection Process Reform Task Force Update* at p. 21, May 11, 2021.

18 Monitoring Analytics, "2020 State of the Market Report for PJM", Members Committee Briefing, March 29, 2021. Available from www.pjm.com.

capacity of approximately 183 gigawatts (GW) assuming a capacity factor of 30%.[19] Total installed generation capacity in PJM is currently around 185 GW.[20] To meet a 2035 decarbonization target for PJM might therefore imply adding additional renewable generation on a massive scale – on the same scale as the entire amount of generation in the PJM Region.

Q: WHAT ARE THE POTENTIAL IMPLICATIONS FOR NEW NETWORK UPGRADES ASSOCIATED WITH THE LEVEL OF NEW POTENTIAL RENEWABLE GENERATION?

A: The total cost of Network Upgrades associated with a shift to renewable generation is difficult to assess precisely. These costs will depend on the type and location of new generation, usage and construction of transmission capacity, technological change, and other parameters. These costs are not predictable in detail for such a sweeping transformation over a period of many years. However, it appears likely that associated Network Upgrades under the Existing Funding Model would reflects costs of many billions of dollars, with important implications for the PJM TOs.

VII. THE CURRENT MODEL FOR NETWORK UPGRADES MAY IMPACT THE FINANCIAL STABILITY OF PJM TOS AND THEIR ABILITY TO ATTRACT CAPITAL AT REASONABLE RATES

Q: HOW WOULD RAPIDLY INCREASING AMOUNTS OF NEW NETWORK UPGRADES AFFECT THE ASSETS OF THE PJM TOS?

A: Under the Existing Funding Model, a PJM TO in simple terms owns and operates two types of transmission assets. It has transmission assets that are represented in its rate base, and it can earn a return on those assets. It also has a set of transmission assets that are Network Upgrades, and these are not reflected in rate base. Any risks of non-recoverable costs associated with the Network Upgrades are borne by the shareholders, but the shareholders in effect only have the scope for a potential return on the rate base assets. In the past, the proportion of Network Upgrades has been small, so that rate base assets have been a high proportion of all transmission assets (rate base assets plus non-rate base assets). Thus, while a risk burden has always been placed on shareholders, until recently, the burden has been relatively small.

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[19] Calculated as 481,135 GWh/ (30% capacity factor * 8760 hours/year) = 183.1 GW.

[20] PJM, "Capacity by Fuel Type" (https://sdc.pjm.com/-/media/markets-ops/ops-analysis/capacity-by-fuel-type-2020.ashx)

Q: HOW WILL THESE RISKS CHANGE IF THE PROPORTION OF NETWORK UPGRADES RISES SIGNIFICANTLY AS A SHARE OF TOTAL TRANSMISSION ASSETS?

A: As discussed previously, the proportion of non-rate base assets related to Network Upgrades is expected to grow sharply, and hence the risk burden on shareholders will be magnified substantially. As noted by Mr. Weaver, the risks associated with owning and operating transmission assets such as Network Upgrade facilities can be expected to grow as the volume of those assets grow. As the number of Network Upgrades grows, the financial risks will grow, but the proportion of rate base assets to total transmission assets will fall. This will amplify the risks for shareholders, who will face larger potential losses on a smaller proportion of rate base assets – the only assets on which they can earn a return.

Q: PLEASE PROVIDE A SIMPLE EXAMPLE OF THE POTENTIAL IMPACT ON UTILITY FINANCIAL STABILITY FROM A LARGE RAISE IN NON-RATE BASE ASSETS

A: Consider a utility (Utility A) with a rate base of $100, which has a Weighted Average Cost of Capital (WACC) of 7% and hence receives an annual return of $7 on its rate base. Utility A has no Network Upgrades so all $100 of its total transmission assets are in rate base. It also has operating, maintenance, and other expenses, and there is the potential for costs that cannot be recovered in rates. Assume in a year that the amount of uncompensated costs is $5. If the loss event occurs, the utility shareholders will face a substantially diminished return of $2, with a proportional loss of 5% of its total rate base value. Such risks will in general have been built into the expectations of investors, and thus reflected in the WACC of 7%,

Now consider Utility B, which also has a rate base of $100 and a WACC of 7%, but it also has other transmission assets *not* in its rate base (e.g., Network Upgrades) of another $100. Its total transmission assets are thus $200. We assume the same potential for costs that cannot be recovered in rates. However, the scope for any losses is proportional to the total transmission assets in service, so the potential loss for Utility B is $10.[21] If the loss occurs for Utility B, its shareholders will face a negative return of -$3. The shareholders of Utility B face disproportionate losses since their value in the business (as represented in the rate base, on which they can earn a return) is proportionally much smaller. Thus, it is easy to see why Utility B would face greater risks to its financial stability and ability to raise capital at a reasonable return. Having a large proportion of non-rate base assets effectively "leverages" the remaining rate base, with no compensating scope for return, increasing risks.

[21] The proportional loss is again 5%. However, that loss must be applied to the total transmission assets of $200 so the loss = 5% * $200 = $10.

Q: IF THIS PROPORTION OF NON-RATE BASE ASSETS BECOMES SIGNIFICANT, AS YOU FORECAST, HOW COULD THIS AFFECT INVESTORS VIEWS' OF THE PJM TOS?

A: Investors provide capital to companies with the expectation of reasonable risk-adjusted returns. For cost of service-regulated utilities, the potential returns are linked to the level of the rate base, as these are the only assets on which investors can earn a return. Under the Existing Funding Model, future rate base assets will be burdened with uncompensated risks associated with the growing number of Network Upgrades. Investors will reasonably expect that these risks will fall on shareholders and thus impact their returns.

Q: COULD THIS MECHANISM AFFECT THE COST OF CAPITAL OF TRANSMISSION OWNERS IN THE FUTURE?

A: Yes. In the short run the current model imposes risks and potential uncompensated losses on shareholders. But in the future, investors will expect higher risks on returns on the rate base, as these rate base assets are absorbing risks associated with all transmission assets, both rate base and non-rate base. Logically, investors will require higher returns in the future if risks are perceived to be higher.

Q: IF THE COST OF CAPITAL IS IMPACTED BY THIS MECHANISM, COULD THIS IMPACT OTHER TRANSMISSION CUSTOMERS?

A: Yes. The PJM TOs are highly capital-intensive businesses, and even small changes in the WACC may have a significant impact on transmission rates. Shareholders may be impacted most at first, but eventually increased risks will impact transmission rates as the cost of capital increases. This will not be beneficial to electricity customers in PJM.

VIII. THE PROPOSED TARIFF REVISIONS REDUCE THE RISKS OF UNCOMPENSATED RISKS BEING IMPOSED AND THE CURRENT REQUIREMENT TO OFFER A ZERO-PROFIT SERVICE

Q: PLEASE BRIEFLY DESCRIBE THE BASIC COST RECOVERY PRINCIPLES UNDERLYING THE PROPOSED TARIFF REVISIONS

A: As described in more detail in the Transmittal Letter, the proposed revisions to the PJM Tariff provide the PJM TOs with the option to fund required Network Upgrades. The Transmission Owner and the parties will enter into a Network Upgrade Funding Agreement ("NUFA"). The NUFA will define the duration and other terms of the repayment of upgrade costs. The standard term for cost recovery under the *pro forma* NUFA will be twenty years. The annual charge will be based on the initial upgrade capital costs and levelized using a fixed charge rate.[22]

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[22] Transmittal Letter at page 22.

Q: HOW DOES THIS PROPOSAL ELIMINATE THE RISKS OF UNCOMPENSATED RISKS BEING IMPOSED ON TRANSMISSION OWNERS?

A: Under the proposed tariff revisions and NUFA structure, the PJM TO will incorporate the capital costs of the Network Upgrades into their rate base and earn a return on the capital costs of the Network Upgrades. As explained previously, charging an approved return on rate base is used to compensate for the risks associated with deploying capital to provide transmission service and the inherent risks associated with operating a transmission business. By allowing PJM TOs to incorporate the Network Upgrade capital costs into their rate base, an opportunity to make a return commensurate with the underlying risks is created. This is the ordinary method used by the Commission to reflect the risks of owning and operating electric transmission assets, so allowing this method to be used for Network Upgrades capital costs aligns regulatory practice in this special case with the common framework of cost-of-service regulation, as used in the electric transmission sector for decades.

Q: DOES THIS PROPOSAL ELIMINATE THE REQUIREMENT FOR TOS TO OPERATE A ZERO PROFIT BUSINESS, AS HIGHLIGHTED IN THE *AMEREN* DECISION.

A: Yes. As we understand it, in its *Ameren* decision the DC Circuit expressed a concern for transmission owners being required to own and operate transmission facilities without the ability to earn a return on those facilities. The tariff proposals of the PJM TOs eliminate this problem by allowing a return on the capital employed in constructing the upgrades, the same manner as they allow the potential (but not the guarantee) of a profit for other regulated transmission asset operations. These proposed changes would thus eliminate the "zero-profit business" concerns of the *Ameren* decision as well.[23]

Q: WILL THE REQUIREMENT TO ALLOW A RETURN BY PJM TRANSMISSION OWNERS ON THE COST OF NETWORK UPGRADES AFFECT THE TOTAL COSTS OF INTERCONNECTING NEW GENERATORS?

A: We understand that this may be a concern, but it must be realized that a return on the underlying capital expenditure on Network Upgrades must be earned somewhere. Investor capital is not free, to generation developers or TOs. Under the current model, new generators seeking to interconnect must pay for the required Network Upgrades upfront. Those generators must raise the capital either through the debt or equity markets and investors will rationally seek a return on this capital. Under the proposed model, the PJM TOs may elect to fund the system upgrade capital expenditures and recover these costs over time through levelized charges defined in the appropriate NUFA. The PJM TOs will charge the generator a return on the capital invested based on the WACC established by

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[23] *Ameren* at 582.

the Commission in their respective formula rate. In either case a return on the capital used to fund these upgrades is necessary.

Q: WHAT COST OF CAPITAL WILL BE EMPLOYED BY THE PJM TOS IN CALCULATING THE LEVELIZED CHARGES FOR NEW TRANSMISSION FACILITY UPGRADE SUNDER THE NUFA?

A: The fixed charge rate incorporated into the NUFA charges will be based on the approved WACC of the specific PJM TO. The levelization will use a discount rate which is set based on the WACC adjusted by the combined tax rate of the utility.[24]

Q: DO PJM TOS HAVE A RELATIVELY LOW WEIGHTED AVERAGE COST OF CAPITAL?

A: Yes. In general FERC-regulated transmission owners have a relatively low cost of capital, due to the nature of their business. The PJM TOs in general are large, regulated entities with strong credit profiles, and with strong access to the bond markets. On the equity side, the transmission owners show market risk characteristics that are favorable. Together, these factors suggest that the PJM TOs will have a low WACC.

Q: IS THERE ECONOMIC EVIDENCE TO SUGGEST THAT TRANSMISSION OWNING UTILITIES MAY IN GENERAL HAVE AN ATTRACTIVE COST OF EQUITY IN COMPARISON TO GENERATORS?

A: Yes. For example, one of the methods the Commission uses in its ROE methodology is the Capital Asset Pricing Model ("CAPM"). The CAPM approach is widely used to establish the required cost of capital for various types of capital projects.[25] Under the CAPM approach, the required return that an investor would expect increases with a market risk factor "beta", which reflects non-diversifiable market risks associated with the investment. All else equal, a higher "beta" translates to a higher level of market risk and a higher required return.

Q: ARE THERE COMPARISONS OF BETAS THAT WOULD ALLOW BROAD COMPARISON OF THE COST OF EQUITY FOR UTILITIES WITH THOSE OF GENERATORS?

A: Yes, to some degree, limited by the level of detail in easily accessible public data sets. For example, Professor Aswath Damodaran, a well-known financial valuation expert at the Stern School of Business at New York University, publishes on his website average betas

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24 *See Pro Forma* Network Upgrade Funding Agreement, Schedule B.

25 For a more complete description of the CAPM and regulatory applications, *see* Roger A. Morin, *New Regulatory Finance,* (Public Utilities Reports 2006).

by sector.[26] For the period 2016 to 2020, for example, the "Power" sector which includes many electric utilities had a beta (unlevered) of 0.43, while that for the "Green & Renewable Energy" sector had a beta of 0.68, reflecting a higher level of market risk.[27]

Q: WHAT IMPLICATIONS DO YOU TAKE FROM THIS DATA?

A: Unsurprisingly, it appears regulated U.S. utilities will generally have a lower cost of equity in the CAPM framework, in comparison to new renewable generators.

Q: WHAT TIMING ISSUES EXIST FOR FUNDING NETWORK UPGRADES BY GENERATORS

A: Under the Existing Funding Model for Network Upgrades associated with new generation, generators must pay for such upgrades before the project enters service. At this stage, the risks to a new renewable project for example are typically higher, and instead of permanent term loans developers often rely on higher cost construction loans. This could tend to raise the costs of funding Network Upgrades under the current model.

Q: HAVE YOU MADE DIRECT COMPARISONS OF THE WACC FOR THE PJM TOS AND THOSE OF INTERCONNECTING NEW GENERATORS?

A: No. There are many different current and potential generation developers and owners in the PJM region, and each will have differing financial structures and options. There are also complex financial structuring, tax and other considerations to be considered, and these may vary considerably between new generation projects. It is therefore difficult to make precise comparisons. Our observations here are limited to the fact that transmission owners, due to their business model, have a relatively low WACC and that this should help assuage concerns about increased net interconnection costs under the proposed tariff reforms.

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26 Data available from http://pages.stern.nyu.edu/~adamodar/New_Home_Page/datafile/Betas.html. Please note that the sectors as defined in the NYU data include a range of companies with different business models, sizes, etc., so beta comparisons are illustrative only.

27 *Ibid.*

IX. POLICY IMPLICATIONS OF THE PROPOSED TARIFF CHANGES

Q: WHY DO NETWORK UPGRADES ASSOCIATED WITH NEW GENERATION INTERCONNECTIONS HAVE SIGNIFICANT REGIONAL AND NATIONAL POLICY IMPLICATIONS?

A: PJM is the largest organized power market in the United States, covering all or part of 13 states and the District of Columbia.[28] As PJM has noted, more and more the states are driving energy policy goals, and that many of these goals center of development of new clean energy resources, primarily renewable generation.[29] The various PJM states will be unable to meet their clean energy goals without interconnecting very large amounts of new generation. Policies that aid that new generation interconnection are thus critical.

Q: HOW DOES THE PROPOSED FUNDING MECHANISM HELP ACHIEVE THOSE CLEAN ENERGY POLICY GOALS?

A: First and foremost, allowing the PJM TOs to recover the costs of interconnection-related system upgrades helps compensates them for the risks incurred in building and operating these assets. Second, as we have noted above, at present the mechanism is at best a "zero-profit" business, in which a PJM TO can only lose. It is economically irrational to expect private transmission owners to operate a business without even the potential for profit, and even more irrational to expect them to wish to see this business expand. Allowing recovery of these Network Upgrade costs in the rate base allows PJM TOs to grow this business like their other regulated businesses, but without the zero-profit growth disincentive inherent in the current model.

Q: DOES THE SHIFT IN FUNDING MECHANISM FOR THESE NETWORK UPGRADES HAVE POTENTIAL BENEFITS FOR THE FINANCIAL HEALTH OF THE PJM TOs AND THEIR ABILITY TO ATTRACT CAPITAL?

A: Yes. As noted previously, under the current mechanism the PJM TOs will become increasingly thinly capitalized, with a smaller proportion of rate base to the transmission assets that they operate. This implies any residual risks associated with these non-rate base assets (e.g. currently participant-funded assets) will affect the financial returns on a smaller proportion of rate base assets, which could impact their ability to raise capital on reasonable returns. The current system imposes a "risk burden" on the rate base and PJM TO shareholders, and that burden appears likely to grow substantially. The Commission should ensure that these risks are adequately compensated so as ensure the PJM TOs will be able to access the large amounts of capital needed in the future on reasonable terms.

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28 https://www.pjm.com/about-pjm/who-we-are.aspx

29 https://insidelines.pjm.com/2020-in-review-planning-prepares-for-evolving-needs/

The proposed tariff revisions allowing PJM TOs to elect to fund these Network Upgrades, and to earn on a return on them in rate base, helps address these problems.

Q: DOES THIS CONCLUDE YOUR AFFIDAVIT?

A: Yes.

Attachment CRA-1

David Hunger

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MS, Economics
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David Hunger is Vice President with the Energy Practice of CRA. Formerly a senior economist at the Federal Energy Regulatory Commission, Dr. Hunger is an expert in energy market merger analysis and market-based rate matters, as well as energy and capacity market rules in the FERC-regulated Regional Transmission Organizations. For 14 years at the Commission, he took part in or led analyses involving mergers and other corporate transactions, market power in market-based rates cases, affiliate transactions, investigations of market manipulation in electricity and natural gas markets, demand response compensation, compliance cases for capacity and energy market rules in Regional Transmission Organizations (RTOs), merchant transmission, and competition issues in electricity markets. Since leaving the Commission and joining CRA in 2013, he has testified in multiple Commission proceedings involving organized capacity markets administered by RTOs; as well as merger and market-power cases at the state and federal level.

Experience

2013 - Present *Vice President*, Charles River Associates – Energy Practice

1999 - 2013 Federal Energy Regulatory Commission

1999 - 2000 *Economist*, Office of Economic Policy

2000 - 2002 *Economist*, Office of Markets, Tariffs, and Rates - Division of Corporate Applications

2002 - 2003 *Economist*, Office of Market Oversight and Investigations

2003 - 2007 *Senior Economist*, Office of Energy Market Regulation – West Division

2007-2009 *Supervisory Energy Industry Analyst* - Office of Energy Market Regulation – West Division

2009 - 2010 *Deputy Director*, Office of Energy Market Regulation – West Division

2010 - 2013 *Senior Economist*, Office of Energy Policy and Innovation

Dr. Hunger was the technical lead on FERC Order No. 707 (Affiliate Transactions, 2007); Supplemental Merger Policy Statement (2007); and Order No. 745 (Demand Response Compensation, 2012). In addition, Dr. Hunger worked on market design issues in each of the FERC-regulated RTOs.

2001–2014	*Affiliated Professor*, Georgetown University, Graduate Public Policy Institute Classes taught: Microeconomic Theory, Energy Policy, and Master's Thesis advising.
2012 –2014	*Adjunct Professor*, Penn State University, Energy Business and Finance – Energy and Environmental Economics
2000–2001	*Adjunct Assistant Professor of Economics,* American University. Classes taught: Principles of Microeconomics and Principles of Macroeconomics
1998–1999	*Assistant Professor of Economics*, Oglethorpe University. Classes taught: Managerial Economics and International Economics (MBA); Principles of Economics, Intermediate Microeconomics, Macroeconomics, International Economics and Industrial Organization (undergraduate)
1994–1998	*Graduate Teaching Fellow*, Department of Economics, University of Oregon Classes taught: Econometrics, Industrial Organization, and Principles of Microeconomics

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NorthWestern Corporation, Docket No. ER11-1858-009, Market-Based Rates for the Western Energy Imbalance Market filing, before the Federal Energy Regulatory Commission. November 19, 2020.

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Hartree Partners, Docket No. ER17-194-004, Market Power Update for the Southwest and Southeast regions, before the Federal Energy Regulatory Commission. October 30, 2019.

NorthWestern Corporation, Docket No. ER11-1858-008, Triennial Market Power Update, before the Federal Energy Regulatory Commission. June 28, 2019.

Nevada Power, et al., Docket Nos. ER10-2475, et al. Triennial Market Power Update, before the Federal Energy Regulatory Commission. June 28, 2019.

BHE Renewables, Docket No. ER10-2498, Triennial Market Power Update, before the Federal Energy Regulatory Commission. June 28, 2019.

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Adelanto Solar, LLC, et al., Docket Nos. ER15-1883 et al., Notice of Change in Status for the NextEra Market-Based Rates Sellers before the Federal Energy Regulatory Commission. January 31, 2019.

Arizona Public Service Company, Docket No. ER10-2437, Triennial Market Power Update, before the Federal Energy Regulatory Commission. December 28, 2018.

PJM Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, Docket No. ER19-105-000, Affidavit on behalf of FirstEnergy Service Company in support of Comments, before the Federal Energy Regulatory Commission. November 19, 2018.

PJM Minimum Offer Price Rule Proceeding, Docket Nos. EL18-178-000, et al. Affidavit on behalf of American Electric Power Service Corporation and FirstEnergy Utility Companies in support of Reply Comments, before the Federal Energy Regulatory Commission. November 6, 2018.

Joint Application of Dominion Energy, Inc. and SCANA Corporation to Engage in a Business Combination Transaction - Responses to Commission Questions Docket Nos. E-22, Sub 551 and G-5, Sub 585 before the North Carolina Utilities Commission. October 31, 2018.

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Arizona Public Service Company. Application for Market Based Rates Authorization in the CAISO Energy Imbalance Market, before the Federal Energy Regulatory Commission. Docket No. ER18-2000-000, July 11, 2018.

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Limited and Sub-Annual DR Resources filing submitted by PJM Interconnection, L.L.C. Docket No. ER14-504-000. Affidavit in support of Reply Comments by American Electric Power, Duke Energy Ohio, FirstEnergy Corp, Dayton Power & Light, East Kentucky Electric Cooperative, and PPL Companies before the Federal Energy Regulatory Commission, January, 2014.

Capacity Imports Filing submitted by PJM Interconnection, L.L.C. Docket No. ER14-503-000. Affidavit in support of Reply Comments by American Electric Power, Duke Energy Ohio, FirstEnergy Corp., Dayton Power & Light, East Kentucky Electric Cooperative, and PPL Companies before the Federal Energy Regulatory Commission, January, 2014.

Limited and Sub-Annual DR Resources filing submitted by PJM Interconnection, L.L.C. Docket No. ER14-504-000. Affidavit in support of filing by American Electric Power, Duke Energy Ohio, FirstEnergy Corp, Dayton Power & Light, East Kentucky Electric Cooperative, and PP Companies before the Federal Energy Regulatory Commission, December, 2013.

Capacity Imports Filing submitted by PJM Interconnection, L.L.C. Docket No. ER14-503-000. Affidavit in support of filing by American Electric Power, Duke Energy Ohio, FirstEnergy Corp., Dayton Power & Light, East Kentucky Electric Cooperative, and PPL Companies before the Federal Energy Regulatory Commission, December, 2013.

Demand Response Sell Offer Plan Filing submitted by PJM Interconnection, L.L.C. Docket No. ER13-2108-000. Affidavit in support of filing by American Electric Power, Duke Energy Ohio, FirstEnergy Corp., and Dayton Power & Light before the Federal Energy Regulatory Commission, December, 2013.

In the Matter of PJM Up-to Congestion Transactions, Federal Energy Regulatory Commission Docket Nos. IN10-5-000 and IN15-3-000, Affidavit on Behalf of Powhatan Energy Fund regarding claims of market manipulation, October, 2013.

Reports and Publications

Assessment of FRR Alternatives: Considerations for New Jersey. Prepared for Jersey Central Power & Light, submitted at the New Jersey Board of Public Utilities, November 23, 2020.

PJM's Capacity Market: Where are we now? with Jordan Kwok, Pat Augustine and Jeff Plewes. CRA Insights: Energy. October 2020.

"Market Based Rates in the Western Energy Imbalance and Extended Day-Ahead Markets" with Edo Macan, Goran Vojvodic, and Alexia Dupuis. Energy Bar Association Brief. Fall 2020, Vol. 1, Issue 2.

"Offer Behaviour Guidelines Prior to the Implementation of a Capacity Market". Prepared for the Alberta Market Surveillance Administrator, with Jordan Kwok, Chris Russo and Adonis Yatchew. December 7, 2018.

"Economic Evidence of Market Power and Market Manipulation in Energy Markets" with Robin Cohen, Brian Rivard and Christopher Russo. In Global Competition Review: *The Guide to Energy Market Manipulation,* 2018.

"Market Power Analysis of Proposed Transaction between Dominion Energy, Inc. and SCANA Corporation". Prepared for the North Carolina Utilities Commission. January 24, 2018.

"A Case Study in Capacity Market Design and Considerations for Alberta". Prepared for the Alberta Electric System Operator. March 30, 2017.

"The Economic Fundamentals of Capacity Markets". Prepared for the Alberta Electric System Operator. June 2, 2017.

"FERC Clarifies its Methodology for Merger and Market-Based Rates Review", with Edo Macan. *Law360*, May, 2016

"Analyzing Gas and Electric Convergence Mergers: A Supply Curve is Worth a Thousand Words." *Journal of Regulatory Economics*, vol. 24, no. 2, 2003, pp. 161-173

"Determining the Competitiveness of Wholesale Electricity Markets: It Starts with Defining the Markets." In *Markets, Pricing and Deregulation of Utilities*. Michael Crew and Joseph Schuh, eds. Kluwer Academic Publishers, 2002.

Presentations

Market Power Analysis and Transmission Availability in the Western Energy Imbalance and Day-Ahead Markets, Joint CREPC-WIRAB Meeting. San Diego, CA. October 8, 2019.

Current Events Affecting CAISO's Energy, Ancillary Services and Energy Imbalance Market Gulf Coast Power Association 33rd Annual Spring Conference & Exhibition. Houston, TX. April 16, 2019

Are State policies detrimental to competitive electricity capacity markets in theory, in fact, or in your dreams? Mid-Atlantic Conference of Regulatory Utilities Commissioners, 23rd Annual Education Conference, Hershey, PA. June 26, 2018.

Grid Resilience: A Problem in Search of a Solution, or a Solution in Search of a Problem? Harvard Electricity Policy Group Eighty-ninth Plenary Session Thursday, Palm Beach, FL, January 25, 2018.

The Role of Demand Response in Wholesale Energy, Capacity, and Ancillary Services Markets. IEEE Power and Energy Society Meeting, Boston, MA, July 20, 2016.

FERC Order No. 745 is Here to Stay: The Role of Demand Response in Wholesale Energy, Capacity, and Ancillary Services Markets. Utility Variable-Generation Integration Group, Spring Technical Workshop, Sacramento, CA, April 27, 2016.

Outlook on Capacity Markets: The Road to Clarity and Transparency. Platts Northeast Power and Gas Markets Conference. New York, NY. May 2014.

Demand Response at FERC. EPRI Workshop. Houston, TX. August 12, 2012

"Demand Response Compensation." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 21st Annual Western Conference, Monterey, CA, June 2010.

"The Role of Sector-Specific Regulators in Merger Review." American Bar Association 2009 Fall Forum, November 2009.

"Developing a Sustainable Energy Policy." Georgetown Public Policy Institute Policy Conference Washington, DC, February 2007.

"Fixing the Natural Gas Price Indices." US Department of Energy, Electricity Working Group, Washington, DC, March 2005.

"Re-bundling in the Electric Power Industry." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 23rd Annual Conference, Skytop, PA, May 2004.

"Manipulation of Natural Gas Price Indexes: Causes, Effects and Solutions." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 22nd Annual Conference, Skytop, PA, May 2003.

"The Role of Economics and Economists at the FERC." Federal Energy Regulatory Commission, Briefing for Indiana University of Pennsylvania, Economics Department, Washington, DC, September 2002.

"Defining Wholesale Electricity Markets." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 21st Annual Conference, Newport, RI, May 2002.

"Markets, Pricing and Deregulation of Utilities." Rutgers University Research Seminar, Newark, NJ, May 2002.

"How FERC Analyzes Markets." Federal Energy Regulatory Commission, Briefing for Indiana University of Pennsylvania, Economics Department, Washington, DC, October 2001.

"Briefing on Competitive Analysis for the State Development Planning Commission of the People's Republic of China." Federal Energy Regulatory Commission, Washington, DC, May 2001.

"Electric Utility Mergers Involving Generation and Transmission: It Takes Ability and Incentive." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 20th Annual Conference, Tamiment, PA, May 2001.

"Natural Gas and Electricity Mergers: Vertical Restraints or Vertical Market Power." US Department of Energy, Electricity Working Group, Washington, DC, October 2000.

"Vertical Merger Review at the Federal Energy Regulatory Commission." International Association for Energy Economics, 21st Annual Conference, Philadelphia, PA, September 2000.

"Gas and Electric Convergence Mergers: A Supply Curve is Worth a Thousand Words." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 19th Annual Conference, Lake George, NY, May 2000.

"Pollution Regulation in a Model of International Trade." Northwest Conference for Environmental Economics, Eugene, OR, May 1999.

"The Adoption of Energy-Saving Technologies in the Electricity Industry." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 17th Annual Conference, Vergennes, VT, May 1998.

"Entry Decisions and Regulatory Distortions in the Electric Power Industry." Advanced Workshop in Regulation and Competition, Rutgers University Center for Research in Regulated Industries, 16th Annual Conference, Lake George, NY, May 1997.

"Entry of Non-Utility Generators in the Northwest." Pacific Northwest Regional Economic Conference, Spokane, WA, April 1997.

Awards and Associations

Vice Chair, Energy Professional Council, Energy Bar Association 2020 - pres.

Ontario Independent Electricity System Operator - Economist and Advanced Electricity Market Trading Conduct Expert, 2017- pres.

Charitable Foundation of the Energy Bar Association – Board Member 2016 - 2019

Law360 Energy Editorial Advisory Board, 2014

Journal of Regulatory Economics – reviewer

Energy Economics – reviewer

Energy Journal - reviewer

University of Oregon - Outstanding Graduate Teaching Award, 1998

Official Scorekeeper – Oglethorpe University Women's Basketball 1998-1999

Member, Energy Bar Association

Attachment CRA-2

Seabron Adamson

Vice President

MA, Economics
Boston University

MS, Technology and Policy
Massachusetts Institute of Technology

MS, Applied Physics
Georgia Institute of Technology

BS, Physics
Georgia Institute of Technology

Seabron Adamson is a Vice President with the Energy Practice of CRA and leads the global energy disputes and regulatory segment. He was previously an analyst for a major alternative investment firm, and re-joined CRA in 2014.

Mr. Adamson also has significant experience in energy regulation and litigation matters, in North America, the European Union and other countries. Seabron has testified in international arbitration proceedings regarding energy sector disputes in Europe, Latin America, Asia, Canada and other countries. He has provided expert testimony and reports before the Federal Energy Regulatory Commission, the Ontario Energy Board, and a state public utility commission, as well as in Federal and State court proceedings.

Mr. Adamson has worked extensively on electric transmission and regulatory matters, including issues associated with the interconnection of new generation projects. He has also advised extensively on the economics and financing of renewable energy projects in the United States and other countries, including solar projects. This has included work for a wide range of clients.

Prior to joining CRA the first time in 2008, he was a Director of Tabors Caramanis & Associates. He previously held various roles at two other economic consulting firms.

Mr. Adamson has served as an adjunct lecturer at the A.B Freeman School of Business at Tulane University, where he has taught classes on energy trading, risk and portfolio management. He currently teaches a class in the finance department of the Carroll School of Management at Boston College on renewable energy investment and project finance. He is the co-author of a textbook (with S. Raikar) on renewable energy project finance titled *Renewable Energy Project Finance: Theory and Practice* from the Academic Press., He has also published papers in peer-reviewed publications on energy markets, regulation and investment.

Experience

2012 - Present *Senior Consultant and currently Vice President*, Charles River Associates – Energy Practice

2017 – Present	*Part-time Lecturer,* Department of Finance, Carroll School of Management, Boston College
2012 - Present	*Co-founder and current CFO,* Quantum Diamond Technologies Inc.
2008 - 2010	*Analyst (Energy and Commodities)*, Tudor Investment Corporation. Later worked as consultant to Tudor.
2004–2008	*Vice President* (and Co-Head, Energy and Environment Practice), Charles River Associates, Boston, MA.
2003 - 2004	Director, Tabors Caramanis & Associates.
1999 - 2003	Founder and President, Frontier Economics Inc. Co-founder of Frontier Economics Group, an international economics consulting firm with offices in Cambridge, MA, London, UK and Melbourne, Australia.
1996 -1999	President, London Economics Inc. Started US subsidiary of European economic consulting firm.
1992 – 1996	Consultant, Senior Consultant and Managing Consultant, London Economics Ltd. (UK).
1990 – 1992	Research Assistant, Massachusetts Institute of Technology. Research on carbon reduction strategies for the US power industry sponsored by U.S. EPA and EPRI.
1988 –1990	Research engineer, Itek Optical Systems.

Selected Testimony (last 10 years)

Expert report in ICC arbitration regarding the development and financing of a utility-scale solar power project in Asia.

Liability and damages expert on behalf of project lender and lessor (Bank Santander) with respect to a wind farm project in *Punta Lima, LLC and Punta Lima Wind Farm LLC vs. Punta Lima Development Company, LLC*, Case No: 3:19-cv-01673-SCC and 3:19-cv-01800-SCC. Federal District Court for the District of Puerto Rico, (2019-20).

Damages expert in Minnesota state court case between a leading solar generation company and a solar project developer in *Cypress Creek Renewables Development, LLC vs. SunShare, LLC* et al. Case No: 27-CV-18-14955. State of Minnesota District Court, 2019.

Lead energy industry expert in *In re: Appraisal of Columbia Pipeline Group, Inc.,* Cons. C.A. No. 12736-VCL, Court of Chancery of the State of Delaware (2018).

Damages expert on behalf of plaintiff in *Elmrock Master Opportunity Fund I, L.P. v. Citicorp North America, Inc., ESSL 2 Inc. and Citigroup, Inc.*, Supreme Court of the State of New York, County of New York, 2017-18.

Economic expert in dispute regarding an oil and products services and logistics company (*LCT Capital LLC v. NGL Energy LP and NGL Energy Holdings LLC*), Delaware Superior Court, 2017-18.

Damages expert in a major international arbitration dispute between a Middle Eastern national natural gas company and an international energy company regarding damages in the LNG sector, Cairo Regional Center for International Arbitration, 2018.

Affidavit of Seabron C. Adamson in support of the NRG Companies with respect to gas-electric issues in the CAISO in Dockets ER14-1142, ER14-1140 and ER14-1128.

Expert Report of Seabron Adamson and Jeff Plewes for Dayton Power and Light before the Public Utility Commission of Ohio regarding Fair Market Valuation of Ohio Solar Renewable Energy Credits, July 2014.

Expert report and oral testimony in NAFTA Chapter 11 arbitration (*Mesa Power LLC v. Government of Canada)* regarding wind and solar energy in Ontario under UNCITRAL rules.

Expert testimony in proceeding before the Régie de l'énergie (Québec) on behalf of Newfoundland and Labrador Hydro regarding the transmission upgrades policy of Hydro Québec TransÉnergie, Demande R-3888-2014.

Expert testimony before Québec arbitration tribunal regarding electricity supply contracts.

Expert for the defendant in *Barton Windpower LLC and Buffalo Ridge I LLC v. Northern Indiana Public Service Company,* Civil Action No. 13-CV-05329, United States District Court for the Northern District of Illinois Eastern Division, 2015.

Lead gas price expert for the Official Committee of the Unsecured Creditors *in re: Energy Futures Holdings Corp., et. al.*, Case 14-10979 (CSS), U.S. Bankruptcy Court for the District of Delaware (testimony not filed).

Expert Report of Seabron Adamson and Edo Macan on Behalf of *Lori Sanborn and Other Class Action Plaintiffs v. Viridian Energy,* Class Action Complaint No. 3:14-CV1731 (SRU), U.S. District Court - District of Connecticut, (with Edo Macan), April 1, 2016.

Expert Class Certification Report on Behalf of *Shane C. Roberts and Other Class Action Plaintiffs v. Verde Energy USA Inc.*, Docket No. X07HHDCV15-6060160-S, Complex Litigation Docket at Hartford – Connecticut Superior Court, (with Edo Macan), May 2, 2016.

Settlement Expert Report on Behalf of *Holly Chandler and Other Class Action Plaintiffs v. Discount Power, Inc.*, Docket No. X03-HHD-CV14-6055537-S, Complex Litigation Docket at Hartford - Connecticut Superior Court, (with Edo Macan), May 16, 2016.

Expert Report on Behalf of *Gary W. Richards and Other Class Action Plaintiffs v. Direct Energy Services,* LLC, Class Action Complaint No. 3:14-CV-1724 (SRU), U.S. District Court - District of Connecticut, (with Edo Macan), May 27, 2016.

Rebuttal Report on Behalf of *Gary W. Richards and Other Class Action Plaintiffs v. Direct Energy Services, LLC*, Class Action Complaint No. 3:14-CV-1724 (SRU), U.S. District Court - District of Connecticut, (with Edo Macan), November 10, 2016.

Expert Class Certification Report of Seabron Adamson and Edo Macan on Behalf of *Niko and Constance Jurich and Other Class Action Plaintiffs v. Verde Energy (USA) Inc.* Complex Litigation Docket at Hartford – Connecticut Superior Court, January 27, 2017. Also Supplemental Expert Report (with Edo Macan) on November 8, 2017.

Expert Report of Seabron Adamson and Edo Macan on Behalf of *Lydia Gruber and Louise Ferdinand and Other Class Action Plaintiffs v. Starion Energy, Inc.*, Class Action Complaint No. 3:14-CV-1828 (SRU), U.S. District Court - District of Connecticut, July 29, 2016.

Publications

Book
S. Raikar and S. Adamson, *Renewable Energy Finance: Theory and Practice*, Academic Press - Elsevier, 2020.

Book Chapters
S, Adamson, D. Hernandez and H. Rakebrand, "The Coordination of Gas and Electricity Network Investment Decisions", in *Transmission Network Investment in Liberalized Power Markets,* M. R. Hesamzadeh, J. Rosellón and I. Vogelsang, eds., Springer, 2020.

S. Adamson and G Parker, "Participation and Efficiency in the New York Financial Transmission Rights Markets", chapter in *Financial Transmission Rights: Analysis, Experience and Prospects*, J. Rosellón and T. Kristiansen, eds., Springer, 2013.

S. Adamson, R. Laslett, R. Bates and A. Pototschnig, *Market-Based Control of Air Pollution in Krakow, Poland: Can Economic Incentives Help?* World Bank Technical Paper Series (No. 308), 1994.

Academic Publications

S. Adamson, "Comparing Interstate Regulation and Investment in US Electric and Gas Transmission", *Economics of Energy and Environmental Policy*, Volume 7, No. 1, 2018.

S. Adamson, T. Noe and G. Parker, "Efficiency of Financial Transmission Rights Markets in Centrally Coordinated Periodic Auctions", *Energy Economics*, Vol. 32, No. 4, 2010.

S. Adamson and R. Tabors, "Pricing Short-term Gas Availability in Power Markets", *Growing Concerns, Possible Solutions: The Interdependency of Natural Gas and Electricity Systems*, MIT Energy Initiative, April 2013.

S. Adamson and S. Englander, "Efficiency of New York Transmission Congestion Contract Auctions", *Proceedings of the 38th Annual Hawaii International Conference on System Sciences*, 2005.

R. Tabors and S. Adamson, "Price Discrimination in Organized/Centralized Electric Power Markets", *Proceedings of the 39th Annual Hawaii International Conference on System Sciences*, 2006

R. Stoddard and S. Adamson, "Comparing Capacity Market and Payment Designs for Ensuring Supply Adequacy", *Proceedings of the 42th Annual Hawaii International Conference on System Sciences*, 2009.

S. Adamson and A. Sagar, "Managing Climate Risks through a Tradable Contingent Securities Approach", *Energy Policy*, January 2002.

S. Adamson and A.J. Goulding, "The ABCs of Market Power Mitigation: Use of Auctioned Biddable Contracts to Enhance Competition in Generation Markets", *The Electricity Journal*, December, 1998.

S. Schnittger and S. Adamson, "Retail Competition in Electricity – Market Prices Revisited", *The Electricity Journal*, July 2001.

Major Academic Conference Papers/Presentations

S. Adamson, Plenary Session Presentation, International Association for Energy Economics Annual Conference, Singapore, 2017.

R. Green, S, Adamson and S. Littlechild, "Competitive Benchmarks in Electricity Markets", paper presented at the IDEI Conference "Competition and Coordination in the Electricity Industry, Toulouse 2004.

S, Adamson and K. Wellenius, "Determination of Horizontal Market Power Abuse in Wholesale Electricity Markets", paper presented at the POWER conference, University of California at Berkeley, 2000.

S. Adamson and G. Parker, "Productivity and Technological Change in Shale Gas Production: An Econometric Analysis of Well Data from the Haynesville Shale", paper presented at the International Association of Energy Economics international conference, Stockholm, June 2011.

Attachment CRA-3

Documents Relied on Regarding Federal and State Energy Policies

U.S. Dept. of Energy. (2021, March 29). Energy Secretary Granholm Announces Ambitious New 30 GW Offshore Wind Deployment Target by 2030 [Press release].

U.S. White House. (2021, April 22). FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies [Press release].

U.S. White House. (2021, March 31). FACT SHEET: The American Jobs Plan [Press release].

Internal Revenue Code § 45 (2021)

Delaware Legis. Climate Framework for Delaware, Prepared under Executive Order 41, 2014.

D.C. Executive Office of the Mayor. (2017, December 4). Washington, DC to Reduce Greenhouse Gas Emissions by 100 Percent by 2050 [Press release].

Maryland General Assembly, S.B. 323 (2016).

Michigan Executive Order No. 2020-10 (Sep. 23, 2020)

New Jersey Executive Order No. 54 (Feb. 13, 2007)

North Carolina Executive Order No. 80 (Oct. 29, 2018)

Pennsylvania Executive Order No. 2019-01 (Jan. 8, 2019)

Virginia Code Ann. § 94 (2020).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Transmission Owners	**)**	**Docket No. ER21-_______**

AFFIDAVIT OF DAVID HUNGER

I, David Hunger, under the penalty of perjury, state that the information contained in the Affidavit of David Hunger and Seabron Adamson on behalf of the PJM Transmission Owners is true, correct, accurate, and complete to the best of my knowledge, information and belief.

Executed this 25th day of June, 2021.

____
David Hunger

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Transmission Owners) **Docket No. ER21-_______**

AFFIDAVIT OF SEABRON ADAMSON

I, Seabron Adamson, under the penalty of perjury, state that the information contained in the Affidavit of David Hunger and Seabron Adamson on behalf of the PJM Transmission Owners is true, correct, accurate, and complete to the best of my knowledge, information and belief.

Executed this 25th day of June, 2021.

____
Seabron Adamson

ATTACHMENT E

Example of the Formula Rate Charge Calculations under the NUFA
(Provided as an Excel File)

Line			
1	**PJM TO @ 21% FIT**		
2	**Schedule B**		
3			
4	**Levelized Fixed Charge Rate Calculation with Deferred Recovery**		
5	**(Populated Template)**		
6			
7	Project Name:	2021 Network Upgrade project	
8			
9	Description	2021 Network Upgrade project	
10			
11	Cost Year:	2020 Actual True-up	
12			
13	Estimated or Actual Cost and ISD:	Actual cost; Actual ISD 6/1/2021	
14			
15	Rate Recovery Period:	June 1, 2021 thru May 31, 2022	
16			
17	Levelized Fixed Charge Computation:		
18			
19	Initial Network Upgrade Capital Cost		$1,000,000
20	Levelized FCR with Deferred Recovery	(Line 57)	10.4809%
21	Annual Network Upgrade Charge	(Line 19 x Line 20)	$104,809
22	Monthly Payment	(Line 21 / 12)	$8,734
23			
24	Fixed Charge Rate Calculation:		
25			
26	Investment	(Line 19)	1,000,000
27			
28	PW Federal Tax Depreciation	[Line 109, Col (f)]	630,294
29	Applicable federal tax rate	(Line 64)	21.00%
30	PW Federal Tax Benefit	(Line 28 x Line 29)	132,362
31			
32	PW State Tax Depreciation	[Line 109, Col (g)]	630,294
33	Applicable state tax rate	(Line 65)	7.11%
34	PW State Tax Benefit	(Line 32 x Line 33)	44,814
35			
36	PW Tax Benefit	(Line 30 + Line 34)	177,176
37	Present Worth Cashflow	(Line 26 - Line 36)	822,824
38	Revenue Conversion Factor	[1/(1 - Line 63)]	1.3910
39	Present Worth Revenue Requirement	(Line 37 x Line 38)	1,144,560
40			
41	In Service Date		6/1/2021
42	Recovery Start Date		6/1/2021
43	Deferral Days (February counted as 28 days)		0
44	Deferral Annualization Factor (based on 365 days)	(Line 43/365)	0.0000%
45	Discount Rate per Year	(Line 75)	6.6128%
46	Deferral Factor	{[(1+Line 45)^Line 44] - 1}	0.0000%
47	Deferral Adjustment	(Line 39 x Line 46)	0
48			
49	Present Worth with Deferred Recovery	(Line 39 + Line 47)	1,144,560
50			
51	Recovery Period (RP)		20
52	Annualization Factor	{ i [(1+i)^RP]} / {[(1+i)^RP] -1}	9.1571%
53		(where RP is Line 51, and i is Line 45)	
54			
55	Levelized Amount	(Line 49 x Line 52)	104,809
56			
57	Levelized Fixed Charge Rate (FCR)	(Line 55 / Line 26)	10.4809%
58			

Line							
59							
60	Project Name:	2021 Network Upgrade project					
61							
62	Inputs from Formula Rate True-up Filing						
63	Combined Tax Rate			28.11%			
64	Applicable Federal Income Tax Rate			21.00%			
65	Applicable State Income Tax Rate			7.11%			
66							
67							
68	Capital Structure			Amount	Weight	Cost	Weighted Cost
69							
70	Long-Term Debt			4,000,000,000	50.00%	4.00%	2.0000%
71	Preferred Stock			0	0.00%	0.00%	0.0000%
72	Common Equity			4,000,000,000	50.00%	10.35%	5.1750%
73	Total Capitalization			8,000,000,000	100.00%		7.1750%
74							
75	Discount Rate				(Line 73 - (Line 63 x Line 70))		6.6128%
76							
77							
78							
79							
80	MACRS Depreciation Rates with Bonus Depreciation Option:						
81							

Line	(a) Year	(b) MACRS Rates	(c) MACRS Depr	(d) State Depr	(e) Present Worth Factor 1/(1+i)^n	(f) Present Worth Federal Tax Depreciation	(g) Present Worth State Tax Depreciation
87							
88	Base	(Line 19)	$1,000,000	$1,000,000			
89	1	0.00%	0		0.937974	0	
90	Remaining Base	(Line 88-Line 89)	1,000,000.0				
91							
92	1	5.00%	50,000	50,000	0.937974	46,899	46,899
93	2	9.50%	95,000	95,000	0.879795	83,580	83,580
94	3	8.55%	85,500	85,500	0.825224	70,557	70,557
95	4	7.70%	77,000	77,000	0.774039	59,601	59,601
96	5	6.93%	69,300	69,300	0.726028	50,314	50,314
97	6	6.23%	62,300	62,300	0.680995	42,426	42,426
98	7	5.90%	59,000	59,000	0.638755	37,687	37,687
99	8	5.90%	59,000	59,000	0.599136	35,349	35,349
100	9	5.91%	59,100	59,100	0.561974	33,213	33,213
101	10	5.90%	59,000	59,000	0.527116	31,100	31,100
102	11	5.91%	59,100	59,100	0.494421	29,220	29,220
103	12	5.90%	59,000	59,000	0.463754	27,361	27,361
104	13	5.91%	59,100	59,100	0.434989	25,708	25,708
105	14	5.90%	59,000	59,000	0.408008	24,072	24,072
106	15	5.91%	59,100	59,100	0.382701	22,618	22,618
107	16	2.95%	29,500	29,500	0.358964	10,589	10,589
108							
109	Total		1,000,000	1,000,000		630,294	630,294
110							

111 Footnote:

112 *Use Line 89 if bonus depreciation is applicable*

113

Return \ Capitalization Calculations From Transmission Formula Rate True-up Filing

Line or Note			Response	Cap Limit %
	Does the formula rate template include a Capital Structure Equity Limit (Cap)? (Yes or No)		No	

Line or Note		$	Actual %	Cap Limit %	Cost (Note "X")	Weighted	
105	Long Term Debt	4,000,000,000	50.00%	0.00%	0.0400	0.0200	=WCLTD
106	Preferred Stock	0	0.00%	0.00%	0.0000	0.0000	
107	Common Stock	4,000,000,000	50.00%	0.00%	0.1035	0.0518	
	Total Capitalization (Sum Lines 105 to 107)	8,000,000,000				0.0718	=R

Income Tax Rates From Transmission Formula Rate True-up Filing

120	FIT =	21.00%
121	SIT=	9.00%
122	p =	0.00%
	INCOME TAXES	
123	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =	28.11%

Notes:

X Note in formula rate template applicable to Allowed ROE.

ATTACHMENT F

Copy of PJM Transmission Owners' April 27, 2021 Presentation to PJM Stakeholders

PJM Transmission Owners’ Proposal Regarding TO-Funding of Network Upgrades

Presented to PJM Stakeholders in Accordance with April 16, 2021

Notice of PJM Transmission Owners Consultation with the Members Committee Regarding Proposed Revisions to the PJM Tariff

April 27, 2021

Overview: What We Plan to Address

- Setting the Stage
- Background on PJM and MISO Interconnection Processes
- Why Now?
- Risks Are Real
- Proposed Changes to the PJM Tariff
- Next Steps

Setting the Stage

- Increasing numbers of generators are seeking to interconnect to the PJM transmission system, thereby requiring construction of significant network upgrades to accommodate these requests.
- The PJM TOs actively support efforts to decarbonize the electric power sector and to develop the necessary infrastructure to support interconnection of clean energy resources to the electric grid.
- The current PJM interconnection pricing model requires generators to pay up front for network upgrades and for the transmission owner to own and operate those facilities with no opportunity to earn a return.
- The PJM TOs intend to make a Section 205 filing proposing changes to the PJM Tariff to give them the ability to elect to fund network upgrades and earn a return of, and a return on, the capital of those upgrades.
- The PJM TOs recognize that broader interconnection policy changes are being considered and believe this proposal can complement those efforts.

PJM Interconnection Queue Process

TOs collaborate with PJM and developers to support interconnection of new resources and to support modifications to existing resources, while maintaining the safety and reliability of the grid.

- Coordinate with PJM and developers to address system upgrades necessary to accommodate interconnection of new resources or changes to existing resources.

- Develop network upgrades to address reliability violations and to identify facilities needed for interconnection.

- Execute analytical studies and agreements to ensure the timely construction of necessary network upgrades.

How Network Upgrades are Funded in PJM

- Network upgrades are system modifications to accommodate the interconnection of a new or existing generator while ensuring the reliability of the transmission system.
- Network upgrades are identified by PJM in the Facility Study report.
- Interconnection customer currently funds the construction costs of Network upgrades prior to interconnection service.
  - Network upgrade payments are contributions that go into the PJM TO's transmission rate base at $0 (*i.e.*, the TO earns no return on the network upgrade).
  - The TO is reimbursed for O&M expenses related to network upgrades through transmission rates that paid by PJM transmission customers, *not* by the interconnection customer (the TO again earns no return on the network upgrades).
  - The TO recovers capital and O&M costs but earns no profit on those assets and therefore provides no compensation to investors for the risks the TO is assuming from the ownership of those network upgrades.

Current Treatment of Network Upgrade Costs

Cost	Treatment
Cost of Construction	Interconnection Customer pays
Operation and Maintenance Expense	Transmission Customers pays (annually)
Real Estate Taxes	Transmission Customers pays (annually)
Asset Amount in Transmission Rate Base	$0
Utility Return = (Rate Base of Asset) *(ROR)	($0 *.08)= $0

Funding Network Upgrades in MISO

MISO

- The TOs have the option to fund the network upgrades and earn a return of and on the capital on the network upgrades
- Through this option, the TOs recover their capital costs plus a return over time by assessing a network upgrade charge on the developer.
- The TOs own the network upgrades.

DC Circuit's Rulings

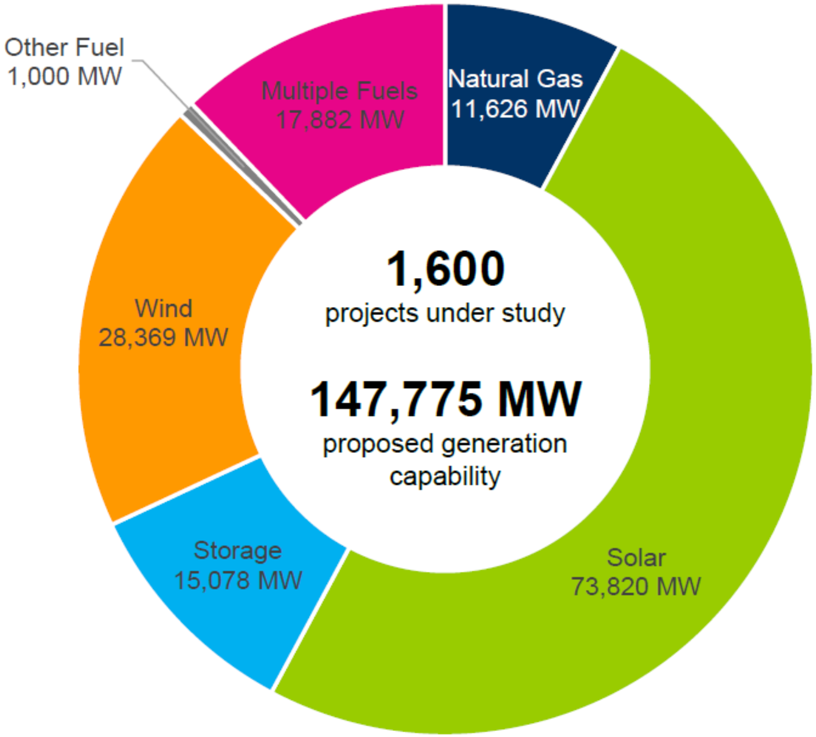
- Prior FERC orders would have required MISO TOs to "act, at least in part, as a non-profit business. . . . Put another way, by modifying the transmission owners' entire enterprise, FERC's orders attack their very business model and thereby create a risk that new capital investment will be deterred."
- MISO TO shareholders should not be "forced to accept incremental exposure to loss with no corresponding benefit."
- If FERC Is going to prevent MISO TOs from electing to fund network upgrades and earn on them, "FERC must explain how investors could be expected to underwrite the prospect of potentially large non-profit appendages with no compensatory incremental return."

Why Now?

- PJM has experienced a sharp increase in the number of generation interconnection requests and MWs connecting to the transmission grid.
- More generator interconnections mean more network upgrades must be built to accommodate them.

PJM October 2020 presentation to stakeholders shows:

- Approximately 1,600 active interconnection projects in PJM queue
- Approximately 150,000 MW with majority being new solar, wind and storage projects
- Currently, there are approximately $6.5 billion of active network upgrades in the PJM regional plan.



Risk to Transmission Owners are Real

- Transmission owners face increased risks for owning and operating the *additional* network upgrade equipment and facilities necessary to accommodate the new generator interconnection requests, and those risks have a growing impact on their core business model.
- Examples of PJM TO Risks associated with owning/operating the additional equipment:
  - **Reliability and cybersecurity risks:** Additional network upgrade equipment presents more exposure to Bulk Electric System (BES) mis-operations and increased system exposure to outages, blackouts, cybersecurity or other reliability and NERC compliance issues.
  - **Safety risks:** Increasing the number of new facilities will result in more construction and ongoing operation and maintenance activities, thereby increasing exposure to safety incidents.
  - **Environmental risks:** Owning and operating network upgrades exposes the PJM TOs to liabilities such as contamination of property, air emissions, and extreme weather events.
  - **Financing risks:** The growing number of system facilities operated without profit impacts the PJM TOs' overall business model. In the DC Circuit's 2018 Ameren decision, the court held: "a utility's return must allow it to compete for funding in financial markets. Investors however invest in enterprises, not just portions thereof."
  - **Litigation risks:** Operating more network upgrades will result in increased exposure to potential accidents or other events, thereby exposing the PJM TOs to uncompensated liability.
- ROE intended to compensate for risks of owning and operating facilities (regulatory compact)

Proposed Changes to the PJM Tariff

- Based on tariff revisions accepted by FERC in MISO, the PJM TOs are proposing similar changes to provide for TO-funding of network upgrades and earn a return of, and a return on, the capital of those upgrades.
  - ✓ The PJM TOs' proposed treatment of network upgrades is similar to the treatment of other transmission projects in PJM.
- Proposed new tariff language includes:
  - ✓ Allowing TOs to exercise option to fund network upgrades
  - ✓ New *pro forma a*greement to establish a standard mechanism and terms for the PJM TOs to recover the costs for the network upgrades from the interconnection customers
  - ✓ Formulaic charge to recover upgrade costs
  - ✓ Financial security requirements for the interconnection customer on upgrade costs, which will decrease over time
  - ✓ Financial security will not overlap with security provided under the ISA

Treatment of Network Upgrade Costs Under Current Model and TO-Funded Proposal

Cost	Current Model	Proposed TO-Funded Election
Cost of Construction	Interconnection Customer pays	Transmission Owner pays
Operation and Maintenance Expense	Transmission Customers pay (annually)	Transmission Customers pay (annually)
Real Estate Taxes	Transmission Customers pay (annually)	Transmission Customers pays (annually)
Capital Cost of Upgrade and Related Costs	$0	Interconnection Customer pays (annually)
Return on Network Upgrade Costs	$0	Interconnection Customer pays (annually)

- Capital costs proposed to be recovered over 20 year period as set forth in Network Upgrade Funding Agreement
- Security under funding agreement to cover the capital cost of the upgraded and reduced annually by payment amount

Transparent Process for Implementing the TO Option to Fund

- Each PJM TO will post on the PJM website a non-binding statement of how it plans to treat network upgrades on its system.
- Each PJM TO shall indicate its intent to self-fund each specific Network Upgrade prior to the completion of the Facilities Study.
- A funding agreement shall be tendered to the Interconnection Customer at the same time the Interconnection Construction Service Agreement is provided.
- Interconnection Customer will have option to request PJM to file the agreement with FERC unexecuted.
- Transmission Owners will post a list of the network upgrades they elect to fund and state whether the entity is an affiliate.

Next Steps

- Notice and consultation with stakeholders (begun)
- Coordinate with PJM to develop Tariff changes and the *pro forma* agreement
- Consider and incorporate stakeholder feedback, where appropriate
- TOA-AC will vote to approve proposed Tariff changes
- FERC filing is expected before end of 2nd quarter