UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
NRG Power Marketing LLC	)	Docket No. ER22-1539-000
	)	

PROTEST AND COMMENTS
OF THE
MARYLAND OFFICE OF PEOPLE'S COUNSEL

Pursuant to Rule 211(a)(1) of the Rules of Practice and Procedure[1] of the Federal Energy Regulatory Commission (the "Commission" or "FERC"), the Maryland Office of People's Counsel ("MPC") submits this protest to and comments on the filing made with the Commission by NRG Power Marketing LLC ("NRG PMLLC"), dated April 1, 2022 (the "NRG Filing"), and noticed by the Commission on the same date, initiating this proceeding.

The NRG Filing seeks Commission approval of "cost of service" recovery for the Indian River Unit 4 generating unit ("IR4") under a Reliability Must Run Schedule ("RMR") purportedly in conformity with the procedures of Part V, secs. 113-119 of the Open Access Transmission Tariff ("OATT") of the PJM Interconnection LLC ("PJM"). The NRG Filing requests an effective date of June 1, 2022.

In accordance with the Commission's Rule 214[2], MPC previously filed with the Commission its doc-less motion to intervene in this proceeding, dated April 13, 2022,

[1] 18 CFR § 385.211(a)(1).

[2] 18 CFR § 385.214(a)(3) and (b).

setting forth the basis for its intervention in the proceeding and the necessary contact information. MPC, as well as the PJM Internal Market Monitor ("IMM") and other intervenors in the proceeding, moved to extend the comment filing deadline from April 22, 2022, to May 6, 2022, which motions were granted by the Commission.[3]

INTRODUCTION

NRG's[4] application for RMR treatment seeks to secure wrongfully a windfall for continued operation of an old, if venerable, polluting coal-fired electric power plant. It would do this by misapplying and exploiting the rules and regulations applying at the border—in a kind of limbo space—between the competitive wholesale electric generation market and the regulated provision of transmission grid services. Moreover, affording NRG the relief in compensation that it requests would damage the structure and design of the wholesale electric generation market because it (1) allows NRG to leverage IR4's contribution to grid reliability into a regulated transmission-like excessive payment stream, (2) improperly incents other generators operating in the competitive market in similar circumstances to seek similar relief by prematurely withdrawing from the competitive generation market, and (3) undermines the competitive position of generators remaining in that market.

NRG has operated IR4 for nearly two decades in the competitive wholesale electric generation market, taking the benefits and fully assuming the risks of that

[3] Notice of Extension of Time dated April 20, 2022.

[4] For simplicity, the acronym "NRG" is used in this Protest to refer generically to NRG PMLCC, NRG Energy, Inc, or other NRG affiliates., unless the context requires specific reference to a particular NRG entity.

operation. Now through the NRG Filing, NRG seeks to transform IR4 into a newly minted regulated asset, with recovery of its investment under cost-of-service principles, as though, contrary to the facts, IR4 had never before been operated in the competitive generation market and, under the rules of that marketplace, had not previously, directly contrary to the full write-off it did recognize, of its prior investment in IR4 that it now seeks to recover from captive ratepayers through transmission-related regulated rates. In doing this, NRG seeks to exploit the leverage it has because continued operation of IR4 is deemed necessary to keep the regulated transmission grid from violating reliability criteria. NRG's proposition to the Commission, the States, and affected electric consumers—boiled down to its essence—is that absent securing the windfall of recovery of its already written off investment, it will retire the plant, thereby putting at risk operation of the electric grid. The Commission cannot and should not endorse this.

NRG has not shown, as it is statutorily required to do so under Section 205 of the Federal Power Act ("FPA"), that the proposed Cost of Service Recovery Rate set forth in its RMR Rate Schedule is just and reasonable. NRG's filing is significantly incomplete and fails to provide any audited financial reports and cost statements to show the source of cost inputs for its cost of service study[5] and to demonstrate how the RMR Rate Schedule inputs are consistent with and follow the Commission's original cost accounting and ratemaking principles that are specified by the Commission's Uniform

[5] *See* Cost of Service Study, Exh. NPM-003.

System of Accounts ("USofA").[6] NRG has failed to reconcile its cost-of-service ratemaking inputs to Indian River's, NRG PMLLC's, NRG Energy Inc.'s, or any other entity's audited financial reports. Further, NRG's filing fails to include adequate information substantiating that the specific costs it seeks to recover in the RMR Rate Schedule are just and reasonable. Finally, NRG failed to explain what procedures will be in place during the IR4 RMR Term to ensure that there is no over or double recovery of costs among the three RMR Rate components contained in the RMR Rate Schedule.

As described in Parts I and II below, the NRG Filing is contrary to and mis-states Commission precedent regarding the permissible level of revenue requirements due under a RMR arrangement under the PJM OATT. Further, as Part III below explains, even if it is evaluated in a traditional manner under the Commission's rules under FPA Section 205 as a cost-of-service tariff filing, the NRG Filing is woefully deficient. MPC is also deeply concerned that the planning procedures and process followed by PJM have serious deficiencies, enabling here NRG's request for payment by electric consumers of over $315 million in fixed payments over approximately four years and seven months, plus additional items of capital recovery—costs that could have been obviated or reduced by the pro-active construction of a transmission line and other transmission related fixes for approximately $40 million, described further below in Part IV. Under current circumstances, it appears that electric consumers will wind up being responsible for the cost of both NRG's RMR arrangement and the transmission line.

[6] 18 C.F.R. Part 101 (2022).

Presuming that the grid reliability violations resulting from IR4's retirement are adequately demonstrated and addressed if IR4's operation is continued, MPC does not oppose payment to and recovery by NRG of the actual, legitimate costs of operating and maintaining IR4 during the future periods of its needed operation. MPC, however, strongly objects to NRG's recovery of any payments from electric consumers in excess of those costs.

The NRG Filing on its face is seriously deficient and merits rejection by the Commission. In light of the impending June 1 deadline for deactivation of IR4 proffered by NRG absent a RMR arrangement of some sort, and PJM's finding that IR4's continued operation is needed for grid reliability, MPC, however, requests, albeit under duress, that the Commission accept NRG's filing to become effective June 1, 2022, subject to refund, and set the issues raised in this protest for expedited hearing.

BACKGROUND

1. The history of Indian River Unit 4 (IR4) under NRG's ownership.

NRG Energy, Inc.[7] is the owner and operator of the IR4 electric generating plant. IR4 began operation in 1980, is coal-fired, and has a reported electric generating capacity of 410.0 megawatts ("MW") (summer rating). It is located in Middleboro, Sussex County, in southern Delaware, about half-way down the Delmarva Peninsula. NRG also owns and operates adjacent to IR4, Unit CT10, an approximately 16.1 MW (summer rating) oil-fired combustion turbine electric generating unit commissioned in 1967, which

[7] Ownership is through one or more of affiliates, and with NRG PMLLC. As noted above, these entities are collectively referred to in this Protest below as "NRG" unless the context requires otherwise.

NRG has not included in the NRG Filing. IR4 and Unit CT10 are interconnected with and deliver their electric output to the electric transmission system of Delmarva Power and Light Company ("DPL"). DPL, in turn, is the transmission provider supplying electric transmission service to end-use customers within its service territory in the States of Delaware, Maryland and Virginia. It is these electric consumers who will be ultimately responsible for the costs of the RMR arrangement sought by NRG as ultimately approved by the Commission.[8]

NRG (or its predecessor prior to bankruptcy in 2003) acquired IR4, Unit CT10, and three other coal-fired operating generating units (Units 1 (80 MW), 2 (80 MW) and 3 (155 MW)) located at the same site from DPL in 2001. Two years later, NRG PMLLC's predecessor parent and certain of its affiliates filed for Chapter 11 bankruptcy in 2003 and reorganized pursuant to an order of the bankruptcy court confirming NRG parent's bankruptcy reorganization plan, which became effective on Dec. 5, 2003.[9] IR4 was included in the assets subject to the bankruptcy reorganization and its ownership was retained by the NRG successor entity(ies) emerging from bankruptcy.[10] NRG subsequently retired Indian River Units 1, 2 and 3 from operation and shut them down in

[8] PJM OATT, Part V, §120. The transmission facility enhancements needed to resolve the reliability violations created by IR4's retirement appear to be entirely on the DPL transmission grid and for which DPL will be assigned financial responsibility. *See* footnote 19, *infra*. Hence, per the cited OATT section, the costs of the RMR arrangement would be fully allocated to the transmission rate charge for transmission customers receiving service in DPL's Zone.

[9] *In re: NRG Energy, Inc. et al.*, Chapter 11, Case No. 03-13024 (Bankruptcy Ct. S.D. N.Y.), Order (dated Nov. 24, 2003).

[10] *In re: NRG Energy, Inc. et al.*, Chapter 11, Case No. 03-13024 (Bankruptcy Ct. S.D. N.Y.), Disclosure Statement, at 16 (Oct. 10, 2003).

2011, 2010 and 2013, respectively.[11] NRG continued and continues to operate IR4 to the present in the competitive wholesale electric markets administered by PJM, but now seeks through the NRG Filing to do so under a RMR arrangement. Absent the RMR arrangement, NRG threatens to permanently shut down and retire the unit.

2. NRG sought the benefits and assumed the risks of the competitive wholesale electric market in acquiring and operating IR4.

From the inception of NRG's ownership to the present under the authority of NRG's FERC granted market-based rate authorizations, IR4 (and the other generating capacity located at the same site) have participated as generating resources in the competitive wholesale electric markets administered by PJM Interconnection, LLC ("PJM"), deriving revenue from the wholesale competitive power markets or bilateral supply contracts and **not** from cost-of-service determined regulated rates.[12] Similarly, NRG's top management generally has described the company's overall business model and investment expectations to be determined by market competition and not regulation. Company management, describing the NRG's business model in written testimony submitted to the Energy Subcommittee of the US House of Representatives, has stated, for example, that:

> As a purely competitive company with no captive ratepayers, NRG and its shareholders bear the risks (and the profits or losses)

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[11] *See, e.g., NRG Agrees to Shut Down Third Del. Coal Unit*, Electric Power Daily (July 19, 2010), p. 5; NRG 2010 Form 10-K, pp. 83, 175; NRG 2013 Form 10-K, at 88.

[12] With the exception that IR4 had been collecting cost-based rates for reactive power service and voltage control, In Docket No, ER22-1540, NRG proposed to remove IR4's revenue requirement from this tariff schedule effective June 1, 2022. Based on MPC's preliminary review, this is not material to the discussion in text and raises other concerns about the reliability services that IR4 will actually provide during the RMR term.

> associated with its participation in the wholesale and retail electricity markets. We believe that fair and robust competition in the electric sector is the best means of delivering value to consumers….
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> NRG's business is premised on one key concept; that fair and robust competition, and not monopoly, is the best tool for providing value to consumers. As a purely competitive company with no captive ratepayers, NRG and its shareholders bear the risks and the economic consequences—positive or negative—associated with its participation in the wholesale and retail electricity markets. As this Subcommittee has heard in previous hearings, some companies are seeking corporate bailouts to undo the results of competition in the electricity markets. NRG's position is different. We urge this Subcommittee to ensure that organized markets utilize competition to drive investment in energy infrastructure, lower costs for consumers and provide reliable electricity to power the economy. [[13]].

Like any investment in assets deployed into a truly competitive market, IR4 and its economic prospects over the period of its ownership by NRG have ebbed and flowed with changes in the surrounding market context. Early in its period of ownership, NRG was bullish about IR4 and its sibling plants on the Delmarva peninsula, stating, for example, that:

> NRG's Northeast region assets are located in or near load centers and inside chronic transmission constraints such as New York City, southwestern Connecticut and the Delmarva Peninsula. Assets in these areas tend to attract higher capacity revenues and higher energy revenues and thus present opportunities for repowering these sites. The Company has benefited from the introduction of capacity market reforms in both the New England Power Pool, or NEPOOL, and PJM.[[14]]

[13] Testimony of Christopher Moser, senior VP of Operations for NRG Energy, Inc., Hearing before the Subcommittee on Energy of the Committee on Energy and Commerce, U.S. Congress, House of Representatives, "Powering America: Examining the Role of Financial Trading in the Electricity Markets", Nov. 29, 2017, 115th Congress Serial No. 115-81, at 101-102 (Nov. 29, 2017).

[14] NRG Energy, Inc., *2008 Form 10K*, at 27.

The electric transmission constraints of the electric grid on the Delmarva peninsula, owing to its unique geography, are a recurring, long-standing problem.[15] NRG, as reflected in the above-cited language, expressly sought to purchase and invest in IR4 and its sibling plants, incented by the potential upside afforded by, but also subject to the down-side risks of, the benefits of their location and operation in the context of a competitive wholesale electric generation market. Nevertheless, subsequent trends in the wholesale power markets adverse to and affecting the Indian River Generating Facility caused NRG in 2013 to declare an accounting impairment of $459 million against the

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[15] *See*, *e.g*., Order, 103 FERC ¶ 61,163 (2003); Order, 104 FERC ¶61,241 (2003); Transmission Congestion on the Delmarva Peninsula, Docket No. PA03-12, *Presiding Judge's Proposed Findings of Fact and Recommendations*, 105 FERC ¶ 63,004 (2003); *Order Granting Transmission Rate Incentive, Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 (2008), P. 8-10; US Dep. of Energy, *National Electric Transmission Study*, (2009), p. 40; US Dep. of Energy, *National Electric Transmission Congestion Study* (2015), at xi (in a study of national conditions, identifying the Delmarva Peninsula as consistently a "congestion hot spot" due to transmission constraints); Maryland Department of Natural Resources, Power Plant Research Program, *Maryland Power Plants and the Environment* (2017), at 40 ("The Delmarva Peninsula, consisting of Maryland's Eastern Shore, Delaware, and a portion of Virginia, experiences high [electric] congestion costs due to the isolation of the transmission system.").

asset.[16] NRG declared a further accounting impairment against the Indian River generating plant in 2017 of $36 million.[17]

3. NRG's request for RMR treatment improperly seeks to shift to ratepayers risks and costs that it had assumed.

With its filing for an RMR arrangement in this proceeding, NRG now seeks to divorce and insulate its decisions about IR4 from the competitive market forces and paradigm it previously embraced. Through the proposed RMR arrangement, NRG looks to return to cost-of-service regulation and recovery of and on its past investments. NRG made these investments in contemplation of and while operating in the competitive wholesale generation market. It now relies in its filing with the Commission on a confection of the accounting of the plant's costs, as though the plant was and had always been a fully regulated asset, erasing the asset's prior material accounting impairments made in real time in full acceptance of the then applicable market-related accounting, reporting and risk allocation rules.

[16] NRG Energy, Inc., 2013 Form 10K, at 147. ("2013 Impairment Losses Indian River … The Company's revised views of projected profitability for Indian River resulted in a significant adverse change in the extent to which the assets are expected to be used. As a result, the Company considered this to be an indicator of impairment and performed an impairment test for these assets under ASC 360, Property, Plant and Equipment. The carrying amount of the assets was lower than the future net cash flows expected to be generated by the asset, considering project specific assumptions for long-term power pool prices, escalated future project operating costs and expected plant operations. As a result, the assets are considered to be impaired…. The Company recorded an impairment loss related to Indian River in the fourth quarter of 2013 of $459 million."). This exceeds by $40 million the amount NRG's witness claims that NRG has invested in IR4 since its 2003 bankruptcy and presumably comprising the vast majority of the amount of IR4's claimed gross plant used to calculate rate base in support of NRG's proposed revenue requirements under the RMR arrangement. *See* NRG Filing, Exhibit No. NPM-001, at 15 of 43, line 18; Exhibit No. NPM-003, at 1, line 2, Period II.

[17] NRG Energy, Inc., 2017 10K, at 108.

In initiating the procedures of the PJM OATT to secure a RMR arrangement for IR4 and leading up to the instant NRG Filing, NRG notified PJM by correspondence dated June 29, 2021, that it intended to retire IR4, effective May 31, 2022, due to the unit's asserted "uneconomic operations." As provided in the OATT, PJM responded thirty days later stating that it "had identified reliability violations resulting from the proposed deactivation of [IR4] absent upgrades to Transmission System which are currently being proposed."[18] PJM staff subsequently made presentations to the PJM Transmission Expansion Advisory Committee ("TEAC") describing the reliability violations and recommending transmission solutions to resolve those violations created by the retirement of IR4.[19] The one larger cost, longer duration necessary transmission solution identified by PJM to resolve the grid reliability violations absent IR4's continued operation, entails a rebuilding of the Vienna (MD) – Nelson (DE) DPL 138kV transmission line owned and operated by DPL. PJM estimates the cost of this solution at $38.5 million with an estimated in-service date of December 31, 2026.[20]

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[18] PJM letter to Indian River Power, LLC, dated July 30, 2021, attached to the NRG Filing.

[19] PJM, TEAC, *Generator Deactivation Notification Update (*August 10, 2021), at 17-23 (showing multiple required transmission solutions at higher cost and delayed in-service dates from those identified in the August 31, 2021 presentation); PJM TEAC, *Generator Deactivation Notification Update* (Aug. 31, 2021), at 22-28 (showing all other required transmission solutions, with the exception of the cited required 138 kV line rebuild, capable of accomplishment by end of 2022 and costing $2.15 million in aggregate). *See also* PJM letter to Indian River Power, LLC (July 30, 2021), attached to the NRG Filing.

[20] *See supra*, note 19.

Nine months later, on April 1, 2022, NRG filed the NRG Filing with the Commission, proposing to extend IR4's operation, conditioned on FERC approval of its requests of the following:

(i) entry of a RMR agreement for IR4, subject to early termination upon satisfaction of certain notice requirements, with a term of four years and seven months (extended from May 30, 2022, its requested initial effective date, presumably until the Vienna (MD)-Nelson (DE) transmission line "solution" can be put into service at the end of 2026).

(ii) payment to NRG, during the RMR agreement term, of a monthly fixed charge of $5,828,312.83,[21] inclusive of cost-of-service determined revenue requirements for depreciation and a rate of return on past investments—an asserted net rate base of $260.5 million[22]—or a cumulative payment of approximately $70 million per year and $315 million over the stated 4 year and 7-month term of the RMR IR4 agreement.

(iii) additional recovery by NRG of an estimated $36.2 million of project investment expenditures for repairs, replacements and additions required to comply with applicable regulatory reliability rules and maintenance deemed necessary by and to the extent incurred by NRG during the term of the RMR agreement to keep IR4 in operation; and

(iv) recovery by NRG of fixed and variable expenses incurred to operate the plant during the RMR agreement's term.

The cumulative fixed project investment related and other fixed charges proposed to be incurred by NRG under the term of the RMR agreement are more than eight times greater than the cost of the transmission solution which would eliminate the need for the RMR agreement. It is also a multiple of the estimated "going forward" operation and

[21] NRG Filing, Exhibit No. NPM-001, at 12 of 43.

[22] NRG Filing, Exhibit No. NPM-003, at 1 of 4, line 2, Period II.

maintenance expenses comprising IR4's "operating costs" related to running the plant on a going forward basis. If approved by the Commission as proposed by NRG, ratepayers in Delaware, Maryland, and Virginia will wind up paying for both past and future investment in IR4 as well as for the rebuilt transmission line intended to resolve the grid reliability violations otherwise created by a shutdown of IR4.

ARGUMENT

I. NRG's request to recover through the RMR the investment it made during the IR4's period of market operation is contrary to PJM market rules and FERC precedent and policy.

A. The PJM OATT precludes NRG's request for recovery of and on its prior investment in IR4.

NRG should not recover, either through depreciation charges or return on a rate base comprised of prior investment, of its prior, now sunk, investment in IR4. Nor should it do so when it has previously recognized full impairment for accounting purposes of that investment. In seeking that recovery in its filing, NRG misconstrues and mis-applies the language of the PJM OATT applicable to RMRs. The PJM OATT has two alternate procedures for determining the rates for compensation of a generation owner seeking to de-activate an electric generating resource which PJM has determined is needed to avoid a grid reliability violation—the predicate to entry into a RMR arrangement for the resource. The two options—with significant procedural differences depending on which is selected—are both delimited by providing generally only for the recovery under the RMR of the affected generating unit's "operating costs" or "going forward" costs and not its sunk, embedded investment.

The first option contained in OATT Part V, Sections 114 and 115, provides for a payment by PJM Settlement to the generation owner of a "Deactivation Avoidable Cost Credit" ("DACC"). The DACC allows the generation owner to recover the "avoidable costs" or "going-forward" costs of operating the affected generating unit. Recovery is reviewed and vetted by the IMM with the right of the IMM to petition the Commission in the event it disagrees with the generator owner, plus an adder which increases during each year of the term of the RMR arrangement, and less the net revenues received from the operation of PJM's administered markets on account of the unit's operation. Section 115 specifies with particularity the components of "avoidable cost" that the generator owner can recover.[23] It also caps the incremental capital investment made during the RMR term and allowed to be recovered at $2 million (described in the OATT as the Avoidable Project Investment Rate ("APIR"))[24]. Action under this option under the OATT is akin to a formula rate and does not require for its effectiveness the full vetting of Commission review and approval, as would be the case if the Commission were to decide a fully regulated cost of service-based rate under the FPA.

Alternatively, Section 119, opted for by NRG in its filing, provides generally for a filing by the generation owner for Commission approval of "a cost of service rate to

[23] The section generally defines "avoidable expenses" as "incremental expenses directly required for the operation of a generating unit proposed for Deactivation that a Generation Owner would not incur if such generating unit deactivated on its proposed Deactivation Date rather than continuing to operate beyond its proposed Deactivation Date."

[24] PJM OATT, Part V, §115.

recover the *entire cost of operating the generating unit*…"[25] (emphasis supplied), as an alternative to the very prescriptive formula rate type provisions of the first option provided for under the OATT. Section 119 provides flexibility, cabined by the Commission's review and approval of variations from the prescriptive provisions of sections 114-115, including, for example, Commission approval of a variance from the provisions of sections 114 and 115 for the generation owner to exceed the $2 million APIR cap for incremental capital expenditure during the RMR term.

PJM OATT, Part V, generally allows only for recovery of avoidable incremental expenses and investment, less net operating revenues during the period of RMR service. Part V does not permit the recovery of costs that would have been incurred if the unit deactivated and never provided RMR service. The formula rate also provides for an incentive adder based on the term of RMR service. The goal of the tariff language is to ensure that a generation owner who operates a unit past its intended retirement date for reliability reasons is compensated for all the incremental costs and investments that it incurs in order to provide that service. Section 119 allows recovery under a tariff filed at the FERC of operating costs, including a return on and of that incremental, going-forward investment needed to continue operating during the period of RMR service, but does not provide for an incentive adder. The tariff's goal is *not* to provide the generation owner an opportunity to earn windfall profits or recover otherwise unrecoverable costs because the unit retirement causes a reliability problem.

[25] Use of the term "operating cost" is significant. There is no express reference in the section, contrary to how NRG seeks to interpret the provision, authorizing the recovery of sunk, embedded costs.

B. NRG's request to recover its prior investment in IR4 is not supported by applicable FERC precedent.

The NRG Filing mis-interprets the cited provisions of the PJM OATT providing for and defining the compensation due to generating units subject to an RMR arrangement. In the context defined by the PJM OATT, NRG seeks to recover its now-sunk embedded capital investment, claiming that this is supported by practice under the PJM OATT and by FERC precedent construing RMR arrangements in PJM and other RTOs/ISOs. These claims are simply not the case.

First, FERC has stated that the outcome for RMR type arrangements is different for each RTO/ISO and depends on the provisions of the particular RTO/ISO's tariff and overall market design.[26] Accordingly, the language of the PJM OATT discussed above is the primary and deciding context for evaluation of the revenue requirements sought by NRG for IR4.

Second, specifically in PJM, FERC has set for hearing at least twice the question of the quantum of recovery under a RMR arrangement and whether it permits recovery on and of prior capital investment, but has never finally decided the issue.[27] The revenue requirements finally approved by FERC for RMRs—those covering affected generating units operating in PJM and opting for the section 119 alternative—generally resulted

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[26] *PSEG Energy Resources & Trade, LLC, et al.*, 111 FERC ¶ 61,121, P 22 (2005), *citing Milford Power Company*, LLC, 110 FERC ¶61,299, P 71 (2005).

[27] *PSEG Energy Resources & Trade, LLC, et al.*, 111 FERC ¶ 61,121, P 21(2005) (affecting certain generating units at PSEG's Sewaren and Hudson Stations); *GenOn Power Midwest, LP*, 140 FERC ¶ 61,080, P 35 (2012) (affecting GenOn's Elrama Unit 4 and Niles Unit 1).

from "black-box" settlements by the parties, in filings expressly stating that the settlements would have no precedential value.[28] In the *GenOn* case, FERC approved the contested settlement rate based on its general authority to approve settlements and expressly did not decide the question in favor of NRG's position taken in this proceeding. Notably, the settlement rate in the *GenOn* case was supported by an affidavit filed on behalf of the RMR applicant asserting that the settlement rate was very close to a rate which entailed no recovery of or on prior capital investment by the plant owner.[29]

As stated previously, citation to FERC RMR precedent from other RTOs/ISOs is not binding or applicable in this proceeding given differences in the market designs of each RTO/ISO. In approving the rules and framework adopted by certain other RTOs/ISOs to address RMR-type circumstances on a comprehensive basis (unlike the individual application here), FERC has nevertheless stated that the revenue requirements of a RMR contract may be set at the affected generating unit's "avoidable" or "going forward" costs or other rate if agreed by the applicant with the intervening parties provided the ISO/RTO RMR requirement is not "mandatory" on or an "obligation" of the

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[28] *See, e.g., Exelon Generation Co., LLC*, 132 FERC ¶ 61,219 (Sep. 16, 2010) (ER10-1418) (affecting the Cromby Unit 2 and Eddystone Unit 2, located in southeastern Pennsylvania), *Order Approving Settlement*, 135 FERC ¶ 61,190 (May 27, 2011); *GenOn Power Midwest, LP*, 144 FERC ¶ 63,001 (2013) (Report to Commission of Contested Settlement); *Order Approving Contested Settlement Agreement*, 149 FERC ¶61,218 (2014); *RC Cape May Holdings, LLC*, 159 FERC ¶ 62,088 (2017) ("RC Cape May") (accepting and suspending rate schedule subject to refund and establishing hearing and settlement procedures) (affecting the B.L. England Generating Station); *RC Cape May Holdings, LLC*, 162 FERC ¶ 61,194 (2018) ("RC Cape May II") (accepting an offer of settlement).

[29] *GenOn Power Midwest LP, Order approving Contested Settlement Agreement*, 149 FERC ¶ 61,218, PP 17, 34 (2014).

generator under the ISO/RTO rules.[30] By contrast to the circumstances in CAISO and NYISO addressed in other decisions of FERC regarding RMR arrangements, the PJM RMR rule, by its terms, does not appear to be "mandatory." It provides that the generator, "[r]egardless of whether the Deactivation of the generating unit would adversely affect the reliability of the Transmission System… *may* deactivate its generating unit, subject to the notice requirements in section 113.1 [of the OATT]."[31] Hence the Commission precedent from certain other ISOs/RTOs, even if deemed superficially applicable through common utilization of the RMR label, does not endorse NRG's asserted foundation for defining the revenue requirements of its proposed RMR arrangement, seeking recovery of and on prior capital investment for a generating unit located in the PJM footprint.[32]

Third, it is notable that NRG itself, in other circumstances, has argued that the compensation due under a RMR arrangement for another generator on account of its prior

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[30] *California Indep. Sys. Operator Corp.*, 168 FERC ¶ 61,199, P 84 (2019). *See also, N.Y. Indep. Sys. Operator Corp.*, 150 FERC ¶ 61,116, P 17 (2005), *order on compliance and reh'g, N.Y. Indep. Sys. Operator Corp.*, 155 FERC ¶ 61,076, P 84 (2016) (order on compliance and rehearing); *Midcontinent Indep. Sys. Operator, Inc.*, 148 FERC ¶ 61,057, P 84 (2014).

[31] (Emphasis supplied)._As noted previously and in the NRG Filing, Section 113.1's notice requirement provides that a generation owner seeking to deactivate a generating unit must provide at least 90 days advance notice to PJM of the date it intends to deactivate its generating unit.

[32] MPC emphasizes that prudence, corporate governance and fiduciary rules and economic rationality are constraints on NRG's actions in decisions relating to the plant; applicable independent of FERC's view of whether the PJM RMR rule is "mandatory" or not. MPC does not object to payment to NRG of the legitimate and documented avoidable costs of operating IR4, provided the grid reliability need of continued operation of IR4 is established. Economic principles provide that if NRG can cover its costs of operation, a shutdown is not warranted. Such a decision may also be objected to on other grounds—for example, the possible undue and anti-competitive benefit accrued by NRG's other generating plants operating in PJM, some within the same DPL locational deliverability area. They could be sufficient to trigger intervention of the US DOE under section 202 (c) of the Federal Power Act.

capital investment in a generating unit seeking RMR treatment should be limited to recovery of only that investment, reduced by prior write downs due to accounting impairments, if the generator continued to operate the unit without a RMR following recognition of the impairment or an application pending to secure one.[33] Here, similarly, NRG operated IR4 for many years in the competitive generation market, accepting its outcomes. This operation followed NRG's recognition of an accounting impairment of its capital investment in the generating unit but before seeking to deactivate or seeking an RMR arrangement. Such treatment accords with the reasonable investment backed expectations of the generator owner and its investors. NRG's same argument should apply to its own actions in this proceeding.

II. NRG's recovery of its prior investment through an RMR would exacerbate the adverse impacts of RMR arrangements on the structure of PJM's competitive wholesale electric power markets.

NRG's filing is not only contrary to the terms of the PJM OATT; it also is seriously deficient on Commission-endorsed policy grounds. RMR arrangements provide for RTO/ISO control of a generating unit's operation and its continuity of operation so as to avoid a transmission system reliability violation. They lie in the limbo space between two regulatory paradigms: the first, the competitive wholesale electric generation market where revenues are determined by competition among multiple, diversely owned

[33] *See* Reply Brief of NRG Power Marketing LLC in FERC Docket No. 18-1639 (Nov. 16, 2018) (referring to Exelon's position to the contrary in the Constellation Mystic Power LLC RMR proceeding). MPC submits that the circumstances of that case in a different ISO with different market rules and FERC's ruling on the question in that case are distinguishable, for other reasons as discussed elsewhere in this Protest, from the matters addressed here.

generating units offering prices into a market; and, the second, transmission service provided on a monopoly basis where revenues are determined by regulated cost of service.

Generators availing themselves of the arrangement do it by exiting the conditions of competition in the wholesale market, thereby converting their source of revenue from the volatile, riskier payments made in competitive markets to the assured payment stream paid for transmission or transmission equivalent services. They can do it because their generating units provide necessary benefits to the transmission grid. This gives them leverage to use the threat of withholding of continued operation to extract a more favorable regulated payment stream as a "transmission equivalent" asset.

Perverse and inefficient incentives to anti-competitive behavior can arise in these circumstances, even while acknowledging the need to have generators continue operation if truly needed for grid reliability when they are unwilling to operate in the competitive generation market. Generators can see the regulated RMR rate, if too easily available and/or excessive in amount, as an incentive to exit the competitive generation market prematurely, undermining competition in the generation market by reducing the diversity and amount of competitively provided supply. The departure of a generating unit from the market, in turn, can have follow-on adverse effects on the market which it leaves (or strategic benefit to the departing unit's owner). These adverse effects can occur either through market price suppression, because the revenue for the RMR unit's output is no longer tethered to the market price, or due to reduced dispatch of the departing generator by direction of the RTO under the RMR arrangement, indirectly benefitting the same owner's other units competing in the same area, through price inflation due to reduced supply affecting the locational prices paid to the nearby units remaining in the competitive market-place.[34]

Given like considerations arising in other RTOs/ISOs, the Commission has frequently observed that RMR arrangements must be measures of "last resort." [35] PJM-specific analysis also arrives at the same conclusions.[36] In order to curb the perverse incentives and damage to the competitive generation market arising from RMR arrangements and to make the measure truly one of last resort:

> (i) there must be rigorous scrutiny of the claimed reliability need addressed by a generator seeking RMR treatment for a unit;
>
> (ii) there must be pro-active planning by the RTO/ISO for the possibility of RMR eligible units to minimize the circumstances when a RMR is deemed necessary; and
>
> (iii) the compensation due a RMR unit under a RMR arrangement should be minimized to cover legitimate otherwise avoidable operating costs of the unit and no more.

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[34] NRG owns nearby generation on the Delmarva Peninsula, including the 167 MW oil-fired Vienna, Maryland power plant. MPC is not aware of any review or conclusions of the strategic adverse market competitive effects of IR4's retirement or operation on other generators in the Delmarva peninsula as a RMR unit.

[35] *See, e.g., N.Y. Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116, at 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").

[36] PJM IMM, *State of the Market Report* (2021), vol. 1. p. 42; vol. 2, pp. 323-325 (2022); Synapse Energy Economics, Inc., *PJM System Planning Enhancements for the 21st Century* (2011) at 9.

The PJM OATT rules for determining eligibility and the structure of RMR arrangements must adhere to and be interpreted in light these standards; otherwise, the arrangement, instead of "last resort," becomes or risks becoming an end-run that undermines the competitive generation market. Rejection of NRG's request to recover its sunk investment—because it is not an "operating cost" under PJM OATT, sec. 119—is a necessary part of the overall structure of the PJM market rules required to keep RMRs as a "last resort" measure consistent with the Commission's general views about the role of RMRs.

III. NRG's alleged "cost of service" to support its requested revenue requirement under the RMR is deficient on multiple grounds.

NRG opted to make a filing under section 205 of the FPA of its "cost of service" as delimited by PJM OATT Part V, section 119. Notwithstanding MPC's arguments above regarding the permissible scope of recovery under PJM OATT, Part V, Section 119, as the applicant in this proceeding, NRG bears the affirmative burden of supporting each component of its rate request; and it bears the risk of gaps in the documentary support for its filing.[37] NRG has failed to carry that burden. Therefore, even if the Commission rejects Parts I and II of this protest, it should reject NRG's proposed cost-of-service study.

This part of MPC's protest addresses the following issues:

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[37] *See Nantahala Pwr. & Light Co. v. FERC*, 727 F.2d 1342, 1351 (4th Cir. 1984) ("A utility bears the burden of justifying each component of a rate increase ... under § 205(e) of the Federal Power Act. Because a regulated utility is the party with access to the necessary information, it bears the risk of an undeveloped or inconclusive record.").

- NRG's filing fails to meet the Commission's ratemaking cost support requirements for electric cost of service rate schedules (including Tax Cuts and Jobs Act of 2017 ("TCJA"), Accumulated Deferred Income Taxes ("ADIT"), federal and state income tax allowance ("ITA"), accounting for impairments) (Part III.A);

- NRG's Monthly Fixed-Cost Charge Rate contains cost data that is not representative of costs expected during the IR4 RMR Term (Part III.B);

- NRG's filing improperly may allow NRG to over-recover or double recover just and reasonable costs during the IR4 RMR Term (Part III.C);

- NRG's Proposed Monthly Fixed-Cost Charge is Subject to Multiple Deficiencies and should be subject to a True-up Mechanism (Part III.D);

- NRG's Accounting Bases for its Filing are Subject to Multiple, Severe Deficiencies (Part III.E): Rate Base (subpart E.1); Period II Depreciation and Amortization (subpart E.2); ADIT (subpart E.3).

- NRG's Proposed RMR cost of service Fails to Provide Assurances that All Unfunded Reserves Accounts Shall be Included as Offsets to Rate Base (Part III.F).

- NRG has failed to support its overall requested rate of return and capital structure (Part III.G).

- Deficiencies in the Support for NRG's Total Overall Cost-of-Service (NPM-003, Statement 1, p. 1 of 1) (Part III.H). (Operation and Maintenance (O&M) Expense (subpart H.1); Administrative and General ("A&G") Expense (subpart H.2); Depreciation Expense (subpart H.3); Taxes Other Than Income Taxes (subpart H.4); State and Local Income Taxes (subpart H.5)).

- Project Investment Recovery and the Tracker Mechanism for Its Recovery Suffers from Multiple Infirmities (Part III.I).

- NRG has failed to support the Cost Reimbursement Mechanism to Recover IR4's Variable Operations and Maintenance costs or provide a review process for the mechanism (Part III.J).

A. NRG's filing Fails to Meet the Commission's Ratemaking Cost Support Requirements for Electric Cost of Service Rate Schedules.

As previously noted, NRG has the obligation under section 205 of the FPA to show that the costs it seeks to recover are just and reasonable. While NRG includes a traditional cost of service analysis for IR4[38] in its filing, the study universally fails to include support for the data inputs regarding the source and validity of the cost data inputs and the ratemaking methodologies and principles used to develop the cost-of-service study inputs.

NRG's proposed cost of service RMR Rate Schedule contains numerous material and glaring omissions. Included below are examples of important and necessary data omitted from NRG's cost of service filing. Some of these omissions and their implications for the overall filing are discussed in detail further below. Additional data omissions are addressed later in this Protest.

NRG failed to address the effect of the TCJA on its ADIT balances and the amount of excesses and deficiencies in ADIT resulting from the change in the corporate federal income rate. Regarding ADIT balances used as adjustments to rate base in the Monthly Fixed-Cost Charge Rate calculation, NRG has failed to address whether amortization of any resulting ADIT excesses or deficiencies should be factored into the calculation of the federal income tax allowance ("ITA"). In addition, NRG failed to

[38] *See* Exh. NPM-003.

identify ADIT resulting from other book-tax differences, that is, book-tax differences other the differences between the book and tax bases of net utility plant.

Another ADIT omission from NRG's proposed RMR Rate Schedule is its failure to identify and factor into the RMR rate the ADIT resulting from the Monthly Project Investment Tracker costs and the fuel and variable operations and maintenance ("O&M") costs recovered via the reimbursement mechanism. To the extent costs recovered under either of these two cost of service RMR Rate Schedule components result in ADIT, NRG needs to identify the resulting ADIT and explain how it proposes to reflect the ADIT amounts in the RMR Rate Schedule.

NRG failed to include documentation of the formula used to compute the federal and state ITA included as a cost input to its cost-of-service study for the Monthly Fixed-Cost Charge Rate.[39] Also, NRG acknowledged in its filing that it is a pass-through entity and does not pay income taxes[40] but failed to explain and justify why it is appropriate for IR4 to collect the ITA as part of its Monthly Fixed-Cost Charge.

NRG's filing discussed the history of the ownership of Indian River IR4, bankruptcy and reorganization proceedings involving IR4 and the use of Fresh Start accounting, and certain unspecified impairment write-downs reflected on its books under generally accepted accounting purposes. As part of its cost-of-service study[41], NRG provided unsupported book and tax net utility plant balances at December 31, 2021

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[39] Exh. NPM-003, Statement 1, at 1, Line 6.

[40] Exh. NPM-001 at 22: 3-11.

[41] Exh. NPM-003.

(Period I test period) based primarily on utility plant additions occurring after NRG's emergence from bankruptcy in December 2003, consisting of about $381 million of additions to meet emission standards and about $26 million of other utility plant additions ("post-2003 utility plant additions"). NRG included in the cost-of-service study inputs for the accumulated book and tax depreciation and amortization balances which are not supported by any worksheets or audited financial reports.

B. NRG's Monthly Fixed-Cost Charge Rate contains cost data that is not representative of costs expected during the IR4 RMR Term.

NRG's filing fails to provide a sufficient explanation and examples of how the Monthly Project Investment Tracker Rate and fuel and variable O&M Rate recovery mechanism will be computed and billed monthly along with true-up mechanisms.

NRG's filing includes repeated claims that the Period II test period includes costs that are representative of the costs that will be during the IR4 RMR Term (*i.e.*, June 1, 2022 through December 31, 2026). For purposes of the calendar year 2022 Period II test period, NRG made very few adjustments in deriving its Period II costs. For the Period II test period, NRG made one adjustment to O&M Expense on its Statement 1: Total Overall Cost of Service[42] and another on Statement 2: Rate Base, Return and Income Tax Allowance at December 31, 2021[43], as adjusted, to Line 4, Prepayments and Inventories, for coal inventory for the RMR service. However, the Period II Test period fails to include any adjustments to the book cost of the Accumulated Depreciation and

[42] (Exh. NPM-003, Statement 1, p. 1, Line 1).

[43] (Exh. NPM-003, p. 1 of 4).

Amortization and to ADIT applicable to the book-tax basis differences for net book and net tax utility plant at December 31, 2022.[44] This practice will result in an overstatement of rate base during the IR4 RMR Term since NRG's cost of service study fixes the Net Plant and ADIT book balances at December 31, 2022, for the entirety of the IR4 RMR Term. This result clearly shows that the Period II costs as derived by NRG does not represent the fixed costs expected to be incurred during the 4 years and 7 months that the IR4 RMR Rate Schedule will be effective. As such, NRG's proposed cost of service RMR Rate Schedule is not just and reasonable.

C. NRG's filing lacks provisions to ensure that NRG does not over-recover or double recover costs during the IR4 RMR Term.

As discussed above, not only is the Period II test period not representative of the fixed costs expected for the IR4 RMR Term, but the Monthly Fixed-Cost Charge Rate component lacks an annual true-up mechanism to ensure there is no over-recovery of the fixed costs associated with the IR4 RMR service. Also, because NRG has not explained its methods of tracking and accounting for the costs of the RMR service, there is not adequate transparency for interested parties to challenge the RMR costs included in each of the three Rate components of the RMR Rate Schedule during the IR4 RMR Term.

NRG may unfairly realize a windfall under its proposed RMR Rate Schedule as NRG may use IR4 to provide electric services other than RMR service.[45] To the extent IR4 provides any other electric services, the resulting revenues should be used as revenue

[44] Exh. NPM-003, Statement 2, p. 1 of 3, Line 2.

[45] See, RMR Rate Schedule, section 4.1, Obligation to Offer Unit 4 Into Markets.

credits in the computation of NRG's RMR rate. To do otherwise and ignore the revenues from the other electric services will create a windfall for NRG by enabling NRG to over-recover the costs of providing the IR4 RMR service, as some of these costs will be recovered through billing for other services.

The source of and support for the O&M Expense and Corporate A&G Expense inputs included in the Monthly Fixed-Cost Charge[46], as well as the variable O&M costs recovered in the reimbursement mechanism for fuel and variable O&M costs, are not in the NRG Filing. It cannot, therefore, be determined whether these costs are accounted for on a basis consistent with the Commission's USofA. Without cost support showing how and why these costs are allocated to NRG, the Commission cannot know whether the allocations are just and reasonable.

The adequacy of the refund and crediting mechanisms for the Monthly Project Investment Cost Tracker are not sufficiently definitive so as to ensure there is no over-recovery of RMR Rate Schedule Costs and there are appropriate refund calculations in the event that IR4 continues to operate beyond the IR4 RMR Term.

D. NRG's proposed monthly fixed-cost charge has multiple deficiencies and should be subject to a true-up mechanism.

The proposed Monthly Fixed-Cost Charge requirement of $69,939,754 or $5,828,312 per month was calculated using a cost-of-service analysis for IR4 that includes fixed operation and maintenance ("O&M") expense, corporate administrative and general ("A&G") expense, depreciation, taxes, and return on rate base. The proposed

[46] Exh. NPM-003, Statement 1, p. 1 of 1, Lines 1-2.

test-year fixed costs began with what NRG asserted were the actual costs during the twelve-month period ended December 31, 2021 ("Period I"). NRG's proposal to use a one-year historic test period may be unjust and unreasonable without further information on a larger subset of historic cost data. NRG claims that those actual costs in Period I were adjusted for "known and measurable changes" in costs to provide a projection for calendar year 2022 ("Period II"). NRG asserted the Period II costs are representative of the costs expected to be incurred when service *begins* under the RMR rate schedule.[47] However, NRG proposes to bill this fixed charge for the entirety of the IR4 RMR Term of 4 years and 7 months based on a Period II test period that includes very few adjustments and fails to consider other known adjustments that will occur during the IR4 RMR Term.

The 2021 Period I monthly Normal Maintenance expense is shown to vary by over 90% month to month (*e.g.*, $429,551 in June 2021 and $829,945 in December 2021) [48]. Also, total O&M expense[49] is shown to vary by approximately 83% from month to month (*e.g.*, $1,440,855 in June 2021 and $2,645,793 in September 2021).

Publicly available production cost data and operational statistics for IR4 raise significant questions about the justness and reasonableness of the cost inputs in NRG's fixed cost charge, cost of service study.[50] This data indicates that, historically, IR4's

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[47] Lovinger Exh. NPM-001 at 11:6-7.

[48] Lovinger Exh. No. NPM-003, Statement 4, p. 2 of 3, Line No. 2).

[49] Lovinger Exh. No. NPM-003, Statement 4, p. 2 of 3, Line No. 10.

[50] Calculated by S&P Global Market Intelligence (accessed on April 18, 2022).

operating costs have been significantly lower than the costs included in the purported cost-of-service study submitted with the NRG Filing. For example, for calendar years 2014 to 2020, the total annual fixed O&M costs range from a low of $10,282,614 in 2014 to a high of $11,417,687 in 2019.[51] In contrast, NRG's cost-of-service study lists fixed O&M for Period I (calendar year 2021) as $28,028,649 and for Period II (calendar year 2022) as $27,682,902[52], amounts which are more than twice the annual fixed O&M costs for IR4 incurred in any of the preceding seven calendar years. The NRG Filing failed to explain and justify why the Period I and Period II fixed O&M cost inputs are substantially higher than its actual fixed O&M costs in the prior seven calendar years. This type of discrepancy in costs reinforces the need to have audited financial statements and supporting schedules submitted as part of the cost-of-service filing and the opportunity to investigate further NRG's cost inputs.

Using one distinct test-year with limited adjustments for known changes and fixing that revenue requirement for the 4 years and 7 months IR4 RMR Term will result in an under- or over-recovery of IR4's annual fixed costs. For example, over the IR4 RMR Term, it is likely that on an actual basis the Return component of the Monthly Fixed-Cost Charge will decrease as the rate base offsets for accumulated deferred income taxes and the accumulated provision for depreciation and amortization continue to increase. Also, the amount of regulatory commission expenses is not known and is simply an estimate.

[51] Calculated by S&P Global Market Intelligence (accessed on April 18, 2022).

[52] Exh. NPM-003, Statement 1, p. 1 of 1, Line 3.

Customers need an opportunity to conduct discovery to determine if the test year chosen is representative of the annual costs for the entire term of the RMR agreement and whether fixing that charge, rather using a formula rate with a true-up mechanism and protocols for annual fixed costs is just and reasonable. Fixing a charge at $5,828,312 per month provides an incentive for NRG to spend less dollars on fixed costs so the Monthly Fixed-Cost Charge revenues collected will exceed its actual fixed costs. Moreover, use of a Fixed-Cost Charge provides an incentive to redesignate fixed costs as a cost recoverable through either of the other two RMR rate charges, the Monthly Project Investment Tracker Rate or the variable O&M cost recovery mechanism. NRG has proposed a true-up mechanism for the Monthly Project Investment Tracker, and a mechanism to recover actual fuel and variable O&M costs but no true-up of the costs recovered via the Monthly Fixed-Cost Charge. NRG proposed flat and unchanging Fixed-Cost charge to be set for 4 years and 7 months, the IR4 RMR Term. Such a proposal needs to be fully vetted by interested parties to determine if NRG's Monthly Fixed-Cost Charge Rate is just and reasonable and what cost true-up mechanism should be adopted to prevent any over and double recovery of costs related to the RMR service. Alternately, to ensure that NRG will not over recover its fixed costs, the Commission should require NRG to modify its proposed monthly fixed charge to a formula rate with a true-up mechanism, require an annual informational filing conforming to appropriate formula rate protocols to allow for full verification of the cost inputs.

Furthermore, there is no support in the filing that shows whether the "fixed" costs compiled by NRG during the test year follow the Commission's "predominance" method for classifying fixed production costs. NRG does not use the Commission's USofA accounts and MPC is unable to determine if NRG has properly classified fixed costs from USofA accounts that would normally be deemed "fixed" under the predominance method. MPC is unable to determine the nature of such costs, whether those costs are properly classified as fixed costs, or whether some of the costs would normally be classified as variable costs. Additionally, there is no support for whether the 2021 Period I test year is representative of ongoing costs during the pendency of the RMR agreement. MPC will need discovery to determine if historical costs incurred at the plant are in-line with 2021 costs and whether 2021 costs are properly classified between fixed and variable costs. There is no attempt by NRG or its witnesses to present cost data in USofA accounts for customers and the Commission to review and analyze.

E. NRG's Accounting Bases for its Filing are Subject to Multiple, Severe Deficiencies.

1. Rate Base (NPM-003, Statement 2): Period II Net Plant balance is not adequately supported. (NPM-003, Statement 2, p. 1, Line 1, Column (c).)

NRG chose its own unique method to determine the gross-cost basis of plant in-service and related accumulated provision for depreciation and amortization. NRG does not maintain its books and records in accordance with the USofA[53] and as such, its Total Plant in Service and Accumulated Depreciation and Amortization inputs to its Cost-of-

[53] Lovinger testimony page 16 of 43, line 17.

Service Study are not sourced from NRG's books, records, or audited financial statements.

NRG explains that the Indian River Generating Station was acquired by NRG from DPL in 2001 as part of a transactions that also included the Vienna Power facility, partial interests in two additional generating facilities, and a parcel of land. Subsequently, NRG filed for Chapter 11 bankruptcy protection and emerged pursuant to a plan of reorganization in December 2003.[54] To account for the forgiveness in bankruptcy, Indian River was subject to "Fresh Start" accounting whereby its prior accounting records were replaced with a new asset depreciable cost base by subtracting the gain from debt forgiveness from the previous pre-bankruptcy cost basis. As a result of Fresh Start, NRG explains that Indian River's book costs were reduced and accumulated depreciation was set to zero as of December 2003.[55]

In light of the 2001 acquisition and the 2003 Chapter 11 reorganization, NRG explained it evaluated three sets of costs to determine rate base included in the Monthly Fixed-Cost Rate Charge rate: (1) acquired DPL plant; (2) post-acquisition Indian River cost basis of the acquired DPL plant and new investment prior to emergence from bankruptcy; and (3) fresh start cost basis for plant included in item (2) and new plant investment post-bankruptcy. Ultimately, in its Cost-of-Service Study for the Monthly Fixed-Cost Rate Charge, NRG elected to not use any of these cost methods for plant

[54] Filing at 11.
[55] Filing at 10-11.

investment and instead chose to limit the cost of plant in-service to the post-Bankruptcy costs for new investment installed since its emergence from bankruptcy in December 2003. The new investment consisted of about $381 million to meet emission standards (Environmental Investment) and other investments of about $26 million.[56] NRG chose to use the new gross investment cost basis even though there were several impairments reflected on Indian River's generally accepted accounting principles books subsequent to the installation of the Environmental Investment.[57] That is, NRG chose to ignore the previous impairment write-offs of the new investment when computing the Total Plant in Service input to the Cost-of-Service Study. NRG explained that the GAAP impairments arose from competitive wholesale market conditions adversely impacting the carrying value of the long-lived assets.[58] Applying the effect of the $459 million GAAP impairment loss that NRG recognized on the Indian River Generating Facility in the fourth quarter of 2013[59], and removing the return and income taxes of the net plant investment ("return on") as well as the depreciation expenses ("return of") of net utility plant would reduce the Period II revenue requirement by approximately $39,641,337.

NRG has failed to provide any specific details about the amounts of the impairment write-offs and when they were taken for GAAP accounting purposes, how the GAAP impairment losses were computed, the income tax consequences of the impairment losses

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[56] NPM-001 at 16: 5-14.

[57] *Id.* at 16:16-19.

[58] Exh. NPM-001 at 16:16-19.

[59] NRG Energy, Inc., 2013 From 10K, p. 147. See note 13.

and specifically whether any impairment losses were deducted on federal and state income tax returns, and how the impairment losses were restored with regard to the RMR cost of service study included as Exh. NMP-003 of the filing. As a result, MPC is unable to determine the appropriate cost basis for IR4 utility plant investment and any associated tax effects that may have an impact on the proposed RMR Rate Schedule. MPC and other interested parties need to be afforded the opportunity to investigate further the issue of impairment losses taken by NRG with respect to IR4 and their impact on NRG's cost of service study.

NRG explained it separately computed the balance of Accumulated Depreciation and Amortization by applying depreciation rates from when the investment was first placed in service. IR4 has been in service for 42-years. NRG has neither identified nor supported that the depreciation rates it used to compute this input for the Cost-of-Service Study were just and reasonable.

In addition to the net plant in service issues identified above, because NRG does not maintain its books in accordance with FERC USofA, it is unclear whether NRG has appropriately developed the RMR plant balances based upon an acceptable method in align with industry standards. Without additional information, supporting documentation and audited financial statements, the Total Plant in Service balance is not supported.

Further issues arise related to transmission assets that are included for IR4 gross plant investment[60] in Lovinger's exhibits showing "transmission assets" included in the

[60] Exhibit NPM-003, Statement 2 at 2.

IR4 investment. NRG fails to provide support as to why these transmission assets should be included in the RMR rate and how they relate to the IR4. Until NRG provides supporting documentation and justification as to why these assets should be included, NRG's filing should be considered deficient and disallowed.

2. Period II Accumulated Depreciation and Amortization is not adequately supported. (NPM-003, Statement 2, p. 1, Line 2, Column (c).)

NRG adjusted this balance and "restored" previously booked impairment write-offs. But the filing is unclear as to the amount of the impairments, when they were originally booked, and whether it was appropriate to restore the impairment write-offs.

The balance of accumulated depreciation is based on NRG's use of the original depreciation rates for IR4. The specific rates are not identified in the NRG Filing and it's not clear why it is appropriate to use the original IR4 depreciation rates to compute the accumulated depreciation balance when the unit is now 42 years old. (IR4 was acquired by NRG in 2001 when the unit was approximately 21 years old.) Typically, depreciation rates are updated periodically during the service life of an asset. Based on NRG's filing it appears to be utilizing an effective 4% depreciation rate which equates to an approximate 25-year remaining life.

Period II does not include any adjustment for additional depreciation and amortization provisions booked during Period II.

3. Accumulated Deferred Income Taxes (NPM-003, Statement 2, p. 4 of 4, Line 8)

The ADIT calculation for basis differences between net book basis and net tax basis of plant is inadequate as NRG has only provided inputs for each of these amounts without supporting records that identify the tax basis of and the accumulated depreciation applicable to the actual tax basis of the assets. NRG developed the net tax and net book basis inputs through use of a series of assumptions and allocations. Neither the tax or book basis are derived directly from company books, records, or audited financial statements.[61]

For income tax purposes, NRG improperly used the book basis of utility plant of the post-2003 utility plant additions as the starting balance for the gross tax basis of utility plant.[62] Then to arrive at the net tax basis of utility plant, NRG assumed that 58.2% of the tax basis of the utility plant had been depreciated for tax purposes because Indian River had been depreciated, for income tax purposes, 58.2% of the tax basis of *all its tax utility plant investment*.[63] NRG's method for deriving the net tax basis of the post-2003 additions is significantly flawed for at least two fundamental reasons.

First, NRG's assumption that the starting gross book and tax utility plant balances are the same is unsupported. Accounting standards used to account for utility plant investment recorded on a utility's books differ from the Internal Revenue Code's requirements for utility plant costs eligible for capitalization for income tax purposes. Those differences are referred to as "book-tax basis differences" and result in ADIT

[61] *Id.* at 4: 1-8.

[62] Exhibit No. NPM-001 at 24:3-4.

[63] *Id.* at 24:12-16.

equivalent to the effective tax rate times the amount of the book-tax basis differences. NRG's methodology improperly ignores the income tax effects of book-tax differences resulting from the construction of plant additions and prevents RMR customers from receiving the benefits of the cost-free capital resulting from these book-tax differences in the RMR fixed-cost rate charge.

Second, NRG's use of the 58.2% allocator to assign accumulated tax depreciation to the gross tax balance of utility plant is illogical and unsupported. This method assumes that, *on average*, *all tax utility plant investment is depreciated at the same relative percentage level over time*. That assumption is not reasonable as depreciation for income tax purposes is computed using accelerated tax depreciation methods where larger percentages of depreciation are deductible for income tax purposes in the early years of a utility plant asset's service life with smaller percentages of depreciation claimed in the later years of a utility plant asset's service life. Under tax depreciation methods, older assets will have disproportionately higher percentages of accumulated depreciation balances in comparison to utility plant assets that are early in their service lives. The net tax basis of utility plant needs to be derived from books and records that identify the actual gross tax basis of utility plant and the actual tax depreciation deductions claimed on tax returns that were computed on the actual gross tax basis of the utility plant investment.

Also, NRG failed to make a Period II adjustment for additional ADIT that will result from additional book and tax depreciation basis differences occurring during Period II. Additionally, after the end of Period II and for the remainder of the IR4 RMR

Term, there will be additional book-tax basis differences which will result in changes to the ADIT balance. As explained earlier, NRG's net book basis of the post-2003 net utility plant balance is similarly unsupported as it is not derived from NRG's books, records, and financial statements and requires additional analysis and supporting documentation.

NRG's lack of detail means MPC is unable to determine whether there are other ADIT balances that should be deducted for other types of book-tax differences, such as the costs of employee pension and other post-retirement benefit costs and accruals for damages and losses. As discussed previously, NRG's filing also fails to address the Excess ADIT resulting from the 2017 TCJA used as a rate base deduction. It is unclear whether NRG received a windfall associated with any Excess ADIT that should be returned to customers.

NRG has failed to provide details regarding the 2003 bankruptcy; therefore, it is unclear whether the beginning utility plant balances and accumulated provision for depreciation being proposed are just and reasonable and consistent with the Commission's USofA. In addition, it is unclear whether there are potential deferred income tax benefits resulting from bankruptcy that are being ignored with NRG's proposed utility plant balances.

NRG's treatment of the impairment losses does not provide the accounting details around the impairment write-offs; therefore, MPC is unable to determine the appropriate cost basis for IR4 and any associated tax effects that may have an impact on the proposed RMR rate.

F. NRG's Proposed RMR cost of service Fails to Provide Assurances that All Unfunded Reserves Accounts Shall be Included as an Offset to Rate Base

NRG improperly does not adjust its rate base by offsets for Unfunded Reserves in the proposed Period II 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 NRG, which have not been set up in an established escrow account.

NRG 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:

1. 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.
2. Amounts charged to FERC Account 925 to meet the probable liability for injuries and damages, such as workers' compensation.

3. Amounts charged for FERC Account 926 for Accrued PBOPs and other Employee Benefits.
4. 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.

NRG 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.[64]

G. NRG has failed to support its overall requested rate of return and capital structure.

NRG requests an after-tax Rate of Return of 7.46%[65] that is comprised of (1) capital structure of 52.63% equity and 47.37% debt, which is based on NRG Energy, Inc.'s ("NRG Energy's") (IR4's project level business entity's ultimate parent company)[66]; (2) a cost of debt of 4.36%, which is based on NRG Energy's cost of debt rate[67]; and (3) return on equity ("ROE") of 10.0%, which is the ROE used by DPL in its transmission formula rate.[68] However, NRG's request lacks sufficient support as to the

[64] *See, e.g., Xcel Energy Sw. Transmission Co., LLC*, 149 FERC ¶ 61,182 at P 97 (2014) ("we 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 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.").

[65] *See* Exhibit No. NPM-003, Statement 3, page 1 of 2.

[66] Exhibit No. NPM-001, at 26:3-4.

[67] *See id.*, at 27:20-21.

[68] *Id.* at 28:8-13.

source and validity of the data inputs, is methodologically unsound, and falls afoul of Commission precedent. These failings are discussed below.

NRG does not provide source documents or specific citations in support of the specific components of NRG Energy's capital structure. NRG's witness Mr. Lovinger simply states that NRG Energy's capital structure is 52.63% equity and 47.37% debt[69] and provides an exhibit that purports to provide debt and equity amounts as of December 31, 2021.[70] While Mr. Lovinger provided a list of debt obligations with a total principal amount that matches debt used in computation of its capital structure,[71] no information is provided whatsoever regarding how the equity amount used in the capital structure was determined. Moreover, it is apparent that NRG may have been improperly selective in its utilization of components of NRG Energy's stockholder equity, as reported on its balance sheet and as utilized and reported as common equity for purposes of the NRG Filing. In its Form 10-K filed with the SEC, NRG Energy reports as of December 31, 2021, a total stockholders' equity amount of $3,600 million. This is substantially less than the common equity amount of $8,999 million reported by Mr. Lovinger. The difference in the reported values is apparently driven by Mr. Lovinger's exclusion of a Treasury Stock (i.e., reacquired capital stock) of a negative $5,273 million and accumulated other

[69] Exhibit No. NPM-003, at 26:3-4.

[70] Exhibit No. NPM-003, Statement 3, at 1.

[71] See Exhibit No. NPM-003, Statement 3, at 1-2.

comprehensive income ("AOCI") loss of $126 million.[72] Neither Mr. Lovinger nor NRG explains the basis for the exclusion of the Treasury Stock balance sheet items. This is not an immaterial matter. Indeed, if one were to use the total stockholders' equity amount of $3,726 million (per the Form 10-K balance sheet excluding the effect of AOCI) together with the debt amount of $8,099 million reported by Mr. Lovinger, the equity ratio would be approximately 32% which is considerably lower than Mr. Lovinger's stated equity ratio of 52.63%. A revision of the equity ratio to this lower amount would result in a reduction of the Period II revenue requirement of $5,079,059. This is clearly a matter that needs to be investigated further and MPC requires discovery to determine whether the data inputs used in the capital structure conform with the Commission's USofA requirements and ratemaking principles together with Commission precedent. Additionally, discovery is required to verify the cost of debt inputs stated in Mr. Lovinger's exhibit supporting the cost of debt of 4.683%.[73]

Furthermore, it is apparent that the cost of debt rate computed by witness Mr. Lovinger does not conform with the Commission's requirement that the cost of debt be based only on costs associated with long-term debt obligations,[74] by including costs associated with several letter of credit facilities and receivables securitization.[75] MPC

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[72] Note that the Commission excludes other comprehensive income from the common equity input for the computation of capital structure.

[73] Exhibit No. NPM-003, Statement 3, at 2.

[74] *See, e.g., Opinion No. 572*, 173 FERC ¶ 61,045, at P 45 ("we agree with PG&E and Trial Staff and find that the use of net proceeds to calculate the long-term debt cost rate is appropriate.")

[75] See Exhibit No. NPM-003, Statement 3, at 2, lines 12-17.

preliminarily estimates the removal of these inappropriate line items reduces the cost of debt from 4.63% to 4.09%,[76] or a $669,677 reduction to the as filed Period II revenue requirement.

In addition to the issues identified above, the use of NRG Energy as proxy for both the capital structure and cost of debt of Indian Rivers is simply inappropriate because NRG has below investment grade long-term credit ratings. In particular, it has an S&P Issuer Credit Rating of BB+ and a Moody's Long-Term Rating of Ba1. As a result of NRG Energy's below investment grade credit rating, it is inapposite to assume that NRG Energy's capital structure and cost of debt is representative of the inherent risk and cost basis for IR4 under the regulated cost-of-service agreement which will allow IR4 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 parent's capital structure was anomalous and not representative of the subject utility's risk profile.[77] As a result of the unsuitability of the using NRG Energy as a proxy, an evidentiary hearing is required to

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[76] Removing the annual cost of debt for the items listed in lines12-17 of Exhibit No. NPM-003, Statement 3, at 2, reduces the total annual cost of debt from $367,731,837 to $367,731,836. Also, the Net Proceeds total is reduced from $7,937,372,794 to $7,957,226,943 when these items are removed. When this newly adjusted annual cost of debt is divided by the newly adjusted net proceeds amount the cost of debt rate is 4.09%.

[77] *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).

determine an appropriate hypothetical capital structure and cost of debt for use in IR4's RMR Rate Schedule.

Regarding NRG witness Mr. Lovinger's recommendation to use the ROE of the transmission owner with which the generation facility is interconnected (*i.e.*, DPL's 10.0% base ROE), it is important to highlight that Mr. Lovinger relies on Commission precedent, namely *Bluegrass Generation,*[78] to support his recommendation in a selective and inappropriate manner. Mr. Lovinger posits that "the Commission commonly permits use of a proxy to establish a reasonable return on equity based on that of the transmission owner with which the merchant generator is interconnected as reflected in *Bluegrass Generation*." However, in that decision, which related to a reactive power proceeding, the Commission determined it was just and reasonable to use the overall rate of return of the transmission owner, inclusive of interconnected utility's ROE.[79] In other words, the Commission did not exclusively rely on ROE in singular manner but rather it relied on the overall rate of return.[80] Additionally, in prior decisions which the Commission referred to in *Bluegrass Generation*, it is evident that the Commission expressed the view that the overall rate of return can be used in the context of specific circumstances

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[78] *Bluegrass Generation Co., L.L.C.*, 118 FERC ¶ 61,214 at P 86 (2007).

[79] *Bluegrass Generation* at P 86.

[80] A further distinction regarding the applicability of the *Bluegrass Generation* precedent to the set of circumstances at issue in this filing bears noting. In *Bluegrass Generation*, the Commission addressed the risk of a merchant generator; however, the Commission has recently recognized in a separate must-run reliability cost-of-service proceeding that the risk associated with such a cost recovery agreement differed fundamentally to that of a merchant generator. *See Mystic Power, LLC* 176 FERC ¶ 61,019 at P26. ("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.").

pertaining to reactive power rate proceedings. Moreover, in a recent reactive power decision, the Commission relied on the overall rate of return of the transmission owner to which the generation facility was interconnected with,[81] and described that in reactive power rate proceedings it has "generally allowed merchant generators to use the Commission-authorized *cost of capital* of the interconnected utility as a proxy."[82] Therefore, it is clear that by not recommending the use of the overall rate of return of DPL, that Mr. Lovinger fails to conform with the precedent he relies on. Indeed, the use of DPL's overall rate of return could be one approach to address the flaws of NRG PMLLC proposal to use NRG's capital structure and cost of debt as a proxy for Indian Rivers. The Commission needs to set the filing hearing in order for MPC and other intervenors to determine what the appropriate ROE and overall rate of return is for the IR4 RMR Rate Schedule.

H. NRG's Filing fails to support its Total Overall Cost-of-Service (NPM-003, Statement 1, p. 1 of 1).

1. O&M expense (NPM-003, Statement 1, p. 1 of 1, Line 1)

Overhead – It is unclear whether the cost estimates of O&M include overhead (*e.g.*, administrative support, etc.). To the extent that NRG includes overhead type costs

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[81] *Panda Stonewall, LLC*, 174 FERC ¶ 61,266, at P 202.

[82] *Id.* at P 177 (emphasis added).

in O&M, NRG should be required to provide information as to the components included in "overheads."

To the extent that NRG is allocating costs to IR4, NRG should be required to provide any calculations for indirect charges and the methods utilized (*i.e.*, Massachusetts method), including a copy of any cost allocation manual etc.

Fixed O&M – Without further supporting documentation for the components included in the fixed charge O&M amount, MPC is unable to determine whether this proposed amount is just and reasonable. The NRG witness provided no comparison of Period I costs, which are the foundation of his Period II projections, with historical costs to show whether Period I is a reasonable estimate of on-going fixed costs. Coupled with no true-up of fixed costs, this area is ripe for over- or under-recovery of fixed costs during the term of the agreement. NRG should be required to implement a true-up mechanism and file an informational filing annually in order provide the customers the opportunity for investigation of the costs. As part of this review, NRG should provide customers with review procedures and challenge rights in the event that customers disagree with NRG's monthly fixed charge costs.

2. Corporate A&G expense (NPM-003, Statement 1, p. 1 of 1, Line 2).

It is unclear whether this amount is reasonable. NRG has provided an allocation of NRG corporate A&G costs allocated to IR4. MPC will need discovery to determine if this allocation of costs is reasonable and representative of the costs that should be assigned to the plant during the RMR agreement.

3. Depreciation expense (NPM-003, Statement 1, p. 1 of 1, Line 4).

NRG has failed to provide support for its annual depreciation expense included in its cost-of-service study. NRG's depreciation calculation is derived by "Property Group," not by FERC primary plant account. NRG explained the proposed depreciation expense was developed using the physical lives of the facilities determined on their in-service date or an effective depreciation rate of 4% (*i.e.*, 25-year remaining life).[83] Neither the depreciation rates and related cost of removal and salvage rates nor the original physical lives used to compute the depreciation expense input were identified or documented in any way. NRG has failed to provide any evidence that FERC approved those depreciation rates or whether the depreciation rates should have been revised when the accumulated depreciation for utility plant was zeroed-out as a result of the bankruptcy proceeding, or when impairment losses were booked, or because of other factors affecting the economic service life of IR4.

Standard industry practice is that depreciation rates are routinely reviewed every three to five years to ensure rates are reasonable in light of current circumstances. Since NRG's emergence from bankruptcy in December 2003, pollution control investment was added to IR4 in 2008 to 2012, making up the majority of current original cost plant investment included in NRG's cost-of-service study ("post-2003 plant investment"). NRG should be required to provide depreciation rates by primary plant account including rates for salvage and cost of removal as NRG does not have a

[83] NPM-001 at 41:5-8.

FERC-approved composite depreciation rate.[84] MPC is unable to determine whether the book net plant investment should have been depreciated differently, certain book utility plant accounts are fully depreciated when estimated salvage and cost of removal is factored, and whether there is actually any book net utility plant investment remaining to be depreciated during the RMR period.[85]

4. Taxes other than income taxes (NPM-003, Statement 1, p. 1 of 1, Line 5).

NRG has inappropriately included gross receipts taxes in the fixed cost charge cost of service. Gross receipts taxes are an incremental tax on gross revenues/receipts and not on income for business activity within the State of Delaware. At the federal level NRG is afforded an income expense deduction on these gross receipts taxes. However, for purposes of computing income taxes this is not a component that is included for ratemaking purposes as it is a flow-through item (i.e., charged separately to customers within the State of Delaware and then paid to the Delaware Division of Revenue).

5. State and federal income taxes (NPM-003, Statement 1, p. 1 of 1, Line 6).

NRG has provided no documentation of the calculation of the ITA. Furthermore, NRG states that the project-level ownership entity is a pass-through entity[86] and is not

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[84] See NPM-001 at 41: 20-22.

[86] *See* Exhibit NPM-001 at 22: 1-11.

required to pay income taxes; based on this statement, NRG should not receive an ITA or have ADIT on its books. Also, NRG has failed to address excess ADIT resulting from the TCJA in its filing, but it appears that there should be an adjustment to the ITA to incorporate excess ADIT amortization offset from the TCJA in the federal income tax expense calculation.

I. Project investment recovery and the tracker mechanism for its recovery suffers from multiple infirmities.

1. Background

Each month during the term of the RMR Rate Schedule, PJM is required to pay NRG a monthly payment to reimburse the costs of project investment or "PI." Project Investment is "an investment made to enable Unit 4 to continue operating for the period during which PJM has identified a reliability need. Project investment may include repairs, replacements, additions, actions for NERC or other regulatory compliance, and maintenance of IR4 facilities and equipment and associated parts, supplies, labor (including overtime if consistent with Good Utility Practice), and overheads."[87] Pursuant to the RMR Rate Schedule, the Monthly Project Investment Tracker is be calculated as:

Monthly Project Investment = Actual PI Costs accrued Tracker Payment
(with carrying charges)

"Actual PI Costs" are the actual project investment costs accrued in the calendar month regardless of the project calendar year to which the project investment is

[87] RMR Rate Schedule, Section 1.17.

assigned.[88] The RMR Rate Schedule provides that carrying charges will be accrued on Actual PI costs at a rate of 9.49 % per annum from the first month in which the cost is accrued until paid.[89]

Under the Monthly Project Investment Tracker Payment Rate proposal, NRG may recover project investment cost which have been accrued but are unpaid.

2. The use of cost accruals and the carrying charge rate used for unrecovered project investment costs are unjust and unreasonable.

The cost recovery procedures established for the Monthly Project Investment Tracker enables NRG to recover costs subject to the tracker on an accrual basis, to which is applied a carrying charge. Under this methodology, NRG may accrue and recover project costs prior to any cash outlays, thereby creating the potential for a windfall to NRG ("pre-collection of project costs"). The Commission has a long-standing policy of not allowing the accrual and recovery of carrying charges when there has not been any cash outlays of costs, and it has required unpaid accruals to be deducted in computing the carrying charge base.[90] In that event, the Monthly Project Cost Investment Cost Tracker allows a pre-collection of project costs and/or the accrual and recovery of carrying charges on project costs that are accrued but unpaid will cause an unjust and unreasonable result. NRG should be required to revise the Monthly Project Investment

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[88] RMR Rate Schedule, Section 5.2.F.

[89] RMR Rate Schedule, Section 5.2.G.

[90] *Opinion No. 298, United Gas Pipe Line Company,* 42 FERC ¶ 61,353 (1988) ("the Commission intended to allow carrying charges only for costs paid or authorized for payment …").

Tracker recovery mechanism to prevent it from pre-collecting project costs and accruing and recovering carrying charges on projects costs where there have been no cash outlays. It appears from the provision that only PJM and IMM can participate in such review. It is unjust and unreasonable to not allow all customers paying the rate to have 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.[91]

In addition, NRG proposes to use a 9.49% carrying charge rate, which is the same as NRG's proposed overall pre-tax weighted rate of return, to accrue carrying charges on accrued but unrecovered project investment costs. NRGF's carrying charge proposal results in an overstatement of carrying charges. NRG should be utilizing the FERC interest rate or another short-term interest rate in this calculation for short-term borrowings available NRG. Moreover, as explained above, it is unclear whether NRG is accruing carrying charges on cost accruals rather than on cash outlays. NRG should only be permitted to recover a carrying charge for cash outlays as NRG should not earn a return on amounts that have not expended by NRG.

NRG has failed to provide examples showing the application of the carrying charge and the Monthly Project Investment Cost tracker. Without this information, MPC is unable to verify whether NRG's proposed mechanism is just and reasonable. For

[91] *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).

example, NRG should explain for a particular project investment that would be under construction from January 1 of a calendar year and completed in June, and funds are spent during a six-month construction period: How will the amount that is accrued monthly be derived? And how will carrying charges be applied to such expenditures when the mechanism appears to reimburse NRG for each month of the accruals irrespective of its cash outlays?

Furthermore, NRG's mechanism only addresses cost accruals and 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 NRG's filing deficient.

3. NRG has failed to provide discussion of the tax treatment of project investment costs and the effect on ADIT.

NRG 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 RMR rate, or when they will be reflected on the income tax returns. Without this discussion, MPC is 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.

4. NRG has failed to address the reimbursement for actual costs related to the Project Investment accrued prior to June 1, 2022.

In relation to Project Investment for the 2022 Project Calendar Year, NRG states that it (see RMR Tariff 5.2.F) will be reimbursed pursuant to Article VI for pre-June 1, 2022 costs. Article VI does not provide any provisions for pre-June 1, 2022 project cost accruals nor does it discuss how these costs will be recovered, whether there will be carrying charges, what projects they relate to etc. NRG fails to explain what these costs are, why they were incurred prior to June 1, 2022, and why the recovery of these pre-June 1, 2022 costs is appropriate under the term of the RMR agreement. The lack of specificity in Article VI and justification for the recovery of pre-June 1, 2022 costs make this filing deficient and this cost recovery of pre-June 1, 2022 amounts should not be allowed absent supporting documentation to address these concerns.

5. NRG's filing is unclear whether the list of Project Investment for 2022 through 2026 has been agreed to by PJM and the IMM or whether these projects are necessary.

NRG's filing does not indicate whether the listing of Project Investment for 2022 through 2026 has been agreed to by PJM and the IMM.[92] MPC will need to assess the listed projects through discovery and decide whether they are appropriate investment for a generating unit under a short-term RMR agreement.

6. NRG's filing is unclear whether the refund mechanism for project investment if IR4 remains operational beyond the RMR Term is just and reasonable.

NRG states that "NRG PMLLC shall refund a share of the amount for which it received reimbursement using the formula included in section 5.3." Therefore, it appears there is some refund of project investment if IR4 remains operational beyond the IR4 RMR Term (Tariff 5.3). NRG fails to discuss in enough detail how the formula components of such refund mechanism will be determined. For instance, how is the

[92] Exhibit NPM-005 attached to Pistner testimony.

"Variable X – Project Investment (PI) Cost[93]" amount determined? Will it include the carrying charges as a component of the refund? MPC will require discovery and analyses to determine whether the "refund" formula is just and reasonable. Furthermore, Section 6.4[94] discusses that "…NRG-PML shall provide the schedule of Refund of Project Investment Reimbursement identifying by month and year each month's refund amount PJM shall use to comply with Section 5.3." NRG's proposal is insufficient. NRG should be required to provide supporting workpapers, calculations and documentation to support each component of the refund calculation. In addition, it is unreasonable to require the customers to wait until the end of the RMR Term to review such calculations. NRG should be required to make a filing at FERC if the unit operates beyond December 2026 NRG's RMR Term to evaluate the number of months of project investment enables IR4 to operate beyond the RMR Term and evaluate the prudency of any project investment required for continued operation under the RMR Agreement. Subsequently, NRG should be required to file an Informational Filing yearly in order provide the customers the opportunity for investigation of the costs. As part of this review, NRG should provide customers with review procedures and challenge rights in the event that customers disagree with NRG's calculations.

J. NRG has failed to support the Cost Reimbursement Mechanism to Recover IR4's Variable Operations and Maintenance costs or provide a review process for the mechanism.

[93] RMR Schedule Section 5.3 table.

[94] RMR Schedule.

The filing includes a mechanism to recover "variable" O&M expense during the pendency of the term of the RMR agreement. NRG has proposed a tracker for fuel and variable operations and maintenance costs. NRG does not explain how the costs will be identified and included as part of the tracker. There is no detailed expense account information that would allow MPC or other interested parties to review the types of costs included in this variable O&M reimbursement mechanism, no listing of costs by USofA account for costs included in this 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 NRG is proposing to utilize and whether they are just and reasonable. In addition, NRG has failed to provide examples of how the monthly fuel and variable O&M expense tracker will be implemented in order for MPC or other interested parties to evaluate the justness and reasonableness of the cost reimbursement mechanism. For the foregoing reasons, MPC will need discovery to review this proposal to see if it is reasonable under the proposed RMR Rate Schedule.

IV. The NRG Filing seeks to exploit transmission and power planning Deficiencies that FERC should remedy.

The circumstances of NRG's filing in this proceeding raise serious concerns about the planning process and procedures followed in PJM with respect to RMR arrangements. Unlike in other ISO/RTOs, generators, in PJM, can invoke the process to trigger the grant of a RMR through a request for deactivation, subject to a very short notice period. They then seemingly can shut-down at their discretion even if determined by PJM to be needed for grid reliability. PJM utilizes a compressed reliability review, measured by the 90-day time-line running from the delivery of a notice of deactivation by a generating unit owner, to make this determination. The PJM IMM has proposed and continues to advocate for a more pro-active forward-looking role for PJM in assessing units "at risk" for closure to forestall RMR applications, particularly of units that are not picked up in the forward capacity market but may be necessary to maintain grid reliability and, therefore, eligible for a RMR if grid planning efforts are not started earlier.[95] However, PJM seemingly has not adopted this practice.

A consultant report from more than a decade ago pointed out and described the infirmities of PJM's RMR process as follows:

> As EPA and the states work to improve public health by reducing coal-fired power plant pollution through a series of legally mandated rulemakings, operators of some plants are likely to opt to shut down some coal capacity and replace it with cleaner resources. PJM estimates that between 14,000 and 17,000 MW of smaller, older coal power plants lack pollution controls which EPA may require. A substantial number of these plants, and perhaps others, may retire. *Yet, PJM's tariff now requires generators to give PJM only 90 days' notice before they retire—and PJM is supposed to respond with a reliability analysis in just 30 days. This notice period is unacceptably short, especially in this period of major potential retirements, and will lead to expensive must-run agreements while PJM scrambles to conduct reliability analyses.* Generators make retirement decisions more than 90 days in advance, and PJM, as well as ratepayers in its region, deserves to know these decisions in advance to allow for cost-effective retirement planning. We recommend that PJM extend its required notice period to at least three years—the same timeframe used for capacity market auctions—to provide adequate lead time to design and implement any necessary reliability upgrades. To supplement this enhanced notification period, PJM might also consider developing incentives

[95] PJM IMM, *State of the Market Report (2021)*, vol. 1, at 42, vol. 2, at 323 (2022).

> for companies to provide earlier notice, or disincentives (such as less favorable must-run agreement terms) for companies that provide only short notice. As well as enhancing its notice requirements, PJM should work to enhance its internal, independent modeling capacity to develop screens for plants that are clearly at risk and likely to retire. Ample publicly available data can be used to identify older, less-efficient plants, and those without necessary pollution controls. Indeed, PJM's own capacity auction can be used to identify plants that repeatedly fail to sell their capacity. Although generators may have some legitimate concerns with PJM's own retirement screenings, these concerns must be counter-balanced by the strong ratepayer interest in avoiding costly must-run agreements and rushed reliability projects. Whether through improved notice requirements, improved screening analyses, or some combination, PJM must be able to plan for retirements with lead-times far greater than the 90 days now granted in its tariff.[96]

These infirmities continue to the present and are evident in the NRG RMR filing initiating this proceeding. The NRG RMR filing is an extremely adverse result for DPL Zone electric customers, entailing costs that—over four years and seven months if the full term of the RMR is utilized—could exceed $400 million. This contrasts with the solution obviating the need for the RMR, in the first place, entailing an approximate $40 million transmission fix (or perhaps other lower cost alternatives) if a more pro-active planning approach had been adopted, but now can only occur after the RMR agreement takes effect because the line's planning, permitting and construction will only occur sequentially after the RMR agreement becomes effective and is performed over its term.

[96] Synapse Energy Economics, Inc., *PJM System Planning, Enhancements for the 21st Century* (2011), p. 9. *See also*, *id.* at pp. 43-44 (and Appendix A) for discussion of recommended enhancements to PJM's planning processes in order to properly plan for, anticipate and pro-actively implement measures to forestall RMR arrangements. The Synapse report sought to address the then anticipated impending wave of coal plant retirements and the challenge that presented for the PJM grid at the time. Today, more than a decade later, the context is different but MPC submits the observations and recommendations of the report remain valid about the continuing problematic posed by RMRs, particularly in the new context of ambitious decarbonization initiatives.

Moreover, electric customers in the DPL Zone wind up paying partially or potentially for duplicative capacity, once for the generating capacity supplied by the NRG RMR and, again, for the capacity they are responsible for to assure adequate generation under PJM's Reliability Pricing Model ("RPM") capacity market construct (in part, duplicative of the retained IR4 capacity, but diverging due to different metrics for the different procurements). Reflecting a further infirmity in the PJM RMR process, the NRG RMR cost as NRG proposes it, on a per-MW basis, is significantly greater than that afforded capacity procured through the PJM RPM

While the benefit of hindsight may make critical conclusions about PJM's overall planning procedure too facile, one can argue that the warning signs of the adverse, very expensive for ratepayers, irrational result of NRG's RMR filing were apparent before the fact. IR4 failed to clear in the PJM capacity market, IR4's operating time in the PJM energy market was reduced based on relative fuel economics and electric energy demands in 2019/2020 and the Delmarva peninsula has had significant recurring transmission constraints in the past, signaling grid fragility in the event of the exit of a 410 MW generating unit. NRG's RMR filing leverages this circumstance.

The apparent limitations in PJM's planning and practices regarding RMR arrangements stress even more the structure that is in place in PJM applicable to RMRs, particularly the rigor of PJM's reliability planning for "at risk" units, and the policing of and limitations on the quantum of recovery due generators under a RMR arrangement.

CONCLUSION

The NRG Filing is contrary to and mis-states Commission precedent regarding the permissible level of revenue requirements due under a RMR arrangement under the PJM OATT. Even if the filing is evaluated in a traditional manner under the Commission's rules under FPA Section 205 as a cost-of-service tariff filing, it is deficient and would otherwise merit rejection absent the exigent circumstances of the filing where PJM has determined that continued operation of IR4 is needed for grid reliability. MPC is also deeply concerned that the planning procedures and process followed by PJM as evidence in this filing have serious deficiencies. MPC respectfully requests that the Commission grant the relief requested in this Protest.

Respectfully submitted,

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/s/ electronic signature

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Dated: May 6, 2022.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding. This 6th day of May 2022.

/s/ electronic signature

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