UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

H.A. Wagner LLC Brandon Shores LLC	Docket No. ER24-1787, Docket No. ER24-1790 (not consolidated)

PROTEST AND COMMENTS OF THE MARYLAND OFFICE OF PEOPLE'S COUNSEL AND THE SOUTHERN MARYLAND ELECTRIC COOPERATIVE, INC.

Pursuant to Rule 211 of the Federal Energy Regulatory Commission's (the "Commission") Rules of Practice and Procedure, 18 CFR § 385.211, the Maryland Office of People's Counsel ("OPC") and the Southern Maryland Electric Cooperative, Inc. ("SMECO") (collectively, the "Joint Protestors") respectfully submit the following protest and comments regarding the April 18, 2024 filings of H.A. Wagner LLC ("Wagner") (ER24-1787) and Brandon Shores LLC ("Brandon Shores") (ER24-1790) for individual Continuing Operations Rate Schedules ("CORS") applicable to each of the H.A. Wagner and Brandon Shores power plants (collectively, the "Power Plants").[1]

Wagner and Brandon Shores are affiliated companies wholly owned, through intervening subsidiaries, by Talen, their ultimate parent.[2]

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[1] Combined Notice of Filings (April 18, 2024). The Commission extended the intervention date and protest filing date to May 16, 2024, by order dated May 2, 2024.

[2] Brandon Shores CORS Transmittal Letter at 4; Wagner CORS Transmittal Letter at 4 ("All of the membership interests in Brandon Shores [and Wagner] are held by Raven FS Property Holdings LLC, all of whose membership interests are held by Raven Power Fort Smallwood LLC ('RPFS'). All of the membership interests of RPFS are held by Raven Power Finance LLC, which is wholly owned by Raven Power Generation Holdings LLC ('Raven Holdings'). All of the membership interests of Raven Holdings

The Joint Protestors timely filed doc-less motions to intervene in each of the proceedings docketed as ER24-1787 and ER24-1790.[3] Due to the close and overlapping relation between the separate filings by Wagner and Brandon Shores, the Joint Protestors are filing this protest in both docketed proceedings, addressing the common core of issues raised in each of the filings as well as the particulars of each filing.[4]

Talen (through its wholly owned subsidiaries, Wagner and Brandon Shores) requests Commission approval of the CORS for the Power Plants commencing June 1, 2025. After decades of operating in competitive wholesale power markets under Commission-authorized market-based rate authority ("MBRA"), Talen seeks "cost of service" compensation for both Power Plants through the proposed CORS, ostensibly in accordance with the Open Access Transmission Tariff (the "OATT") of PJM Interconnection LLC, Part V, §§ 113-119 (sometimes referred to below as "PJM

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are held by Talen Generation LLC, which is wholly owned by Talen Energy Supply, LLC ('Talen Energy Supply'). All of the membership interests of Talen Energy Supply are held by Talen, a public corporation traded on the over-the-counter markets under the ticker 'TLNE.'").

[3] Accession No. 20240423-5052 (MPC Intervention in ER24-1787); Accession No. 20240423-5047 (MPC Intervention in ER24-1790 Accession No. 20240423-5005 (SMECO Intervention in ER24-1787); Accession No. 20240423-5209 (SMECO Intervention in ER24-1790).

[4] When references or citations are made herein to a particular filing by either Brandon Shores or Wagner, the filing is referred to in the text as the "Brandon Shores Filing" (for Brandon Shores) and the "Wagner Filing" (for Wagner) and collectively, the "Talen Filings". For simplicity (unless the context requires otherwise, the filing sponsor or power plant will be referred to herein as Talen.

Reliability Service" or as "Reliability Must Run" or "RMR" service[5]), pursuant to section 205 of the Federal Power Act.[6]

Section 205 expressly provides that the rates and charges for the sale of electricity by an applicant "shall be just and reasonable" and that an applicant bears the burden of proof to show that this standard is satisfied.[7] For the reasons described below, Talen's proposed rates and charges for operation of the Power Plants are not "just and reasonable." The Commission should reject Talen's proposed CORS for each of the Power Plants, subject to refiling by Talen to cure those deficiencies, or, if not rejected, put into effect, subject to refund, with the issues raised in this Protest set for hearing and determination by the Commission.

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[5] RMR or "reliability must-run" is a general term used in the electric utility industry to describe roughly similar functions—namely requested service of a generating resource beyond its proposed date for deactivation to avoid grid reliability violations. The function and operation of RMR resources can vary across the different Regional Transmission Organizations such that the term, while useful shorthand, should be considered in the context of the particular RTO under investigation. The PJM OATT does not expressly use the term.

[6] 16 U.S.C. § 824d.

[7] *Id.*, § 205d(a) ("All rates and charges demanded or received by any public utility for or in connection with the… sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable…"); §205d (e)("At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility…."). *See generally*, *Anaheim, et al. v. FERC*, 669 F.2d 799, 809 (D.C. Cir. 1981) ("The Federal Power Act imposes on the Company the 'burden of proof to show that the increased rate of charge is just and reasonable.'") (citing § 205(e)); *Nantahala Power and Light v. FERC*, 727 F.2d 1342, 1351 (4th Cir. 1984) ("A utility bears the burden of justifying each component of a rate increase, and the overall increase itself, under § 205(e)."). The conversion of the Power Plants from operation under MBRA to the CORS sought by Talen comprises a "rate increase" within the meaning of the statute.

INTRODUCTION

On April 6, 2023, Brandon Shores notified PJM that it planned to retire the coal-fired Brandon Shores Units 1 and 2 (approximately 635 MW and 638 MW of nameplate generating capacity, respectively) located near Baltimore, Maryland as of June 1, 2025. PJM issued a notice on June 6, 2023, that grid reliability violations would occur if the Brandon Shores Units 1 and 2 are deactivated as proposed.[8] PJM subsequently identified numerous transmission system upgrades necessary to ensure system reliability in the absence of the Brandon Shores units and filed with the Commission for approval to implement these upgrades. The upgrades are expected to be in commercial operation on or before December 31, 2028.[9]

On October 16, 2023, Wagner notified PJM that it intended to retire Wagner Units 1, 3, 4, and CT 1, also effective June 1, 2025. The Wagner Units are physically adjacent to the Brandon Shores Units. On January 4, 2024, PJM responded to Wagner's notice of proposed deactivation and stated that "the deactivation of the Wagner generating units 3 [oil-fired 305 MW capacity summer rating] and 4 [oil-fired 397 MW capacity summer rating] will adversely affect the reliability of the PJM Transmission [system] absent upgrades to the Transmission system."[10] PJM's response stated that "PJM and the affected Transmission Owners have determined the need for reliability upgrades in the area. These upgrades, when completed in approximately 5 years, will resolve all

[8] Brandon Shores CORS Transmittal Letter at 6–7 (April 18, 2024).

[9] *Id.*

[10] Wagner CORS Transmittal Letter at 6 (April 18, 2024).

reliability issues identified."[11] Similar to its conclusions regarding Brandon Shores Units 1 and 2, PJM concluded that Wagner Units 3 and 4 would be needed to maintain system reliability in the interim while the necessary transmission upgrades are constructed and placed into operation.[12]

Talen accepted PJM's request to provide PJM Reliability Service until the identified transmission solutions are placed into service. A generation owner that accepts such a PJM request has two options under the OATT for cost recovery. A generation owner may "receive the Deactivation Avoidable Cost Credit" ("DACC"), functioning much like a formula rate, prescribed in OATT, Part V, section 114.[13] Alternatively, under section 119, a generation owner "may file with the Commission a cost of service rate to recover the entire cost of operating the generating unit until such time as the generating unit is deactivated pursuant to this Part V (the 'Cost of Service Recovery Rate')."[14] Talen elected to file a cost of service recovery rate, with a requested effective date of June 1, 2025.

Generator owners recover the costs paid for PJM Reliability Service through regulated transmission rates. These rates are paid by the customers in the zones assigned financial responsibility for the grid solutions upgrades required to remedy the reliability

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[11] *Id*.

[12] *Id.* at 3-4.

[13] OATT, Part V, § 114, https://agreements.pjm.com/oatt/3897.

[14] *Id*. § 119.

violations that would result from the proposed deactivations.[15] While some of the grid solutions' cost allocations have been modified following their initial approval and may change again over time, cost allocation to load for the proposed RMRs—and the revenue requirements associated with the grid solutions to replace the RMRs—is currently mapped by PJM's RTEP Baseline project filings and the Commission's approvals of those filings in docket ER23-2612 (the Brandon Shores grid solution filing) and docket ER24-843(the 2022 RTEP Window 3 baseline filing). The majority of the costs of the RMRs for Brandon Shores and Wagner will be allocated to customers in the BGE and Pepco zones. Both zones are predominantly or wholly composed of electric consumers located in Maryland.

Talen's proposed annual and estimated cumulative RMR revenue requirements (referred to below as the "fixed revenue requirement" or "FRR") for the Brandon Shores and Wagner CORS are identified in Table 1 below. The table excludes the costs of on-going capital investments required to keep the plants operating ("Project Improvements" or "PIs") and variable costs related to actual operation.

[15] OATT, Part V, Sec. 120 ("Cost Allocation: The costs incurred to compensate Generation Owners pursuant to this Part V of this Tariff shall be an additional transmission charge allocated to the load in the Zone(s) of the Transmission Owner(s) that will be assigned financial responsibility for the reliability upgrades necessary to alleviate the reliability impact that would result from the Deactivation of the generating unit and this new charge shall be collected monthly from such loads in addition to all other charges for transmission service to such loads.").

Table 1: Annual and Cumulative Costs of RMRs

	Annual FRR	Cumulative FRR over RMR term
Brandon Shores	$175.4 Million[16]	$628.6 Million
Wagner	$40.3 Million[17]	$201.7 Million
Total	$215.8 Million	$830.4 Million
RMR Term assumptions: 6/1/25 to 12/31/28 for Brandon Shores; 6/1/25 to 5/31/30 for Wagner. Does not include upward adjustment to Wagner FRR if Brandon Shores is retired. Totals may vary due to rounding.		

In its filings, Talen asserts it is seeking de-activation because both Power Plants are generally "uneconomic" due to (1) low PJM capacity market prices;[18] (2) higher risk of significant performance penalties for participation in the PJM capacity markets due to the Power Plants' relatively long start-up and shut-down times and generally restrictive operating parameters; (3) for Wagner, energy market bid capping asserted to be inconsistent with the plant's permit operating limits; and (4) for Brandon Shores, the anticipated inability to recover the costs of capital expenditures needed to convert the plant to operation on oil.[19]

Not mentioned in the Talen Filings, however, are (1) Talen's recent bankruptcy in 2022; (2) Talen's declaration of its intent to make a very substantial return of capital payment to its new shareholders upon the company's emergence from bankruptcy in

[16] Brandon Shores Filing, Exhibit No. BSH-003 at 1.

[17] Wagner Filing, Exhibit No. WAG-003 at 1.

[18] Talen's assessment of capacity market prices is based on capacity market delivery years ending before the proposed deactivation date.

[19] Brandon Shores CORS Transmittal Letter at 3; Wagner CORS Transmittal Letter at 3.

2023;[20] and (3) the anticipated extended period of RMR operation at rates of compensation in excess of PJM capacity market prices with no or minimal performance risks. While going unmentioned in its filing, these three considerations impacted and are reflected in the decision-making underlying Talen's RMR proposals.

Talen's Filings for the provision of PJM Reliability Service by the Brandon Shores and Wagner Power Plants present an important set of trade-offs. The continuing operation of the Power Plants under PJM Reliability Service is necessary to maintain the reliability of the grid, but the cost paid by ratepayers should not be inflated, nor should the terms and conditions for providing the service be deficient so as to reduce the assurance of its performance. The Commission's resolution must result in just and reasonable rates.

Talen's proposed CORS are not just and reasonable. They contain improper and excessive levels of recovery due to, among other matters, mis-stated and inflated rate base, rate of return and return on equity. If approved as proposed, the proposed rates would confer a windfall on Talen, create a precedent for an undue incentive for other early retirements by existing generation in the PJM footprint, and undermine the financial and competitive position of other generators continuing to participate in PJM's competitive power markets. Furthermore, the terms and conditions of Talen's proposed CORS are seriously deficient, providing little or no assurance of performance by Talen.

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[20] *Talen Energy Announces an Equity Buyback of $300M Worth of its Shares*, ENERGY CENTRAL (Oct. 24, 2023), https://energycentral.com/news/talen-energy-announces-equity-buyback-300m-worth-its-shares ("Given our ample free cash flow and limited need for go-forward growth capex, we believe implementing a shareholder return program is an appropriate part of our overall capital allocation plan," said Mac McFarland, President and Chief Executive Officer. "This share repurchase program demonstrates our commitment to disciplined capital allocation, including prioritizing the return of capital to our shareholders.").

Finally, the Talen filings are wholly deficient and lack the documentation and support required to satisfy Talen's burden of proof in seeking approval from the Commission of its rates. For the Commission to properly address the trade-offs inherent in the Talen filings, the Commission must reject Talen's inflated requested rates and establish terms and conditions that better assure performance of PJM Reliability Service, consistent with the Joint Protestors' arguments set forth below.

DEFICIENCIES IN THE TALEN FILINGS

I. To be just and reasonable, the compensation due under the OATT for providing PJM Reliability Service must exclude recovery related to prior "sunk," fully written-off investment not incurred in anticipation of providing that service.

Talen's proposed cost-of-service recovery for PJM Reliability Service would have customers pay Power Plant costs that previously were the subject of large downward adjustments to the "net plant" for the Power Plants, due to prior dispositions and transactions affecting the Power Plant assets or accounting loss impairments under GAAP. Talen seeks to reverse all or a major portion of these downward plant balance adjustments or write-downs to support its requested revenue requirements.[21] Talen's prior sunk investment in the Power Plants—made well in advance of its contemplation of providing PJM Reliability Service and Talen's prior negative adjustments and write-offs

[21] As described further below, the total amounts, timing and context of these loss impairments is not disclosed in the Talen Filing. For purposes of the discussion here, we assume that a material portion of the "rate base" claimed by Talen to support revenue requirements for the Power Plants was affected by these loss impairments. Joint Protestors intend to identify these amounts through discovery if the Commission sets the matter for hearing.

of these investments due to loss impairments—do not relate to the cost of operating under an RMR and should be excluded from the rate base used to establish the Power Plants' revenue requirements under the PJM Reliability Service arrangement.

A. Talen's proposed cost of service is contrary to Commission precedent relating to RMR compensation in PJM.

The Commission has previously set for hearing at least three times the issue of whether prior sunk investments can be included in the RMR resource owner's compensation under PJM's OATT, Part V, sec. 119. In each case, the Commission's final order did not decide the issue.[22] Moreover, the Commission has stated that the treatment of RMR service compensation under parallel provisions of the tariffs of each of the regional transmission organizations can vary, because of the different policies and rules that attach to RMR service in each RTO.[23]

First, in the *GenOn II* case[24] the Commission approved a contested blackbox settlement based on its general rules for approving settlements enunciated in its *Trailblazer* decisions—that is, the Commission found the overall result was just and reasonable, without deciding the merits regarding its individual components—but pivoted

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[22] *NRG Power Marketing LLC*, 179 FERC ¶ 61,156 (May 31, 2022); *GenPower Midwest LLP*, 140 FERC ¶ 61,080 (2012) P 35 (Initial Order); *PSEG Energy Resources and Trade LLC*, 111 FERC ¶ 61,121 (2005) P 22. Final disposition was arrived at through Commission approved "blackbox" settlements of the compensation amounts so the substantive issue was never finally decided.

[23] Permissible ISO/RTO variation for RMR arrangements: *NYISO*, 150 FERC ¶61,116 (2015) at P 12, n. 22 ("[W]e recognize that there may be reasons to allow variations [for RMR arrangements] among RTOs/ISOs, so we will not at this time direct NYISO to adopt any particular mechanism.") (citing *PJM Interconnection, LLC*, 112 FERC ¶ 61,031 at P 21 (2005)).

[24] *GenPower Midwest LLP* ("*GenOn II*"), 149 FERC ¶ 61,218 (2014).

its approval on evidence in an affidavit submitted by the RMR unit owner asserting that the settlement's level of compensation reflected almost complete exclusion of any return on or of prior investment. Specifically, GenOn provided an affidavit calculating the cost-of-service recovery rate with no return of or on net plant as $12.5 million of the $13.2 million settlement total revenue requirement.[25] Emphasizing the importance of this record evidence in its approval of the settlement, FERC stated:

> We find the GenOn Settlement factually is supported by the Stewart Affidavit [the GenOn sponsored affidavit] and is within the range of just and reasonable outcomes…. Because the cost-of-service recovery rate with no return of or return on net plant supports the settlement rate, we find that the contesting parties would be in no worse position under the settlement than if the case were litigated.[26]

In the *GenOn II* order approving the settlement, the Commission also stated in passing—comprising *obiter dicta* at best given the order's reliance on the assertions in the GenOn affidavit—that the generator seeking to provide reliability service "may file for cost-of-service rates with the Commission and seek a rate which would provide for the recovery of fixed costs, including return on and of capital."[27] This permissive language does not constitute an entitlement to recovery of any and all fixed costs.

Second, after the *GenOn II* decision, the Commission set forth a general taxonomy of types of RMR compensation across the different RTOs based on differences in each

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[25] *Id. at* P 34.

[26] *Id.*

[27] *Id.* (citing to an earlier 2005 order (112 FERC ¶ 61,031 (2005)) pre-dating the PJM capacity markets and the full set of rules interacting with PJM's framework for the provision of RMR service and necessary context for interpretation of the issue of RMR compensation).

RTO's RMR regime. More specifically, the Commission stated that if an ISO/RTO's RMR regime is "exclusive and voluntary"—meaning that the RTO/ISO's tariff allows a resource owner to deactivate without the obligation to defer the deactivation and enter RMR service —FERC will allow compensation at a negotiated rate which at a minimum allows for recovery of "going forward costs" but the measure of permissible compensation due to the resource owner is not otherwise dictated.[28]

PJM's framework for RMRs falls within the "voluntary" category in the Commission's taxonomy of RMR regimes. Compared to other RTOs, the PJM tariff affords the generator a comparatively very short period (90 days) to provide notice of its intent to deactivate.[29] It then expressly notes that, so long as the notice obligations are complied with, the generator may still de-activate "[r]egardless of whether the Deactivation of the generating unit would adversely affect the reliability of the Transmission System."[30] The obvious implication is that the PJM tariff's RMR provisions are "voluntary" in nature, falling with the FERC taxonomy of voluntary RMR regimes. This voluntary nature of the PJM RMR "regime" is evident from multiple other distinctions in PJM's RMR regime. The distinctions showing that PJM's regime is voluntary, and not mandatory as for other RTOs, include:

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[28] *See, e.g., NYISO*, 150 FERC ¶ 61,116 (2015) at P 17; *see also NYISO, Order on Compliance and Rehearing*, 155 FERC ¶ 61,076 (2016) at P 84; *MISO*, 148 FERC ¶ 61,057 at P 84 (2014); *CAISO*, 168 FERC ¶ 61,199 at P 84 (2019).

[29] PJM OATT, Part V, sec. 113.3. For instance, MISO's tariff requires generators seeking to deactivate to provide notice at least one year in advance. MISO Tariff, 38.2.7a(i), https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/.

[30] OATT, Part V, sec. 113.2.

- A shorter advance notice requirement for deactivation;
- The lack of coordination of RMR service with the functioning of the capacity market;
- The differences in interaction with the forward period for capacity market procurement (currently collapsed to less than 1 year from the intended 3-year forward period underpinning the design of the overall PJM RPM capacity market construct);
- The lack of a pro forma contract to define consistently the RMR unit's service obligations;
- The risk of hoarding of capacity interconnection rights (CIRs), as uniquely defined in the PJM footprint, by the deactivating resource to deter the entry of new resources to replace the RMR unit; and
- PJM's limited ability devolving to only wires alternatives to deploy facilities to replace RMR units.[31]

These important distinctions and their impacts are uniquely present in the PJM footprint. Among other reasons, the voluntariness of RMR arrangements within PJM, dictates against affording an entitlement to recovery of the prior sunk investment costs of an RMR resource, as Talen seeks here.

B. Talen's effort to recover sunk investments is contrary to public policy and would lead to rates that are not just and reasonable.

Talen's recovery of prior sunk investment runs counter to significant policy concerns and the FPA's requirement that rates be just and reasonable. Such recovery results in an undue windfall for the continued operation of old and polluting fossil-fueled electric power plants. It does this by misapplying and exploiting the gaps and

[31] Several of these differences and their inter-relationship (as well as RMR compensation) are currently under review by PJM in an on-going stakeholder process through its Deactivation Enhancement Senior Task Force ("DESTF").

inconsistencies in rules and regulations applying at the "border" between the competitive wholesale electric generation market and the regulated provision of transmission grid services where the choice of prevailing regulatory regime may be blurred. The opportunity for a windfall recovery for sunk and written off generation investment is also misaligned with the Commission's general preference for avoiding RMR arrangements.[32]

Affording Talen the compensation that it requests would damage the structure and design of the wholesale electric generation market. The possibility of such recovery improperly incents, through an excessive regulated revenue requirement, other generators operating in the competitive market in similar circumstances to seek similar relief by prematurely withdrawing from the competitive generation market, undermining the competitive position of generators remaining in that market. Talen and its predecessor entities have operated the Power Plants for many years in the competitive wholesale electric generation market, taking the benefits—including uncapped profits not tethered to traditional cost of service rates—and fully assuming the risks of that operation.

Talen now seeks to transform the Power Plants into newly minted regulated assets. It proposes recovery of a substantial portion of Talen's prior written-off, sunk investments under cost-of-service principles, as though the Power Plants had never before operated in

[32] *See, e.g., N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116, P 16 (2015), *order on compliance and reh'g*, 155 FERC ¶ 61,076 (2016), *order on compliance and reh'g*, 161 FERC ¶ 61,189 (2017), *order on clarification and reh'g*, 163 FERC ¶ 61,047 (2018); *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 FERC ¶ 61,237 at P 10 (2012). *See Greenleaf Energy Unit 2, LLC*, 172 FERC ¶ 61,111 (2020) (Commissioner Danly, concurring) ("RMR agreements are a product of market failure, and they themselves cause markets to fail. This further failure arises as RMR agreements obscure the market signals that would create incentives for the very development that the markets are intended to deliver. I therefore agree with Commission precedent that RMR agreements should be a measure of last resort").

the competitive wholesale market. Talen seeks to recover these investments from captive ratepayers through transmission-related regulated rates—ignoring all profits it earned during the Power Plants' period of market operations and exploiting the leverage afforded by PJM's finding that operating the Power Plants is necessary to keep the regulated transmission grid from violating reliability criteria. In short, Talen proposes—to the Commission, the affected States, and affected electric consumers—to make the reliability of the electric grid contingent on its windfall of recovery of a substantial and disproportionate quantum of its already written off investment. The Commission cannot and should not endorse this unjust result. The plants can be fully compensated for the costs remaining in service during the RMR period without providing a windfall for sunk investments that Talen had no reasonable expectation to recoup over the years following their reduction due to asset transactions or accounting impairment write-offs.

C. Talen's reliance on the Commission's *Constellation Mystic Power* decision is misplaced.

Talen cites to Commission rulings in the *Constellation Mystic Power* cases for the proposition that prior GAAP loss impairments of the asset providing RMR type service are not recognized for purposes of determining the rate base used to establish the RMR revenue requirements.[33] Talen's reliance on *Constellation Mystic Power* is misplaced.

Constellation Mystic Power can be distinguished from the circumstances of the Talen Filings for at least four reasons. *First*, Mystic Station's RMR arrangement was

[33] *Constellation Mystic Power, LLC*, 164 FERC ¶ 61,022 (July 2018) (initial order), 165 FERC ¶ 61,267 (Dec. 20, 2018) (order accepting agreement, subject to condition and directing briefs), *order on clarification and rehearing*, 172 FERC ¶ 61,044 (July 17, 2020).

pursuant to ISO-NE's— a RMR regime completely different than that of PJM. As described above, the basis for proper compensation for the Power Plants' continued operation can and should vary given the RMR regimes. *Second*, Mystic Station is a newer gas-fired plant with substantial on-going investment value at the time its owner sought cost-of-service recovery. *Third*, unlike the Power Plants, Mystic Station continues to participate fully in the ISO-NE administered capacity and energy markets. *Fourth*, the loss impairments asserted to be applicable to the investment in Mystic Station were taken at a holding company level and affected multiple other investments rather than—as with the Power Plants at issue here—at the plant level. The loss impairments paralleled a substantial write down of plant value that FERC did recognize (on an original cost basis to reflect a deemed arms' length sales transaction, excluding recognition of any "acquisition premium" due to later arms' length sales in excess of prior sales price reductions). The write down recognized by the Commission, duplicating in substantial part the plant's accounting loss impairments, was to match the value set in a sale of the plant in lieu of foreclosure occurring while the plant operated in the market, and asserted to be an arms' length transaction.

II. The Talen Filings fail to support the rate base and rate base-related components of their proposed revenue requirements under the Commission's original cost test and should be rejected.

Even if the Commission decides to recognize recovery of a measure of Talen's prior, "sunk" investment in the Power Plants, it should reject Talen's proposed revenue requirements as inconsistent with the Commission's original cost test for establishing the rate base used to set revenue requirements for a rate-regulated asset. The Talen Filings misconstrue Commission precedent regarding the proper accounting for adjustments of regulated rate base resulting from the multiple dispositions of the Power Plants occurring over the last several decades.

Moreover, Talen fails to satisfy its burden of proving—as required under FPA section 205—its claimed level of rate-base. Other than a general discussion in the sponsoring witness' pre-filed testimony—and conclusory and truncated numerical summaries included in the schedules attached to the witness' testimony—the Talen Filings lack supporting documentation that anchor the Power Plants' gross plant and accumulated depreciation balances and describe how they were specifically adjusted over time to reflect each of these dispositions. These material deficiencies in the Talen Filings alone warrant the Commission's rejection. At a minimum, much greater evidentiary support would be required—including supporting accounting records—for the Commission to determine that the CORS are "just and reasonable."

The Commission has a long-standing policy and practice for setting the cost-of-service "rate base" for recovery "of" and "on" investment in a regulated asset. The usual context involves dispositions of the regulated asset between different owners. The policy equates the rate base to *the lower of*: depreciated or "net" plant investment in the regulated asset; or a cost established by a transaction disposing of the asset with a third-party, reduced thereafter by depreciation that occurs following the disposition. Thus, the Commission has stated:

> It is longstanding Commission policy that, in a cost-of-service ratemaking context, a utility may only earn a return on (and recovery of) the *lesser* of the net original cost of plant or, when plant assets change hands in arms-length transactions, the purchase price of the plant (also known as the "original cost test").[34]

This original cost test—and the "lesser of" adjustments to rate base resulting from asset dispositions it mandates—"should be applied for every change in ownership [of the regulated asset]"[35] notwithstanding that there may have been multiple dispositions of the regulated asset, and not merely on a one-off basis.[36] According to the Commission, this policy advances two important purposes: (1) it "lowers rate base to the level of the actual investment made in the plant by the acquiring investors, which prevents the acquiring investors from earning a return on monies not actually invested";[37] and (2) "[provides] an objective method of valuation without the need for independent assessment of the fair market value of individual acquisitions."[38] The Commission applies the original cost test to merchant generators that enter cost-of-service ratemaking in diverse contexts—

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[34] *Lawrenceburg Power, LLC*, 173 FERC ¶ 61,166 (2020) P 46. *See also, Central Vermont Public Service Corp.*, 120 FERC 61,143, at P 9 (2007) ("[W]hen the amount paid for the asset is less than the depreciated original cost, the negative acquisition adjustment is recorded as part of the accumulated provision for depreciation"); *Constellation Mystic Power LLC*, 165 FERC at P 64 (*Constellation Mystic Power I*), *order on rehearing*, 172 FERC ¶ 61,044, at P 31 (2020) (*Constellation Mystic Power II*), *aff'd*, *Constellation Mystic Power LLC v. FERC*, 45 F.4th 1028 (D.C. Cir. 2022) (affirming the Commission's application of the original cost test recognizing the negative acquisition adjustment from the exchange in lieu of foreclosure).

[35] *Lawrenceburg Power*, 173 FERC at P 47.

[36] *See, e.g.*, *Locus Ridge Gas Co.*, 29 FERC ¶ 61,052 (1984).

[37] *Lawrenceburg Power LLC*, 173 FERC at P 46 (citing to *Constellation Mystic II*, 172 FERC at P 31).

[38] *Mont. Power v. FERC*, 599 F.2d 295, 300 (9th Cir. 1979); *Constellation Mystic Power II v. FERC*, 45 F.4th at 1045; *see Constellation Mystic Power II,* 172 FERC at P 105.

whether due to acquisition by a fully regulated integrated utility or when entering RMR type service.[39]

Talen's witness Schatzki sponsors the asserted "rate base" for each of the Power Plants, but fails to show whether the rate base impact of each disposition of the Power Plants' assets conforms with Commission policy.[40] In his pre-filed testimony accompanying the Talen Filings, he describes the timeline of the various dispositions of the Power Plant assets during their operation under MBRA and his asserted view of the impact of these dispositions on the Power Plants' rate base. Below is a list of the material dispositions of the Power Plants' assets described by Dr. Schatzki and a summary of his characterization of the impact of each transaction:

Table 2 – History of Dispositions of the Power Plants' Assets

Year	Transaction	Reference and Description in Schatzki Testimony
2012	Divestiture of Assets by Constellation to Riverstone Holdings contemporaneous with Constellation/Exelon merger	Exh. BSH-001, p. 14 of 236. Riverstone acquired the Brandon Shores, Crane and Wagner stations for $371 million. A "fair market value" for Brandon Shores, seemingly separate from the other plants and from the acquisition price, witness Schatzki "understands to be $648 million" which is then used as the "appropriate going-forward net book value." *Id.* at 18 of 36.
2015	PPL Generating Assets Merger with Riverstone creating Talen	Witness Schatzki asserts that the net plant amount as of June 1, 2015 (the date of Talen's formation) should be the fair value of an appraisal and not the allocated sale value. Exh. BSH-001 at 8 of 36. He states: "Brandon Shores' 2015 Net Plant [as so established by fair market value] is the relevant starting point under the Original Cost Test…". *Id.* at 10 of 36.
2016	Riverstone Takes Company Private	
2022	Talen Bankruptcy	
2023 (Qtr 1)	GAAP Loss impairment write-down of plant assets	($325 million GAAP loss impairment write down for plant assets). Witness Schatzki rejects any adjustment to the net plant balances due to the GAAP loss impairment write-down. Id., p. 11 of 36.

[39] *PacificCorp.*, 124 FERC ¶ 61,046, at PP 28-31; *Central Vt. Public Serv.*, 120 FERC ¶ 61,143, P 7.

[40] For the Brandon Shores Filing, *see* Exhibit BSH-003; for the Wagner Filing, *see* Exhibit WAG-003.

2023 (Qtr 2)	Talen emergence from bankruptcy.	Witness Schatzki rejects use of "fresh start" accounting to establish the net plant balance due to Talen bankruptcy. *Id.* at p. 11 of 36.

The Talen witness asserts that the 2012 Constellation-Riverstone transaction sale price of the assets (reported to be $371 million) should be rejected and replaced by the 2015 "fair value" determination (reported to be $648 million).[41] According to Dr. Schatzki, the 2012 disposition and sales price should not be used to reset the plants' net plant balance because the transaction was "coerced," despite the fact that the transaction resulted from a sale to an independent third party. Dr. Schatzki provides two reasons for ignoring the sale price: (1) the sale occurred in the context of a required divestiture of generation assets by Constellation to satisfy the Commission's concerns about market power in the electric generating market that were prompted by the Constellation's then-pending merger with Exelon and the settlement of a pending Commission enforcement action against Constellation; and (2) reports from market observers alleging that the sale was underpriced.[42]

Dr. Schatzki's view about the 2012 transaction should be rejected. *First*, the successor owners of the Power Plants following the 2012 transaction invested the

[41] The Talen Filings do not appear to identify or document any capital investments made between 2012 and 2015 or describe the evolution of annual depreciation between the two dates at least as to the Brandon Shores power plant. Other than the citation by Dr. Schatzki to the fair value determination of the plant(s) in 2015, there is no documentary support to these assertions in the Talen Filings. There is also no apparent distinction made or allocation among the plant and depreciation accounts for the Brandon Shores, Wagner, and Crane (the latter acquired at the same time as Wagner and Brandon Shores, located on the opposite side of Baltimore harbor and subsequently retired) power plants during these periods and/or to which assets the 2015 valuation applied.

[42] Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 17–18.

reported 2012 sale price in acquiring the plants. Revaluing the plants' rate base to a later higher fair market value determined through an appraisal creates a windfall for these successor owners wholly unrelated to their investment at the time of acquiring the assets. Avoiding such windfalls is precisely one of the policy rationales discussed *supra* for not allowing such revaluing of the rate base.

Second, the Commission's use of prices from transactions disposing of regulated assets among sophisticated third parties provides a more objective measure than industry "chatter" about possible or alleged "mispricing" to disqualify third party sales from use in applying the original cost test. Moreover, relying on prices from these third-party transactions avoids the potentially extended uncertainty that would ensue from requiring the vetting of the motivations of independent transacting parties for any asset sale which Dr. Schatzki's theory would entail.

Third, in *Constellation Mystic Power*, the Commission recognized that the disposition of a plant to the plant's creditors in lieu of foreclosure satisfied the requirements under the original cost test for a third-party sale sufficient to reduce the plant's rate base to the face value of the cancelled debt.[43] The 2012 Riverstone-Constellation transaction has an equal if not greater indicia of voluntary action by the transacting parties acting independently and should be recognized accordingly.

Fourth, Dr. Schatzki's assertion that the Commission enforcement action against Constellation skewed the sale process so as to disqualify it for purposes of applying the

[43] *Constellation Mystic Power LLC*, 172 FERC ¶ 61,044 at P 112 (2020).

original cost test is belied by the results of the audit of the Constellation enforcement action.[44] The transaction sale price is anchored by the myriad fiduciary and other duties bearing on the decision-makers for the independent third parties on either side. As such, Dr. Schatzki's speculation about mispricing of the transaction is misplaced.

Major portions of the Monthly Fixed Charge ("MFC") amounts Talen seeks to recover under the proposed CORS for each of the Power Plants relate to Talen's asserted compensation for the return "on" and "of" the "net plant" balances the Talen witness claims are associated with each of the Power Plants.[45] To derive these net plant balances, the Talen witness reports the asserted annual evolution in the gross plant and accumulated depreciation balances for each of the plants in a conclusory and summary manner, contained on one page for each of the filings, with annual amounts for Brandon Shores only separately reported by year between 2021 and 2025 and for Wagner from 2001 to

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[44] *See* Department of Energy, Office of Inspector General, Office of Audits and Inspections, *Special Report: Enforcement Activities Conducted by the Federal Energy Regulatory Commission* (Sep. 2015) at 7, https://www.energy.gov/sites/default/files/2015/10/f27/DOE-IG-0947.pdf ("We found no indication that OE [the Office of Enforcement] had considered the merger during its investigation. In fact, we found that OE attorneys involved with this investigation were given specific instructions not to take into account the pending merger during settlement negotiations. We also found that the determination of whether the merger was consistent with the public interest was made by a separate FERC organization, the Office of Energy Market Regulation. During our review of documentation related to the merger, we discovered nothing to suggest that the then-pending Constellation enforcement action played any type of role in the determination that the merger between Constellation and Exelon was consistent with public interest.").

[45] For Brandon Shores, some $99 million or approximately 57% of the claimed annual fixed charge (or "AFC" (12xMFC)) (with Wagner still in operation) of the $175.4 million is based on recovery of the return "on" (and related taxes) and "of" the asserted beginning net plant balance, or rate base, of $476 million. *See* Brandon Shores Filing, Attachment F, Exhibit No. BSH-003, Schedule 1 at 1 (Items B, D and E); Schedule 2, Line 8 (for total rate base). For Wagner, $40 million, or 27% of the AFC, maps to such recovery, based on an asserted rate base of $54.5 million. *See* Wagner Filing, Attachment E, Exhibit No. WAG-003, Schedule 1 at 1 (Items B, D and E); Schedule 2, line 8 (for rate base). An additional amount related to claimed "opportunity cost" associated with the plants' land market value is included in the total claimed AFC for each plant, which is discussed further *infra*.

2024.[46] Wholly lacking in the Talen filings is any documentation showing that the reported information is in conformity with or can be mapped to the requirements of the Commission's Uniform System of Accounts ("USofA") or are otherwise sufficient to cure the Talen witness's erroneous application of the Commission's original cost test described *supra*.

The following table, derived from the cited conclusory sources in the Talen Filings, depicts these amounts:

Table 3					
Talen Filings' Summary (assuming continued operation of both power plants)					
		Brandon Shores	Wagner	Combined	Notes
1	Rate Base	$476,095,677	$54,487,667	$530,583,344	
2	Annual Fixed Charges (AFC)	$175,432,886	$40,343,114	$215,776,000	
3	Rate Base Related AFC (Return, Depreciation, Associated Income Taxes)	$99,170,090	$11,006,950	$110,177,040	Return component excludes returns related to land development and land otherwise in net plant balances; taxes are as reported in filings (includes taxes on return on land development charge)
4	% of AFC related to Rate Base Related Items	56.53%	27.28%	51.06%	= [3]/[2]
5	% of AFC related to Rate Base Related Items including Land Development Premium	59.77%	35.06%	55.15%	
Sources: Derived from Exh. BSH-003, and WAG-003, Schedules 1-3					

[46] For Brandon Shores, see Attachment F, Exhibit No. BSH-003, Schedule 3 (page 3 of 13). The schedule asserts summarily that the opening gross plant and accumulated depreciation amounts (presumably at the beginning of 2021) "are 2020 end of year amounts based on Brandon Shores' accounting records." No further documentation or support for the referenced 2020 end of year amounts is provided. For Wagner, *see* Attachment E, Exhibit WAG-003, Schedule 3, page 3 of 13 (reporting gross plant, accumulated depreciation and net plant balances for each year from 2001 to 2025 (with capital improvements and depreciation "following DOE standards," note 1).

More specifically, the total Plant-in-Service described and calculated by Dr. Schatzki[47] for the Power Plants is flawed and does not reflect the fact that "fair market value" is not the same as "net book value" and that any purchase price of the assets would and should have been reflected at the "net book value" with any amounts of premiums paid or discounts received over/under the net book value recorded as an acquisition adjustment (premium or discount) in FERC Account No. 116, Utility Plant Adjustments. The acquired facility/plant would not be recorded at "fair market value" in the Plant-in-Service to earn a return. The acquiring entity would need to request and receive Commission approval to include any premium acquisition adjustment above "net book value." Talen provides no evidence in its filings that such necessary Commission prior approval was requested or received.

Dr. Schatzki failed to use the lower of the "net book value" or purchase price for the value of the Plant-in-Service upon the Exelon 2012 divestiture nor did he demonstrate that those values were essentially the same. As discussed *supra*, Dr. Schatzki's rationale for adopting his approach—ignoring a transfer of ownership of the Power Plants—to an independent third-party, by speculating about the transaction's context is contrary to Commission's application of the original cost test.[48]

[47] Exhibit WAG-001 (Prepared Direct Testimony of Todd Schatzki on Behalf of H.A. Wagner LLC) ("Schatzki Wagner Direct") at 9:1 – 15:14; Exhibit BSH-001 (Prepared Direct Testimony of Todd Schatzki on Behalf of Brandon Shores LLC) ("Schatzki Brandon Shores Direct") at 8:21 – 18:9. n

[48] Exhibit WAG-001 (Schatzki Wagner Direct) at 12:9 – 13:16; Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 14:1 – 15:12.

Dr. Schatzki has not provided any FERC precedent which would preclude the sale price of the Exelon divestiture of the Power Plants from reflecting the lower of "net book value" or the purchase price. In fact, as discussed above, FERC's application of its "original cost test" dictates this result. It is immaterial whether the Power Plants' base rates, which originally were based on cost-of-service rates, had most recently been largely based on market-based rates. The same FERC policy would be applicable in the determination of the Power Plants' net plant amounts upon the formation of Talen on June 1, 2015. The Brandon Shores Facility should be recorded on the books for ratemaking at the "net book value" or the actual discounted purchase price, whichever is lower, plus any additions since January 1, 2013, when the facility was acquired from Exelon. Furthermore, Dr. Schatzki's discussion of Wagner's net plant and the comparisons[49] are not relevant to what the "net book value" or the actual discounted purchase price was in determining the Gross Plant, Accumulated Depreciation, and Net Plant that should be included in the claimed rate base in this proceeding. Additionally in applying the Commission's "original cost test", Dr. Schatzki's discussion regarding whether a plant has earned market-based rates[50] is not relevant to the determination of the "net book value" of the Power Plants.

Dr. Schatzki has also not provided any supporting workpapers which reflect the determination of the book/tax timing difference of depreciation for the Power Plant assets

[49] Exhibit WAG-001 (Schatzki Wagner Direct) at 12.

[50] Exhibit WAG-001 (Schatzki Wagner Direct) at 141 –15:14; Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 16:20 – 18:9.

would have occurred from the initial acquisition of the Power Plants from Exelon as of January 1, 2013 to Riverstone, including all Property Plant & Equipment additions (if depreciated at the Department of Energy Financial Management Handbook rates by category). Income tax depreciation is accelerated and would always represent an ADIT credit balance as an offset to rate base until such time as the asset were to be fully depreciated under the book straight-line depreciation method under ratemaking. Dr. Schatzki stated that the ADIT would be zero for the Power Plants,[51] inappropriately comparing the accumulated book depreciation for the entire life of the Wagner and Brandon Shores Facilities (hypothetical) accumulated depreciation for the years 2001 through 2012 and 2000 through 2010, respectively, when the facility was not owned by H.A. Wagner LLC or Brandon Shores LLC, with the tax depreciation for the years where the Wagner and Brandon Shores Facilities were owned and included in Talen's Federal Income Tax Return at the income tax accelerated depreciation rates. This is an apples and oranges comparison. The total accumulated depreciation balance which is recorded on the Power Plants' books represents amounts that would have been accrued under the prior owners and not only the accumulated depreciation accrued by Talen since purchase, while the income tax accelerated depreciation and accumulated reserve represents the amounts that were accrued with respect to the Power Plants' assets since January 1,2013.

The Talen Filings are also deficient in that they afford no recognition to the effects of the Talen bankruptcy in 2022. In the most recent prior application for PJM Reliability

[51]Exhibit WAG-001 (Schatzki Wagner Direct), 16:11-26; BSH-001 Exhibit 20:2-17.

Service (Indian River Unit 4 ("IR4"), docket ER22-1539), the applicant's expert witness took the position that "fresh start" accounting—following the bankruptcy involving the generating asset providing PJM reliability service—warranted a full write-down of the rate base at the time of the emergence from bankruptcy.[52] Talen's emergence from bankruptcy entailed in part the reduction in debt by creditors participating in the re-organization—in some cases purchased by those creditors at discount from the face value of the debt—in exchange for equity in the post-bankruptcy Talen. The Talen Filings' implicit failure to recognize any effect arising from the bankruptcy blocks inquiry of a material development relevant to determining the actual investment (or "acquisition cost" within the meaning of the Commission's original cost test) of the Power Plants' current owners (particularly those that acquired equity due to Talen debt previously acquired at a discount).

III. The Commission should reject Talen's proposed adder for "opportunity costs" for site redevelopment.

Talen also seeks an "adder" under both the Brandon Shores and Wagner CORS to compensate it for the development potential of the Power Plants' site. This "adder" should be rejected.

[52] The bankruptcy of the IR4 owner was much earlier in time compared to the commencement date of its RMR service term than that for the Power Plants following Talen's 2022 bankruptcy. The Commission has also not decided the issue in the proceeding, currently subject to a pending, contested "blackbox" settlement filing. However, absent further information from Talen, there is no principled basis to distinguish the different approach taken by the applicant in ER22-1539.

Talen's proposed "adder" aims to recover the alleged opportunity costs for delaying redevelopment of the Power Plants' site during the term of the CORS. The adder is based on estimated gains from the ultimate sale of the site after the term of the RMR at a purchase price assuming the highest and best alternative use of the site, less decommissioning and clean-up costs. The Talen witness asserts that the Talen Filings back-out the recorded book value of the site from the Power Plants' "rate base" in order to avoid double-counting.[53] Talen allocates the recovery of the "adder" between the Power Plants separate CORS, based on the Power Plants' relative nameplate capacities and proposes to shift the recovery of the full "adder" between the Power Plants, in the event one of the Power Plants and not the other completes its CORS term earlier than the other. The following table depicts the impact of the requested adder on the annual revenue requirements for the Brandon Shores and Wagner Power Plants.

Table 4			
Site Development Opportunity Cost Adder (assuming both power plants continue in operation)			
	Brandon Shores	Wagner	Total
Estimated Site Net Sale Value	$69,700,992	$38,436,840	$108,137,832
Annual Revenue Requirement Addition	$5,688,040.	$3,136,688	$8,824,728
Source: Exh. No. BSH-001, pp. 20-21 of 36; Exh. WAG-001, p. 18 of 32			

[53] Witness Schatzki reports the book value of the land, removed as described in the text, for the Brandon Shores, as approximately $19 million, and for Wagner, $10.8 million, respectively. Exhibit BSH-001, at 21; Exhibit WAG-001 (Schatzki Wagner Direct) at17-18 of 32. Talen does not provide the documentary bases for these amounts, nor the basis for the allocation of the land book cost among the Power Plants.

This item of proposed compensation is entirely without foundation and should be rejected by the Commission. *First*, Talen's proposal is contrary to the USofA because it is divorced from the original recorded "cost" of acquiring the land.[54] As such, this proposal is extraordinary, unprecedented, and not tethered to any limiting principle. While generally purporting to align its requested revenue requirements under the CORS with the Commission's USofA, Talen's request for a land development adder would support revaluing any land interest of any regulated utility devoted to public use and charging regulated rates—from its original cost when acquired and first devoted to public use—to a speculative value based on a potential sale in the future when removed from public use. The USofA's framework precludes this. Talen's proposal seeks adoption of a principle that would effectively unravel the USofA's accounting system.

Second, Dr. Schatzki claims to have developed a "traditional cost of service analysis for Units 3 and 4."[55] However, Dr. Schatzki attempts to include market-based land value for the "foregone potential use of the land"[56] due to the RMR. This is not an actual incurred cost of the Power Plants and the cost-of-service analyses do not include market-based values, but rather book values when computing revenue requirements. This

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[54] *See e.g.*, 18 C.F.R. Pt. 101, USofA, Acct. 310, Land and land rights (for Steam Power Generation). "This account shall include the *cost of land and land rights* used in connection with steam-power generation (see electric plant instruction 7); *id.*, Electric Plant Instructions 1.C. "The detailed electric plant accounts (301 to 399, inclusive) shall be stated on the basis of cost to the utility of plant constructed by it, and the original cost, estimated if not known, of plant acquired as an operating unit or system . . . . 7. Land and Land Rights. A. "The accounts for land and land rights shall include the *cost of land* owned in fee by the utility…") (emphasis added).

[55] Wagner CORS Transmittal Letter at 10; and Brandon Shores CORS Transmittal Letter at 1.

[56] Wagner CORS Transmittal Letter at 13–14; Brandon Shores CORS Transmittal Letter at 16–18.

proposal is inappropriate and should not be allowed in a cost-of-service-based rate. Talen is receiving a return and taxes on the land value and, therefore, is already receiving compensation for the use of the land. Furthermore, decommission22-15ng of this land would have occurred past the original deactivation date of June 1, 2025, and Talen would not have been able to sell this land for years. Talen does not explain or provide a rationale for why it should be paid the adder when it is operating the Power Plants during the term of the CORS, precluding decommissioning and development, and while it is receiving compensation for such operation. There is no real "opportunity cost" incurred in such circumstances. Instead, Talen's "adder" is a confected doubling up of compensation, presuming the fictional ability to deploy the asset for two conflicting purposes simultaneously.

Third, Talen analogizes its proposed land value "adder" to the recognition of "opportunity costs" arising from air emissions or other permit operational limits applicable to power plants that bid into wholesale competitive energy markets. This analogy is infirm. Generator resource operational permit limits affect the marginal going forward cost of power plants competing in a competitive power market. These permit limitations are potentially relevant to the formation of efficient price signals for those markets. On the other hand, land costs or values—particularly for land dispositions made long in the past or many years in the future—are "sunk" investments irrelevant to operational costs and efficient market signals based on marginal cost calculations.

Fourth, even if such opportunity costs were appropriate (which they are not), Talen's decommissioning and cleanup costs are entirely speculative. In fact, there may be no gains after a sale of the property after decommissioning and clean-up costs.

IV. The Commission should reject Talen's proposed CORS performance obligations as deficient.[57]

The reason for PJM's seeking PJM Reliability Service from the Power Plants and the payment of compensation to their owner is to address grid reliability violations that are anticipated to occur if the Power Plants were not operating. To achieve this motivating purpose, there needs to be some level of assurance that the entity supplying the PJM Reliability Service will perform. However, Talen's proposed CORS requires continuing payments without sufficient assurances of performance.

Customers' obligation to pay the monthly fixed costs and reimbursement of PIs to Talen under the CORS is absolute.[58] PJM's right to terminate the CORS seemingly only arises following six months' prior notice by PJM[59] or if the Power Plant(s) become "inoperable" or PJM fails to approve a PI rendering the unit(s) "unable to continue operating without such [PI]."[60] By contrast, Talen's obligations to operate the Power

[57] References are to common sections of the separate Plant specific CORS applicable to each of the Brandon Shores and Wagner Power Plants, respectively. For the proposed RMR Continuing Operations Rate Schedules, *see* Brandon Shores Filing, Attachment A; Wagner Filing, Attachment A.

[58] CORS, Secs 5.1 and 5.2.

[59] CORS, Sec. 2.4.

[60] CORS, Sec. 2.5(b).

Plants have little, if any, binding effect. Thus, Talen is relieved of the general performance obligations for generators participating in the PJM markets, including generators providing PJM Reliability Service.[61] Moreover, Talen expressly disclaims any guarantee of performance.[62] Operating parameters for the Power Plants, albeit initially specified, can be altered by Talen unilaterally if and to the extent "a Unit experiences a physical operational limitation that prevents it from meeting the [operating] parameters."[63] Moreover, Talen is relieved from performance if there is an "Outage" of the units.[64]

PJM's only remedy for Talen's non-performance seemingly is termination of the RMR arrangement. But the Section 3.4 of the proposed CORS provides that in the event of termination Brandon Shores or Wagner "shall be entitled to recover all such

[61] CORS, Sec. 3.1 ("…operation of the Units consistent with the terms and conditions of this Rate Schedule shall not be deemed inconsistent with the performance obligations identified in section 121 of the PJM Tariff); *see* OATT, Sec. 121 (generally applicable to Units providing PJM Reliability Service: "Performance Standards: A generating unit proposed for Deactivation that continues to operate for reliability beyond its desired Deactivation Date pursuant to Part V of the Tariff *shall continue to be operated according to existing standards applicable to generating units located in the PJM Region."* (emphasis added)). Among the standards applicable to such generating units is Good Utility Practice (OATT, Defined Term). *See, e.g.*, OATT Appendix 2, Standard Terms and Conditions for Interconnections, Secs. 4.1, 5.1.

[62] CORS, Sec. 3.3(b) (Talen "does not guarantee that such Unit(s) will start or operate at rate capacity, and [Talen] does not guarantee the availability of the Unit(s) in response to a PJM scheduling or dispatch notice").

[63] CORS, Sec. 3.4.

[64] CORS, sec. 3.3(d). The CORS further defines "'Outage' …[to] mean a Forecasted, Planned, Maintenance Outage, Unplanned Forced Outage, or a Partial Outage/Derate as such terms are defined in the PJM Governing Documents." CORS, Sec. 1.9. The PJM Governing Documents distinguish among Generator Forced, Generator Maintenance and Generator Planned Outages, as separate distinctive defined terms. OATT, Definitions.

unrecovered costs[.]"[65] This provision is abusive to ratepayers to the extent it enables Talen to recover its entire prospective fixed revenue requirement over the full term of the RMR in the event of early termination by PJM.

In sum, Talen's performance obligations are similar to those for supplying non-firm energy. Talen's obligations are wholly at variance with the almost "take or pay" nature of the counter-party obligation for payment of Talen's revenue requirements and are subject only to limitation by the 6-month advance termination notice whose efficacy is undercut by the grid reliability violations ensuing from Talen's exit from the PJM Reliability Service arrangement and the potentially abusive recovery due to Talen in the event of early termination. In this context, supplier compensation and supplier performance risk/obligation are seriously misaligned. At a minimum, undue discrimination exists between Talen's level of requested revenue requirements and associated performance risks with those faced by generators participating in the PJM capacity market and subject to the performance requirements of that market.

V. The proposed capital structure, overall rate of return, and return on equity are unreasonable and unjustified.

Talen proposes to establish its rate of return on equity ("ROE") for purposes of setting the revenue requirements for the CORS for the Power Plants based on estimates made by Dr. Schatzki utilizing the Capital Asset Pricing Model ("CAPM"). Dr. Schatzki's

[65] CORS Section 5.2 arguably is, to the same effect, lacking a clear cut-off to the obligation to pay the CORS during the entire term.

estimates are anchored by a proxy or "peer" group of companies he utilizes "whose business almost exclusively involves independent power production."[66]

As a general matter, Dr. Schatzki's analysis wholly fails to recognize that operation of the Power Plants for reliability service and payment of revenue requirements is equivalent to that of a regulated transmission asset with materially less risk than that faced by the merchant generators used in Dr. Schatzki's analysis. Recognition of this lower level of risk translates into lower ROEs than those afforded to merchant generators operating generally in competitive wholesale power markets. Such an explicit downward adjustment was explicitly required by the Commission in the *Constellation Mystic Station* proceedings.[67] While not addressed by the Commission and the subject of a "black-box" contested settlement currently pending before FERC (ER22-1539 and ER23-2688), in the most recent prior filing within the PJM footprint for reliability service, the applicant in its initial filing in the proceeding adopted this approach in its request for ROE, using the ROE of the interconnecting transmission owner to set its proposed revenue requirements for PJM Reliability Service.[68] Accordingly, Talen's requested ROE is fatally deficient and

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[66] Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 23. *See* Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 27 (describing the proxy group, for use in estimating the CAPM method employed for establishing the requested return on equity as follows: "Q. Did you rely on a proxy group to estimate the CAPM? A. Yes. I selected a group of companies that each have a large fraction of their business in independent power production. These companies are the most comparable in terms of market risk to Talen, whose business almost exclusively involves independent power production. These companies are AES Corporation ("AES"), Constellation, NRG Energy, Inc. ("NRG"), and Vistra Corp. ("Vistra")").

[67] *Constellation Mystic Power II*, 172 FERC at P 132.

[68] Docket No. ER22-1539, NRG Power Marketing LLC Transmittal Letter at 12 (April 1, 2022); Exhibit. No. NPM-001, Lovinger Testimony at 28.

overstated due to its failure to recognize the risk mitigants inherent in the provision of PJM Reliability Service.

In addition to failing to properly account for reduced-risk of operating as an RMR resource, Dr. Schatzki's capital structure, proxy/peer group and overall ROR are unjust and unreasonable and are not suitable for setting the Brandon Shores and Wagner CORS Monthly Fixed-Cost Charge.

Dr. Schatzki calculates the Brandon Shores and Wagner CORS RMR revenue requirement with a 11.26% overall rate of return (ROR), reflecting his proposed weighted average of the cost of debt and cost of equity (ROE).[69]

Because Brandon Shores and Wagner do not issue their own debt, Dr. Schatzki uses the capital structure of the units' ultimate parent, Talen Energy of 41% debt and 59% equity.[70] For the cost of debt, Dr. Schatzki uses the coupon rate of Talen's long-term debt collected by issuing senior secured notes, a value of 8.625%.[71] For the ROE component, Dr. Schatzki use the Capital Asset Pricing Model (CAPM) applied to a four-member proxy group, using the median estimate of three variations in the CAPM's assumptions.[72]

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[69] Exhibit BSH-003, Schedule 2, line 9; Exhibit WAG-003, Schedule 2, line 9.

[70] Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 22:10-17; Exhibit WAG-001 (Schatzki Wagner Direct) at 1:21-27.

[71]Exhibit WAG-001 (Schatzki Wagner Direct) at 19:13-17; Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 23:2-6.

[72] Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 23–31 Exhibit WAG-001 (Schatzki Wagner Direct) at 20–28.

The range of Dr. Schatzki's ROE analysis is 12.66% to 13.54%, with a median ROE of 13.11%.[73] Along with his capital structure and cost of debt, the resultant ROR of 11.26%, as show in Table 5, is used to set the Brandon Shores and Wagner Monthly Fixed-Cost Charge of $14,619,407 and $3,361,926, respectively (as set forth in Section 5.1 of each units' CORS).

Table 5: Dr. Schatzki's Proposed CORS Capital Structure & Return

	Ratio	Cost	Wtd. Cost
Debt	41%	8.63%	3.56%
Equity	59%	13.11%	7.70%
Return (ROR):			**11.26%**

Setting aside the question of whether Talen Energy should be entitled to recover in its CORS Monthly Fixed-Cost Charge a *return on* (i.e., ROR) and *return of* (i.e., depreciation) net plant, Dr. Schatzki's Capital Structure, proxy/peer group, ROE and overall ROR are unjust and unreasonable, inconsistent with Commission precedent and are not suitable for setting the Brandon Shores and Wagner CORS Monthly Fixed-Cost Charge.

Sole Reliance on the CAPM: As noted above, Dr. Schatzki relies on several different applications of the CAPM in support of his recommended 13.11% ROE. He relies on three CAPM approaches and uses two estimates for the market return with respect to each approach to determine six different CAPM based ROE results. Dr.

[73] Exhibit WAG-001 (Schatzki Wagner Direct) at 28:9-12; Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 31:24-27.

Schatzki's recommendation is based on the median of these six results.[74] While the Commission's ROE policy is presently unsettled following the United States Court of Appeals for the District of Columbia Circuit remand of the Commission's Opinion No. 569 series of decisions,[75] it is evident that Dr. Schatzki's analysis significantly departs from Commission precedent and norms. Dr. Schatzki's sole reliance on the CAPM method stands in stark contrast to the Opinion No. 569 series of decisions' reliance on multiple analytical methods and the fact that the Commission has relied on a form of the discounted cash flow method for several decades, beginning in the early 1980s, for determining the ROE.[76] As such, the Talen Filings do not comply with FERC precedent. An evidentiary hearing is required to determine the appropriate ROE methodology, inclusive of the issues identified below, for use in Wagner's and Brandon Shores' RMR Rate Schedule.

Non-Conforming CAPM Analysis: There are several differences between the CAPM models utilized by Dr. Schatzki and the CAPM approach adopted by the Commission in the Opinion No. 569 series of decisions and therefore further investigation by the Commission is warranted. Two of the three approaches rely on betas

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[74] *See* Exhibit WAG-001 (Schatzki Wagner Direct), at 28:8-12; Exhibit No. WAG-003, at 6, Schedule 6.

[75] *See MISO Transmission Owners, et al. v. FERC*, 45 F.4th 248 (D.C. Cir. 2022).

[76] *See, e.g.*, *Generic Determination of Rate of Return on Common Equity for Pub. Utils.*, FERC Stats. & Regs. ¶ 30,644, at 31,338 (1985) ("Order No. 420") ("[T]he Commission places primary reliance on the discounted cash flow (DCF) approach to estimating the market required rate of return on common equity."); *see also* Opinion No. 396-C at 61,189 ("The Commission has historically used a constant growth DCF model.").

that go through a "deleveraging" process, which seeks to identify the underlying operational risk of each proxy group company and are then "releveraged" to match the requested Talen capital structure.[77] Additionally, one of these two approaches also includes the use of a beta related to debt to incorporate default risk as part of the ROE estimate. The Commission has not previously relied on betas produced in this manner. Rather, the Commissions has relied on the "leveraged" betas produced by Value Line and Bloomberg.[78]

Other differences to the Commission's CAPM approach include the measurement of 30-year Treasury bond for the single month of February 2024 as opposed to a six-month study period.[79] Additionally, the Commission applied a size premium adjustment to the ROE estimate for each proxy group member based on their respective market capitalization, whereas, Dr. Schatzki analysis applies a size premium adjustment based on the market capitalization of Talen.[80] This leads to an increased ROE given that Talen's market capitalization is considerably lower than that of the members in his proxy group.

Additionally, Dr. Schatzki's CAPM approaches produce results pursuant to two different market return estimates, that use either (a) Value Line projected earnings growth rates (with a market return of 12.09%) or (b) IBES projected earnings growth rates (with

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[77] Exhibit WAG-001 (Schatzki Wagner Direct) at 20:2-13.

[78] *DATC Path 15, LLC,* 177 FERC ¶ 61,115 at P 111.

[79] Opinion No. 569, 169 FERC ¶ 61,129 at P 238.

[80] See e.g., Opinion No. 575, 175 FERC ¶ 61,136 at Appendix III: CAPM Results.

a market return of 11.59%).[81] In support of using Value Line growth rates, Dr. Schatzki points to P 78 of Opinion No. 569-A where the Commission explains it will consider the use of Value Line sourced growth rate but overlooks addressing the Commission's later statement at P 83 which clarifies that the Commission will evaluate proposals to use of Value Line short-term projected earnings growth rates based on the evidence produced in future proceedings.[82] Dr. Schatzki has not provided evidence to support the use of Value Line growth rates. It is also noteworthy that in a subsequent proceeding to Opinion No. 569-A the Commission evaluated such a proposal but declined to adopt the use of Value Line growth rates.[83]

CAPM Equity Risk Premium (ERP). Joint Protestors object to Dr. Schatzki's ERP of 7.21% and 7.71%, developed under two methods. This ERP is substantially higher than the current Kroll 5.5% ERP for the U.S. Market.[84]

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[81] Exhibit WAG-001 (Schatzki Wagner Direct) at 22:2-17.

[82] 171 FERC ¶ 61,154 (2020).

[83] *See Pac. Gas and Elec. Co*., 178 FERC ¶ 61,175, at P 197 (2022) ("As discussed above, the Commission stated in Opinion No. 569-A that it would consider the use of Value Line growth rates in the expected market return calculation. In that proceeding, the record did not contain sufficient evidence to use Value Line growth rates, and accordingly, the Commission adopted an expected market return based on IBES growth rates. Here, we are not persuaded by PG&E's assertions that the facts and circumstances of this proceeding favor use of Value Line growth rates. In this circumstance, we find that it is more appropriate to adopt an expected market return based on IBES growth rates because using IBES growth rates promotes consistency between the DCF and CAPM models. The record does not demonstrate that the costs of sacrificing this consistency would be outweighed by the diversity of data sources and other benefits of Value Line growth rates. Furthermore, using IBES growth rates has the advantage of representing input from multiple analysts, unlike that of a single analyst for Value Line. This finding is consistent with the Commission's use of IBES growth rates for the CAPM subsequent to Opinion No. 569-A.") (internal citations omitted).

[84] *See Kroll Recommended U.S. Equity Risk Premium (ERP) and Corresponding Risk-free Rates (R f), Current Guidance January 2008–Present* (June 8, 2023) https://www.kroll.com/-/media/cost-of-capital/kroll-us-erp-rf-table-2023.pdf" (showing equity risk premium of 5.5% and risk-free rate of 3.5%).

Proxy Group. Dr. Schatzki proposed "peer group" consisting of AES Corporation, Constellation Energy, NRG Energy Inc., and Vistra Corp. Dr. Schatzki explains that he "…considered the nature of the business in which his peer group companies operate, their geography, the availability of their financial information, and whether publicly available data was sufficient to reliably measure each type of financial parameter."[85]

Dr. Schatzki states that while the Commission policy is to use "…a national group of companies considered electric utilities by Value Line… most of these companies are not truly comparable to the Talen's business, which is focused on unregulated independent power generation."[86]

The Joint Protestors urge the Commission to reject Dr. Schatzki's proposed proxy group. The Joint Protestors preliminary review has identified two primary issues with the proposed proxy group. *First*, Commission policy holds that "a proxy group should consist of at least four, and preferably at least five members, if representative members can be found."[87] The Joint Protestors note that Dr. Schatzki's Peer Group includes Vistra Corp., which was involved in acquisition of a PJM merchant generating entity, Energy Harbor, Corp., from March 6, 2023 to March 1, 2024.[88] The Commission's Proxy Group Policy, however, is to exclude companies with ongoing merger and acquisition activity. While it

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[85] Schatzki Brandon Shores Testimony, Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 27.

[86] *Id.*

[87] *SFPP, L.P.*, 134 FERC ¶ 61,121 at P 203 (2011).

[88] Docket No. EC23-74, Joint Application for Authorization Under Section 203 of the Federal Power Act of Energy Harbor Corp. (April 17, 2023).

is not entirely clear the period used by Dr. Schatzki measure his CAPM inputs, the Joint Protestors note that if Vistra Corp. is excluded from the proxy/peer group, the size of group will fall to three (3) members, in apparent violation of Commission policy.

Second, Dr. Schatzki's reliance on a proxy group of companies with significant independent/merchant power production[89] operations, rather than the Value Line electric utilities, is inappropriate for determining an ROE that will be used as part of the cost-based RMR rate. A merchant power producer is exposed to the market risk of not recovering its costs. Such risks are dissimilar to risks inherent in a cost-based rate structure which significantly reduces the risks involved in the Company's operations. Moreover, it bears noting that in the order setting the ROE in the *Constellation Mystic Power* proceeding,, the Commission did not accept arguments that the generator had risks similar to that of a merchant generator[90] and the Commission relied upon its traditional use of Value Line electric utilities to determine the proxy group.[91]

Capital Structure and Overall Return. The Commission's policy is to use the capital structure of the rate applicant if the applicant issues its own non-guaranteed debt,

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[89] Exhibit WAG-001 (Schatzki Wagner Direct) at 20:4-6, 23:23 – 24:6.

[90] *See Mystic Power, LLC* 176 FERC ¶ 61,019, at P 26. ("Mystic 8 and 9 will be operating under a cost-of-service agreement that allows Mystic to recoup almost all of its prudently incurred costs during the period. Therefore, Mystic does not face a comparable risk profile to that of a merchant generator, whose revenues are comparatively much more variable and unpredictable.").

[91] *Id.* at PP 139-167.

has a bond rating, and has an equity ratio within the historical range approved by the Commission.[92]

Under this precedent, Brandon Shores and Wagner fail these tests—the units have no bond rating and do not issue debt. Thus, as the Commission held in *Constellation Mystic Power* (Mystic Power), when an applicant's capital structure cannot be used, the Commission's policy has been to look at the capital structure of the organization that does the financing for the regulated entity, provided the result is a just and reasonable rate.[93]

But use of Talen Energy's capital structure—as Dr. Schatzki has done for Brandon Shores and Wagner—is not automatic. Indeed, the Commission held that such a scenario "does not require the use of the immediate parent's capital structure for ratemaking purposes. In reviewing a proposed capital structure, the Commission seeks to achieve a balance between its obligation to protect consumers with its obligation to ensure that a regulated entity has a reasonable opportunity to attract capital and earn a fair return on its investment."[94]

Moreover, the Commission does not hold to an "absolute policy requiring that, if the [applicant's] equity ratio falls within the range of equity ratios of the proxy

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[92] Opinion No. 414, 80 FERC at 61,667; Opinion No. 414-A, 84 FERC at 61,415.

[93] *Constellation Mystic Power*, *LLC*, 165 FERC ¶ 61,267, at P 49 (2018) (citing Opinion No. 414-A, 84 FERC at 61,415; *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260, at PP 173, 184-185).

[94] *Constellation Mystic Power*, 165 FERC at P. 49.

companies utilized for the DCF analysis, the [applicant's proposed] equity ratio automatically will be used."[95]

Here, the Joint Protestors submit that Brandon Shores and Wagner have not demonstrated that Talen Energy's capital structure will result in just and reasonable rates. Based on a preliminary review, the Joint Protesters find the capital structure and cost of debt adopted by the company problematic for two primary reasons. First, the equity balance used in the capital structure is based on the market value of Talen's publicly listed stock rather than the book value of the equity capital. The Commission has long relied on book values when determining the capital structure for the rate of return.[96] The use of the market value of equity greatly inflates the equity portion of Talen's capital structure. For instance, if Talen's equity book value were used, the equity ratio would fall from the requested 59% to approximately 47%.[97] Second, the use of Talen as a proxy for the capital structure and cost of debt is inappropriate because Talen is reported by Dr.

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[95] *Id.* at P 50.

[96] *See*, *e.g.*, 123 FERC ¶ 61,098 at P 73 ("…The Commission has a strong preference for using the actual capital structure of the company in developing its rate of return, unless there is an overriding reason not to do so. Further, using FERC Form No. 1 data is consistent with Commission precedent for PJM transmission owners with formula rates." (cites omitted)). Additionally, the formula for the allowance for funds used during construction set out in the Uniform System of Accounts regulations require that the book value of common equity to be used to determine the capital structure. See 18 C.F.R. Part 101, USofA, Electric Plant Instruction 3(17).

[97] Talen's 2023 Annual Report reports a total stockholder equity balance of $2,4457 million which includes a negative $23 million of accumulated other comprehensive income (loss), which, if removed, increases the total equity to $2,503 million. Using this adjusted total equity and the debt balance of $2,849 million (reported Exhibit No. WAG-003 at 5, Schedule 5) results in a total capitalization of $5,352 million. The total equity of $2,503 million is approximately 47% of the total capitalization amount.

Schatzki as having a below investment grade long-term credit rating of B+.[98] As a result of Talen's below investment grade credit rating, it is inapposite to assume that Talen's capital structure and cost of debt is representative of the inherent risk and cost basis for Wagner under the regulated cost-of-service agreement which will allow Wagner to recover prudently incurred costs during the term of the agreement. Moreover, the Commission has previously found that a parent company's below investment grade credit rating, was sufficient, in part, to support the finding that the parent's capital structure was anomalous and not representative of the subject utility's risk profile.[99] As a result of the unsuitability of using Talen as a proxy, an evidentiary hearing is required to determine an appropriate hypothetical capital structure and cost of debt for use in Wagner's RMR Rate Schedule.

Thus, to address the concerns raised herein, and following Commission precedent, one approach that could be taken is to set the Brandon Shores and Wagner CORS monthly fixed-cost charge using the interconnected utility's cost structure and rate of return. The relevant interconnected utility for Brandon Shores and Wagner is Baltimore Gas & Electric (BGE). Specifically, the CORS Monthly Fixed-Cost Charge could be set

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[98] Exhibit WAG-001 (Schatzki Wagner Direct) at 23:29 – 24:1 ("…Talen has a rating of B+, which is below investment grade…").

[99] *High Island Offshore System, L.L.C*, 110 FERC ¶ 61,043 (2005) at PP 145-146 ("…we find that GulfTerra's capital structure may be found to be anomalous on the ground that it is not representative of the pipeline's risk profile… Staff, however, provided evidence that GulfTerra's bond rating is below investment grade. The Commission finds that this evidence, combined with GulfTerra's assertions, is sufficient to support the ALJ's finding that GulfTerra's capital structure is not representative of HIOS' risk profile.") (citations omitted).

using the BGE base ROE of 10% and capital structure in BGE's FERC-approved PJM Transmission cost-of-service revenue requirement.

The BGE ROE and capital structure is an appropriate option for setting the Brandon Shores and Wagner CORS monthly fixed-cost charge. As the Commission has noted:

> "[I]t has been the Commission's general policy to allow an independent power producer to use the authorized rate of return and return on common equity of an interconnected utility for reactive power compensation, because . . . an interconnected utility's return is a conservative estimate of a merchant generator's return because the merchant generator faces more risk."[100]

Based on the foregoing, it is appropriate to consider the use of BGE's ROR to set the Brandon Shores and Wagner CORS monthly fixed-cost charge. The BGE accepted base ROE is 10%, exclusive of a 50-basis-point adder for RTO participation.[101] The BGE capital structure is 46% debt and 54% equity, and the BGE debt cost rate is 3.95%.[102] Please see Table 6 for a build-up of the BGE ROR, which results in a 7.22% ROR. An evidentiary hearing, and a discovery process, is required to determine the appropriate ROR.

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[100] *Bluegrass Generation Co., L.L.C.,* 118 FERC ¶ 61,214, at P 86 (2007).; also see *Duke Energy Fayette, L.L.C.,* 104 FERC ¶ 61,090 (2003) (allowing Duke Energy Fayette to use a proxy based on the capital structure and rate of return of Allegheny Power); *Calpine Fox LLC*, 113 FERC ¶ 61,047 (2005) (allowing Calpine Fox to use the capital structure and rate of return of American Transmission Co., LLC in calculating its annual revenue requirement for reactive service).

[101] BGE FERC PJM Transmission Formula Rate at Attachment H-2A (Tab 1) at lines 116-121: https://www.pjm.com/-/media/markets-ops/trans-service/june-to-may/2024-2025/bge/attachment-h-2a-ptrr.ashx.

[102] *Id.*

Table 6: Joint Protestors Proposed CORS Capital Structure & Return

	Ratio	Cost	Wtd. Cost
Debt	46%	3.95%	1.82%
Equity	54%	10.00%	5.40%
Return (ROR):			**7.22%**

Joint Protestors note that in the Indian River 4 RMR proceeding, NRG Business Marketing LLC utilized the ROE of the interconnecting utility Delmarva Power and Light Company to set the ROE in the Indian River unit 4 cost of service.[103] In its application, NRG PLM utilized a 7.46% overall ROR in the cost of service for Indian River RMR's monthly fixed charge rate,[104] similar to the 7.22% set out above in Table 6 above.

VI. The Talen Filings fail to meet the Commission's ratemaking cost support requirements for electric cost of service rate schedules, and Talen should be denied requests for waivers to support its cost of service.

Talen is obligated under section 205 of the FPA to show that the costs it seeks to recover are just and reasonable. While Talen ostensibly includes a nominally conforming "traditional" cost of service analysis/study in its filings,[105] the study universally fails to include support for the source and validity of the cost data inputs, the ratemaking methodologies, and principles used to develop the cost-of-service study inputs.

Furthermore, Talen seeks waivers from its obligation to provide the cost support and data needed for a cost-of-service RMR rate. Talen states:

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[103] Docket No. ER22-1539, NRG PML Transmittal Letter, at 10 (April 1, 2022).

[104] *See* NRG PML witness Alan R. Lovinger, Exhibit No. NPM-001, Statement 2: Rate Base, Return and Income Tax Allowance, line 9, return of 7.46%.

[105] See Exhibit WAG-003 and BSH-003.

> Wagner's [and Brandon Shore's] cost data consists of those items required to support its monthly revenue requirement pursuant to the CORS for the CORS Term. Therefore, Wagner respectfully requests waiver of those provisions of Section 35.13 of the Commission's regulations that are not necessary for this filing, including, but not limited to, the Commission's regulations at 18 C.F.R. § 35.13(d), to the extent applicable. Further, Wagner [and Brandon Shores] respectfully request[s] that the Commission grant waiver of any of the Part 35 requirements that are not applicable to this filing and grant any other necessary waivers to permit the CORS to become effective as requested.[106]

Talen is incorrect that these regulations are not necessary for Commission action on this filing. Under a cost-based rate, Talen has an obligation to provide its COS analysis in a workable excel format and provide the supporting data, calculations and documentation for the inputs included in its filing. Talen should be denied a waiver that obviates its obligation to support its cost-of-service RMR rate.

VII. The Commission should deny other items reflected in Talen's proposed cost of service.

A. Talen's proposed Project Investment ("PI") recovery is flawed.

According to Talen's proposal, each month during the term of the RMR Rate Schedule, PJM is required to pay Talen a monthly payment to reimburse the costs of project investment or "PI." The Talen Filings define PI as investments made to enable the Power Plants operating under an RMR "to continue operating for the period of time during which PJM has identified a reliability need for the Units. A project investment may include repairs, replacements, actions required for North American Electric Reliability Corporation or other regulatory compliance, and maintenance of unit facilities

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[106] Wagner CORS Transmittal Letter at 18; Brandon Shores CORS Transmittal Letter at 21.

and equipment and associated parts, supplies, labor (including overtime if consistent with Good Utility Practice), and overheads."[107] Such investments must be made after September 30, 2023 for Brandon Shores and after December 31, 2023 for Wagner. Pursuant to the RMR Rate Schedule[108], the monthly project investment tracker would be calculated as:

$$\mathit{Monthly\ Project\ Investment\ Tracker\ Payment} = \frac{r/_{12}}{1-\left(1+r/_{12}\right)^{-n}} \times (\mathit{PI\ Incurred\ during\ month})$$

In the proposed tracker, "r" is the carrying charge rate per annum and "n" is the number of months remaining in the Term. Monthly project investment payments for project investments incurred in any specific month shall remain fixed for the number of months remaining in the Term.[109] The RMR Rate Schedule provides that carrying charges will be accrued on Actual PI costs at a rate of 13 % per annum from when the cost is incurred, amortized each month over the remaining RMR term.[110]

The carrying charge rate used, thresholds requested and process for reviewing unrecovered project investment costs are unjust and unreasonable. The cost recovery procedures established for the monthly project investment tracker enable Talen to recover

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[107] Brandon Shores Filing, Attachment A, RMR Rate Schedule, Section 1.15; Wagner Filing Attachment A, RMR Rate Schedule Section 1.15. Collectively, this filing refers to the proposed rate schedules as "CORS."

[108] *Id.*

[109] CORS, Section 5.2.

[110] *Id.*

costs subject to the tracker, to which is applied a carrying charge. It appears from the provision in Section 5.2.E[111] that only PJM can participate in such review. It is unjust and unreasonable to not allow all customers paying the rate to be able to review and challenge procedures to ensure that all interested parties retain their rights. It has been longstanding Commission policy that all interested parties have rights under protocols to review filings that are "formula rate" in nature.[112] Furthermore, Talen attempts to implement a project investment threshold of $500,000 to trigger notice to PJM of such project.[113] To the extent that a project that exceeds $100,000 but not $500,000, Talen shall also notify PJM.[114] These thresholds are higher than NRG's filing with respect to IR4 which sought a $350,000 and $50,000 threshold, respectively. Given the current estimates of the project investments identified, it appears that these project thresholds are too high because some of the already identified projects would not be triggered under these thresholds (e.g. Replacement of Unit 3 Boiler Tube Dissimilar Metal Welds, approx. $175,000).[115] Talen

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[111] Wagner Attachment A and Brandon Attachment A.

[112] *E.g.,* protocols for review in FERC dockets EL22-37 Idaho Power Company; EL22-38 PacifiCorp, EL22-39 Public Service Company of Colorado; and EL22-41 Puget Sound Energy, Inc (show cause orders deeming existing formula rate disclosure protocols deficient based on insufficiently broad scopes of participation by interested parties).

[113] *Id*., Section 5.2.E.

[114] *Id*.

[115] Wagner CORS Transmittal Letter at 15; Brandon Shores Transmittal Letter at 18.

should be required to lower these thresholds to a more reasonable amount to ensure the projects are properly noticed and customers are afforded a right to review them.

Talen fails to justify and support its proposal to use a 13% carrying charge rate to accrue carrying charges on unrecovered project investment costs. Talen's carrying charge proposal results in an overstatement of carrying charges, which is even substantially higher than the overstated rate of return requested in its filing.[116] Talen should be utilizing a short-term interest rate in this calculation for short-term borrowings available to Talen.

Talen has failed to provide examples showing the application of the carrying charge and the monthly project investment cost tracker. Without this information, the Joint Protestors are unable to verify whether Talen's proposed mechanism is just and reasonable. For projects that would accrue carrying costs, Talen should explain how the amount incurred monthly is derived and whether carrying charges are included in construction amounts. Furthermore, Talen's mechanism only addresses cost recovery without taking into account construction periods and when such plant additions will be "used and useful" providing RMR service. The lack of examples and recognition of construction periods deems Talen's filing deficient.

B. Talen has failed to discuss the tax treatment of project investment costs and the effect on ADIT.

Talen fails to discuss the tax treatment of the project investment cost, whether there will be timing differences between when costs are booked and recovered in the

[116] *See supra* Section IV (discussing Talen's proposed rate of return for Brandon Shores and Wagner).

RMR rate, or when they will be reflected on the income tax returns. Without this discussion, the Joint Protestors are unable to determine whether there are any ADIT balances applicable to project investment costs and how should they be factored into the monthly project investment tracker rate.

C. Talen is attempting to recover costs related to the project investment prior to June 1, 2025 and potentially is double recovering investment in the projected period of the plant balances for the monthly fixed charge rate.

In relation to project investment as of January 1, 2024 (See RMR Tariff 5.2.B), Talen discusses with respect to the Wagner Power Plant that it anticipates project investment costs for various projects identified in subparts i through ix. However, it is unclear what projects Talen anticipates incurring prior to the June 1, 2025, effective date and whether these projects were already included in the projected balance utilized to compute the monthly fixed charge rate which was based off of plant values as of June 1, 2025.[117] Per the definition of the Wagner's PI investment, Talen is attempting to recover costs after December 31, 2023.[118] As Talen explains, "On October 16, 2023, Wagner notified PJM, pursuant to Section 113.1 of the PJM Tariff, that it intended to retire Wagner Units 1, 3, 4, and CT 1 effective June 1, 2025…."[119] Therefore, Talen would have incurred costs associated with repairs that appear to have most likely existed for many years prior to the request for an RMR. Some of the projects being proposed appear to be

[117] Exhibit WAG-003, Schedule 2, Line 1 and n.1.

[118] Wagner Filing, Attachment A, Section 1.15.

[119] Wagner CORS Transmittal Letter at 6.

normal repairs that would have occurred regardless of the RMR, and which were required to operate until June 1, 2025. Talen fails to disclose which projects are to be incurred prior to the June 1, 2025, effective date and disclose whether these projects were utilized in the plant balances for the monthly fixed charge rate. Nor does Talen provide documentation in the testimony supporting the need for these project investments.

Furthermore, Talen fails to discuss how these costs will be recovered prior to the effective date of the RMR, whether there will be any carrying charges, and what projects they relate to. Talen's attempt to recover costs incurred prior to June 1, 2025, is unsupported, as Talen has failed to explain why they were incurred and why recovery is appropriate during the term of the RMR arrangement. The lack of clarity regarding projects identified as of January 1, 2024, and any amounts prior to the effective date of June 1, 2025, should not be permitted in the absence of supporting documentation to address these concerns that they are not associated with normal maintenance and repairs that would have occurred regardless of the RMR and that they have not double recovered these projects through the monthly fixed charge rate and the project investment tracker.

With respect to Brandon Shores, Talen discusses that, as of January 1, 2024 (See RMR Tariff 5.2.B), it anticipates project investment costs for various projects identified in subparts i through v. However, it is unclear what projects Brandon Shores anticipates incurring prior to the June 1, 2025, effective date and whether these projects were already included in the projected balance utilized to compute the monthly fixed charge rate which was based off of plant values as of June 1, 2025.[120] Per the definition of the Brandon Shores' PI investment, Talen is attempting to recover costs after September 30, 2023.[121] Talen has not provided an explanation for the PI investment that incurred during the period of PI investment from September 30, 2023, and the projects identified as of January 1, 2024. Similar to Wagner, for Brandon Shores Talen has failed to explain why they were incurred and why recovery is appropriate during the term of the RMR arrangement and that they have not double recovered these projects through the monthly fixed charge rate and the project investment tracker.

The lack of clarity regarding projects identified as of January 1, 2024, and any amounts prior to the effective date of June 1, 2025, should not be allowed absent supporting documentation to address concerns that they are not associated with normal maintenance and repairs that would have occurred regardless of the RMR and that Talen is not double recovering plant investment.

D. Brandon Shores' use of a 2022 test year for expenses, prepayments and inventories is unsupported.

For Brandon Shores, Dr. Schatzki claims that he utilized 2022 data to compute prepayments and inventories because he "was advised that 2023 accounting information is not representative of future expenditures expected to be incurred for the CORS Term for a combination of factors, particularly changes in operations and maintenance

[120] Exhibit BSH-003, Schedule 2, line 1 and n.1.
[121] Brandon Shores Attachment A, Section 1.15.

associated with the decision reached in 2023 to retire the Brandon Shores facility."[122] He also utilizes 2022 as the starting point to compute O&M expenses[123] and A&G expenses.[124] However, Dr. Schatzki provides no further information as to the specific drivers, other than vague statements regarding retirement, as to why 2023 was not the appropriate test year to utilize. In addition, he does not state the amounts incurred during 2023, provide a comparison between 2022 and 2023, or make any attempt to potentially adjust 2023 data for these potential outliers. Furthermore, he does not explain why 2023 is not representative of O&M and A&G expenses, prepayments and inventories during the RMR period in light of the fact that the unit will only be running when called upon by PJM. Further discovery is needed to evaluate whether the 2022 test year is appropriate.

E. Talen's filing is unclear whether the list of anticipated project investment has been agreed to by PJM or whether these projects are necessary.

Talen's filing does not indicate whether the listing of anticipated project investment has been agreed to by PJM.[125] The Joint Protestors will need to assess the listed projects through discovery and decide whether they are appropriate investment for a generating unit under an RMR arrangement during its anticipated term (running to 2028 for Brandon Shores and potentially for Wagner to 2030). Also relevant in assessing the

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[122] Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 19:16-20.

[123] *Id.* at 32:22-23.

[124] *Id.* at 34:24-27.

[125] Wagner CORS Transmittal Letter at 15–17; Brandon Shores CORS Transmittal Letter at 18–19.

need for a method for cost recovery of the PIs is the fact that the Power Plants will be operating through June 1, 2025, (prior to the RMR arrangement's term commencing) in its current condition without some of these project investments. Some of the project examples of concern include:

- SCR Catalyst Bed Replacement: These beds typically have a 15–20-year life. It may be cheaper to purchase additional NOx offsets than to install new catalysts.
- Baghouse rebagging needs to be reviewed and may not be necessary.
- Ovation hardware & software upgrades are unnecessary for the short remaining life of the project.
- Generator & Turbine inspections should be scaled back or eliminated.

F. Talen has failed to support the cost reimbursement mechanism to recover variable operations and maintenance costs or provide a review process for the mechanism.

The Talen Filings include a mechanism to recover "variable" O&M expense during the pendency of the term of the RMR agreement.[126] Talen has failed to propose a tracker for fuel and variable operations and maintenance costs to ensure that all costs are identified and that there is no duplication for expenses that should have been considered recovered under the monthly fixed charge rate. There is no detailed expense account information that would allow the Joint Protestors or other interested parties to review the types of costs under the categories identified and included in this variable O&M reimbursement mechanism, no listing by USofA account of costs included in this

[126] Wagner Filing, Attachment A at Section 5.3; Brandon Shores Filing, Attachment A at Section 5.3.

mechanism, and no examples of how the mechanism is proposed to operate on a month-to-month and year-to-year basis. To the extent that these variable O&M costs are indirectly allocated, it is unclear what methodologies Talen is proposing to utilize and whether they are just and reasonable. In addition, Talen has failed to provide examples of how the monthly fuel and variable O&M expense charges will be implemented in order for the Joint Protestors or other interested parties to evaluate the justness and reasonableness of the cost reimbursement mechanism. For the foregoing reasons, Joint Protestors will need discovery to review this proposal to see if it is reasonable under the proposed RMR Rate Schedule. Additionally, the Commission should require Talen to establish a review process to verify the expenses being charged.

G. Talen's proposed RMR cost of service fails to provide assurances that all unfunded reserves accounts shall be included as an offset to rate base.

Talen improperly does not adjust its rate base by offsets for unfunded reserves in the proposed cost of service. An unfunded reserve is one in which a utility accrues an expense which is charged to operations expenses and recovered through a cost-of-service rate, for a future obligation or contingency, but does not escrow the monies received from ratepayers associated with such accrual. Unfunded reserves represent the cost-free capital that the customers have provided to Talen, which has not been set up in an established escrow account.

Talen witnesses do not address unfunded reserves at all in their testimony or in the cost-of-service exhibits. A number of accrued expense items should have their respective unfunded reserves included as a reduction to rate base. Typically, the unfunded reserves associated with those accrued expense items would recorded to the following accounts: (1) Account 228.1 – Accumulated Provision for Property Insurance; (2) Account 228.2 – Accumulated Provision for Injuries and Damages; (3) Account 228.3 – Accumulated Provision for Pensions and Benefits; (4) Account 228.4 - Accumulated Miscellaneous Operating Provisions; (5) Account 242 – Miscellaneous Current and Accrued Liabilities; and (6) Account 232 – Accounts Payable. The types of accrued expenses booked to these accounts typically include:

- Amounts reserved by the utility for losses through accident, fire, flood, or other hazards to the utility's own property or property leased from others, not covered by insurance.

- Amounts charged to FERC Account 925 to meet the probable liability for injuries and damages, such as workers' compensation.

- Amounts charged for FERC Account 926 for Accrued PBOPs and other Employee Benefits.

- Amounts charged to A&G or O&M expense accounts, for example, not limited to, year-end accrued vacation accruals, sick pay accruals, incentive compensation accruals, severance accruals, and deferred compensation.

Talen has not provided financial data or enough documentation to determine what reserve amounts should be included as an offset to rate base. This treatment to require an offset to rate base is consistent with Commission practice.[127]

[127] *See, e.g.*, *Xcel Energy Sw. Transmission Co., LLC*, 149 FERC ¶ 61,182 at P 97 (2014) ("[W]e find that XEST's formula rate template should recognize unfunded operations and maintenance costs reserves as a form of cost-free financial capital to XEST. Utilities may accrue monies through charges to operation and maintenance expense to fund contingent liabilities, and such accrued reserves should be deducted from rate base until they are used to fund the liabilities because such reserves represent a cost-free from of financial capital from customers to utilities, not unlike accumulated deferred income taxes (ADIT) which

H. The Commission should reject several elements of Talen's proposed O&M.

Severance and Retention Packages. Talen's fixed charge rate inappropriately includes the entirety of severance packages as an expense.[128] Since these assets were plant to be decommissioned, these severance packages would have occurred under normal business practices regardless of the implementation of the RMR. The company should only include the incremental costs of any additional costs in the severance packages and expenses that were above any original severance packages which would have taken place on June 1, 2025. Similarly, "retention" packages and expenses included in the fixed charge rate should be amended to reflect only incremental expenses.

Errors in Talen's Inflation Adjustment. Talen's filing has overstated the inflation adjustment. The inflation adjustment should represent that average of the years—not the sum of each year—inflation multiplied by current O&M expenses. Under the company's methodology, the projected expense level exceeds the average level over the time period during which the RMR rate would be in place.

Furthermore, Dr. Schatzki's projected O&M expense included a projected inflation estimate. The projected inflation estimate was developed, in part, based on the projection taken from the Fourth Quarter 2023 Survey of Professional Forecasters, as prepared by the Federal Reserve Bank of Philadelphia. Specifically, Dr. Schatzki utilized Long-Term

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are deducted from rate base. Accordingly, we direct XEST, in a compliance filing, to propose revisions to its formula rate template to credit any unfunded reserves against rate base.").

[128] Exhibit WAG-001 (Schatzki Wagner Direct) at 30:9-12; Exhibit BSH-001 (Schatzki Brandon Shores Direct) at 33:21-24.

Annual Averages Headline CPI for the 2023-2032 period of 2.4% in his calculation.[129] Since this time, more recent quarterly publications have been available. The Second Quarter 2023 Survey of Professional Forecasters reports a projection of 2.33% Long-Term Annual Averages Headline CPI for the 2024-2033 period.[130] Talen's inflation adjustment is based off of outdated estimates and should be recalculated using the latest information available.

CONCLUSION

For the foregoing reasons, Joint Protestors request that the Commission find the Talen Filings deficient and reject them subject to a refiling curing the identified deficiencies. In the alternative, Joint Protestors request that the Commission accept the filing, subject to refund, and set the Talen Filings for hearing.

Respectfully submitted,

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Michael F. Sammartino

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[129] *See* Exhibit WAG-001 at 29:27 – 30:7.

[130] "Second Quarter 2024 Survey of Professional Forecasters," Philadelphia Federal Reserve Bank (May 10, 2024), https://www.philadelphiafed.org/surveys-and-data/real-time-data-research/spf-q2-2024#:~:text=The%20forecasters%20expect%20current%2Dquarter,previous%20estimate%20of%202.1%20percent.

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May 16, 2024

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

H.A. Wagner LLC Brandon Shores LLC	Docket No. ER24-1787, Docket No. ER24-1790 (not consolidated)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on this 16 day of May 2024, the forgoing Motion for Leave to Answer and Answer of the Maryland Office of People's Counsel to Reply Comments of Trial Staff and NBM Marketing LLC were served on each person designated on the official service list compiled by the Secretary in this proceeding pursuant to FERC Rule of Procedure 2010.

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May 16, 2024