STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY	**:**
d/b/a NATIONAL GRID'S ELECTRIC	**:**
INFRASTRUCTURE, SAFETY, AND RELIABILITY	**: DOCKET NO. 5209**
PLAN FY 2023 PROPOSAL	**:**

REPORT AND ORDER

I. National Grid's Filing

On December 20, 2021, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) filed with the Public Utilities Commission (Commission) its proposed Electric Infrastructure, Safety, and Reliability Plan (Electric ISR Plan) for FY 2023.[1] National Grid indicated that the Division of Public Utilities and Carriers (Division) had reviewed the proposed Electric ISR Plan and that it reflected a general consensus between

[1] R.I. Gen. Laws § 39-1-27.7.1 states, in relevant part, that National Grid shall file proposals with the Public Utilities Commission that contain:

> An annual infrastructure, safety and reliability spending plan for each fiscal year and an annual rate reconciliation mechanism that includes a reconcilable allowance for the anticipated capital investments and other spending pursuant to the annual pre-approved budget as developed in accordance with [the following:] Prior to the beginning of each fiscal year, gas and electric distribution companies shall consult with the division of public utilities and carriers regarding its infrastructure, safety, and reliability spending plan for the following fiscal year, addressing the following categories: (1) Capital spending on utility infrastructure; (2) For electric distribution companies, operation and maintenance expenses on vegetation management; (3) For electric distribution companies, operation and maintenance expenses on system inspection, including expenses from expected resulting repairs; and (4) Any other costs relating to maintaining safety and reliability that are mutually agreed upon by the division and the company. The distribution company shall submit a plan to the division and the division shall cooperate in good faith to reach an agreement on a proposed plan for these categories of costs for the prospective fiscal year within sixty (60) days. To the extent that the company and the division mutually agree on a plan, such plan shall be filed with the commission for review and approval within ninety (90) days. If the company and the division cannot agree on a plan, the company shall file a proposed plan with the commission and the commission shall review and, if the investments and spending are found to be reasonably needed to maintain safe and reliable distribution service over the short and long-term, approve the plan within ninety (90) days.

The FY 2023 Electric ISR Plan and all of the documents referenced herein can be found on the Commission's website at: https://ripuc.ri.gov/eventsactions/docket/5209page.html.

National Grid and the Division.[2] The proposed FY 2023 revenue requirement was $49.7 million.[3]

On March 29, 2022, after conducting discovery and a hearing, the Commission approved the FY 2023 Electric ISR Plan. The approved revenue requirement was $49,721,324, resulting in an incremental fiscal year upward rate adjustment of $8,363,605. This will support a FY 2023 Electric ISR Plan capital budget of $104,750,000, a vegetation management budget of $11,875,000, an infrastructure and maintenance (I&M) budget of $1,015,000, and other expense of $249,000.[4]

A. Electric ISR Plan

In support of the Electric ISR Plan, National Grid submitted the direct testimony of National Grid Service Company employees Patricia C. Easterly, Director of Performance and Strategy; Ryan A. Moe, Lead Specialist in Vegetation Strategy; and Caitlin Broderick, Engineering Manager in the Distribution Planning and Asset Management Department (collectively, the plan witnesses). In support of the development of the revenue requirement and to explain the reconciliation process, National Grid Service Company submitted the direct testimony of its employee Melissa A. Little, Director of New England Revenue Requirements. In support of the new tariffs and to explain the calculation of the factors and provide customer bill impacts, National Grid Service Company submitted the direct testimony of its employee Daniel E. Gallagher, Senior Analyst, New England Electric Pricing.

The plan witnesses indicated that the proposed Electric ISR Plan covered four budget categories for the fiscal year ending March 31, 2023: capital spending on infrastructure

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[2] Filing Letter at 1 (Dec. 20, 2021).
[3] Filing Letter at 2.
[4] *Id.;* Easterly, Moe, and Castro Joint Test. at 12 (hereinafter "Joint Test."); Electric ISR Plan at Section 5: Attachment 1, page 1.

projects; O&M for vegetation management; I&M; and Volt/Var Optimization and Conservation Voltage Reduction Expansion (VVO/CVR).[5] They explained that the Electric ISR Plan included a spending plan and proposed an annual reconciliation mechanism to "provide for recovery related to capital investments and other spending undertaken pursuant to the annual pre-approved budget for the Electric ISR Plan."[6]

The proposed capital spending plan for FY 2023 was $104.8 million.[7] According to the plan witnesses, the Electric ISR Plan addressed the capital investment needed for five specific purposes: to meet state and federal regulatory requirements applicable to the electric system (Customer Request/Public Requirement); to repair failed or damaged equipment (Damage Failure); to address load growth/migration; to maintain reliable service (System Capacity and Performance); and to sustain asset viability through targeted investments driven primarily by condition (Asset Condition).[8] Of these, the Company considers Customer Request/Public Requirements and Damage Failure to be non-discretionary "in terms of scope and timing" and "subject to necessary and unavoidable deviations."[9] These items, totaling $41,434,000, account for 39.6% of the proposed capital outlays in FY 2023.[10]

The remaining categories, System Capacity and Performance, Asset Condition, and Non-Infrastructure, are meant to reduce the degradation of the service life of equipment, allow for more flexibility in the system for purposes of meeting various contingencies such as load growth and migration, and address poor condition of aged assets.[11] These items together comprised the other 60.4% of the FY 2023 budget.[12]

[5] Joint Test. at 7.
[6] *Id*.
[7] *Id*.
[8] *Id*. at 10-11.
[9] *Id*. at 13.
[10] *Id*. at 12.
[11] *Id*. at 13.
[12] *Id*. at 12-13.

The Electric ISR Plan also included the proposed FY 2023 spending levels for the Company's Vegetation Management Program of approximately $11.9 million, an increase of approximately $1.1 million from the spending approved in the FY 2022 Electric ISR Plan. The primary reason for the increase is a $700,00 increase in cycle pruning costs. Based on bids received for FY 2023 work, the plan witnesses explained that pruning costs have risen significantly compared to the prior year's costs as a result of a shortage in qualified tree workers. As in the previous year, the spending budget includes $200,000 to target areas of poor performance.[13] In support of the request, the Company noted that based on the previous year's targeted pruning of such areas, there has been a 51% reduction in tree events and a 60% reduction in customers interrupted.[14]

The I&M spending included capital amounts already accounted for above plus $1.0 million for O&M costs related to the I&M program, including inspections, voltage testing, and the contact voltage program. Finally, there were" other" O&M expenses in the amount of $225,000, related to the ongoing long-range system capacity load study and expansion of the VVO/CVR program.[15]

The Company agreed to provide the Commission with quarterly reports on the progress of executing the ISR Plan as well as an annual report at the time the Company files its annual reconciliation. Additionally, the Company and the Division agreed that, if circumstances required, National Grid would be allowed reasonable deviations from the plan, with explanations of any significant deviations to be included in its quarterly and year-end reports.[16] National Grid provided the Commission with a benefit cost analysis based on the

[13] *Id*. at 15-16.
[14] *Id*. at 16.
[15] *Id*. at 17.
[16] *Id*. at 17.

Commission's Docket No. 4600 Guidance Document and Framework to support new budget proposals and certain existing categories that had increased budgets.[17]

B. Development of the ISR Factor

Mr. Gallagher explained that the overall ISR Factor embedded in distribution rates contains two mechanisms: (1) an Infrastructure Investment Mechanism to recover costs associated with incremental capital investment and (2) an O&M Mechanism to recover O&M expenses related to inspection and maintenance and vegetation management activities. To design the Infrastructure Investment Mechanism and develop the incremental capital investment, following Commission review of a cumulative revenue requirement, National Grid applies a rate base allocator that was developed in the most recently approved cost-of-service study. These become the Capital Expenditure Factors included in each rate class's respective overall ISR Factor. Similarly, the O&M mechanism is designed to allocate the inspection and maintenance and vegetation management expenses to rate classes based on the percentage of total distribution O&M expense allocated to each rate class in the most recent cost-of-service study. Within each rate class, National Grid calculates a per unit charge based on kilowatt hour (kWh) usage for non-demand classes and on a kilowatt (kW) basis for demand classes.[18]

Each year, by August 1, the Company proposes Capital Expenditure reconciling factors and an O&M reconciling factor to become effective on October 1 for the following twelve-month period. The reconciliation compares the actual cumulative revenue

[17] *Id.* at Bates 90-94.
[18] Gallagher Test. at Bates 191-95, 196-97; Section 6: Rate Design; For G-02 and G-32/B-32 customers, whose charges include both demand and usage, the Capital Expenditure Factors and O&M Factors are designed "to not significantly change the relationship between the existing charges and will ensure that customers within the class that have differing usage characteristics will not experience significantly different bill impacts." Crary Test. at 195.

requirement to actual billed revenue generated from the Capital Expenditure Factors included in the prior year's overall ISR Factor. Any over- or under-recovery is refunded to or collected from customers through the Capital Expenditure Reconciling Factors. The O&M reconciling factor will compare the actual I&M and vegetation management O&M expense to actual billed revenue generated from the O&M factors. Any over- or under-collection of actual expense is refunded to or collected from customers through a uniform per kWh charge applicable to all rate classes.[19]

II. Division's Filing

On February 18, 2022, the Division submitted the testimony and report of its consultant Gregory L. Booth, P.E. on the Electric ISR Plan and a memorandum from Chief Accountant John Bell, on the revenue requirement. The Division generally supported the FY 2023 Electric ISR Plan and budget. Mr. Booth, however, as in years past, had several recommendations relating to planning and appropriate categorization and tracking of expenses.[20] He indicated that "[s]hould Narragansett transfer to a new owner, Company changes that impact capital investment plans are inevitable and the Division's expects a higher level of scrutiny will be required" to assess whether new proposals are needed and provide quantifiable benefits to ratepayers that outweigh the costs, avoidance of a degradation of service, and avoidance of duplicative or excess costs to ratepayers.[21] Consistent with this statement, Mr. Booth recommended that:

> In the event the PPL acquisition of Narragansett transpires, Narragansett Electric shall provide, within 60 days of closing a comprehensive report addressing, at a minimum: an organization chart identifying the new ISR Plan team members and responsibilities as compared to the current organization, any changes in the project sanctioning process; and proposed changes to the ISR Plan process; and a schedule for the

[19] *Id*. at Bate 195-96.
[20] Booth Test. and Report at 9-13;
[21] Booth Report at 8.

> quarterly presentations of the quarterly reports. The Company shall provide report updates at each quarterly presentation.[22]

In his report, Mr. Booth recognized changes National Grid has made to better classify certain work within the non-discretionary damage/failure category to determine that would more properly fall within a discretionary spend category, explaining that it is too early to determine the effectiveness of the enhancements, but he was satisfied that the Company was closely monitoring work to validate the classifications. He further indicated that the FY 2022 results would determine the need for further refinement.[23]

Addressing the Asset Condition Category, Mr. Booth noted that there are three major projects, including the Southeast Substation, Dyer Street Substation, and Providence Area construction. Specifically addressing Dyer Street, while continuing to support the project, he reiterated issues raised during his review of the FY 2022 Electric ISR Plan regarding scope and budget increases.[24] Mr. Booth explained that Dyer Street is an indoor substation first constructed in 1924 still serving the downtown Providence Area. According to Mr. Booth, "the Company identified multiple operational, condition and safety issues within the station, and ranked it as the highest priority for replacement. The recommended plan includes retiring all equipment, replacing the station, rehabilitating a historically significant structure co-located on the site, and converting/replacing multiple underground circuits. As the project moved through initial engineering, the Company encountered complexities involving the historical building rehabilitation and revised the plan to rebuild the station on land located at the South Street site. Project development was paused in FY 2021 and has since moved into construction."[25]

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[22] Booth Report at 13.
[23] Booth Report at 15.
[24] Booth Report at 18.
[25] *Id*. at 18.

Mr. Booth stated that in his report on the FY 2022 Electric ISR Plan, he had noted that the scope change increased the cost estimate by nearly $8 million, and that Dyer was projected to be a $22 million project. While the current budget estimates are below $22 million, he stated that there is a 50% chance of the project coming in above the approved estimate. His stated primary concern was that the actual costs will substantially exceed the initial estimate, which has customarily occurred with the Company's major projects.[26] He indicated that the Company was working to improve its project estimating process for complex projects and indicated that Dyer Street will be an initial test of the effectiveness of the changes.[27]

The next set of projects Mr. Booth highlighted were those emanating from the Providence Area Study, totaling approximately $8.4 million of the $20.4 million allocated to major projects. Mr. Booth noted that over a twelve-year period, the Company has calculated a high-level estimate of spending over $120 million for the planned Providence Area projects. He explained that this estimate will change and pointed to the almost doubling of expenses for the Admiral Street project between FY 2022 and FY 2023. He stated that "[a]lthough the Company is attempting to improve the accuracy of early estimates, the results are not yet evident." He explained that the practical implication is that the Company will have to lengthen complex project implementation schedules or moderate spending in other discretionary categories to maintain reasonable overall budgets.[28]

Additionally, while supporting the accelerated 3V0[29] deployment within the System Capacity and Performance category for FY 2023, because it provides protection to the

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[26] *Id*. at 19.
[27] *Id*.
[28] *Id*. at 20.
[29] Mr. Booth explained that, "3V0 provides system fault protection to prevent DER generation from contributing to transmission faults and is required once DER capacity reaches certain thresholds on distribution feeders. Once that threshold is met, additional DER projects may not advance until 3V0 is installed. The Company currently installs 3V0 protection in newly constructed substations and has been retrofitting select existing substations with 3V0 in the ISR Plan since FY 2019." Booth Report at 37.

distribution system while advancing the goal of facilitating greater amounts of distributed energy resources (DER), he reiterated caution about "the magnitude of investments that are absorbed in the ISR Plan to support a subset of DER projects…[noting that] at some point, the customer benefits may not outweigh the costs."[30] Positing that those concerns will ultimately be reviewed and addressed as part of future ISR and Grid Modernization Plan filings, he reiterated his support for the FY 2023 spending.[31]

Similarly, Mr. Booth expressed concern with the status of separately filed grid modernization and advanced metering functionality business cases by National Grid which were put on hold during the review of PPL's plan to purchase the stock of The Narragansett Electric Company. He indicated that this uncertainty presents a dilemma for the Division given the uncertainty of the new company's planning processes and investment strategy.[32] While expressing concern that progress has been stalled on advanced metering and grid modernization, Mr. Booth stated that the Company had appropriately removed forecasted spending ranging in excess of $25 million on unapproved grid modernization activities from the FY 2023 ISR Plan.[33] The long-term challenge, according to Mr. Booth will be how the utility prioritizes and schedules projects informed from Long-Range plans while incorporating requirements arising from separate but interrelated dockets. He noted that "[t]here will be significant upward pressure on the ISR budget to accommodate future projects and initiatives while balancing the competing interests of safety and reliability with economic impacts to ratepayers."[34]

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[30] *Id*. at 38.
[31] *Id*. at 37.
[32] *Id*. at 38-39.
[33] *Id*. at 46-47.
[34] *Id*. at 55.

In sum, Mr. Booth supported the filed FY 2023 Electric ISR Plan and made several specific recommendations for the Commission to consider.[35] The recommendations built on prior years 'recommendations and focused on areas of distribution system planning, appropriate cost allocations, additional transparency in the planning and budgeting process, and various cost benefit analyses. He also included the new recommendation, noted above, about transparency in the ISR personnel and planning processes.

Turning to revenue requirement, Mr. Bell stated that the Division had reviewed with its consultant, David Effron, the revenue requirements and calculations. Mr. Bell indicated that the Division found the calculations to be accurately calculated. Referencing potential tax implications that could occur in FY 2023 should there be a finalization of a transaction between The Narragansett Electric Company and PPL Corporation before the end of the fiscal year, Mr. Bell noted that:

> If the sale to PPL Corporation closes as National Grid expects, the impact on the balance of accumulated deferred federal income taxes ("ADIT") will extend well beyond any additional NOL utilization. As indicated in Docket D-21-09 before the Division, PPL Rhode Island and National Grid USA have elected to have the Transaction treated as an asset sale for federal income tax purposes. This means that the new the tax basis immediately following the acquisition will equal the book basis, and there will be no balance of ADIT at that time. The balance of ADIT deducted from Narragansett's rate base for ratemaking purposes, including the ADIT applicable to the ISR rate base, will be eliminated.
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> In Docket D-21-09 before the Division, PPL stated that it would make a proposal to hold customer impacts neutral in relation to the rate impacts associated with the elimination of ADIT as of the date of the Transaction. As it will be PPL that formulates and presents the specific mechanism to hold customers neutral from the elimination of ADIT, National Grid cannot make any representation as to what the nature of the necessary mechanism might be. However, the Fiscal Year 2023 ISR revenue requirement reflects the balances of ADIT under continued National Grid ownership of Narragansett, and this is appropriate.[36]

[35] *Id*. at 57-60.
[36] Bell Mem. at 2 (Feb. 18, 2022).

This means that while there is uncertainty in the mechanism to be applied to hold customers harmless, the FY 2023 revenue requirement reflects conditions as they exist at the time of the Commission's review of the FY 2023 Electric ISR Plan.

III. Discovery

While the Division and Commission explored a multitude of issues through the issuance of data requests, the following two sets are highlighted because these issues are specifically addressed in the Commission's findings.

Dyer Street Substation

Referencing the Company's description of the Dyer Street Substation scope change, the Commission issued five data requests directed to the Company.[37] In their responses, the Company provided the timeline of the project sanctioning and re-scoping; the original scope as provided in its Sanction Paper; additional information associated with the Five-Year Budget covering the project(s); additional information about costs included in the Sanction Paper for the original and current project; and the ratemaking treatment of costs related to the original project. The data requests were prompted by a question of whether the Company was appropriately allocating costs to the current Dyer Street project following abandonment of the previously presented solution.

Customer Requests – System Modification Costs for Distributed Generation

When any customer, whether it be a load customer, a governmental entity, or a distributed generation (DG) customer pays to the Company all or part of the cost of capital investment, the Company records that capital investment in its rate base net of any payment received from the customer. In the case of distributed generation customers, the Company

[37] National Grid's Responses to PUC 3-1 through PUC 3-5; https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5209-NGrid-DR-PUC-Set-3-%28PUC-3-8-22%29.pdf.

assesses the costs of System Modifications which are defined as Modifications or additions to Company facilities that are integrated with the Company EDS for the benefit of the Interconnecting Customer.[38] After review of a data response in an unrelated matter showing a final accounting of costs assessed to and paid for by a DG customer, the Commission issued a data request in this docket attempting to determine whether the project costs were being given the appropriate ratemaking treatment.[39]

IV. Hearing

On March 9, 2022, the Commission conducted an evidentiary hearing on the proposed Electric ISR Plan at its offices at 89 Jefferson Boulevard, Warwick, Rhode Island. National Grid presented Ms. Easterly, Mr. Moe, Ms. Little, and Mr. Gallagher in support of the Electric ISR Plan. In addition, the Company presented Ryan Constable, Manager of Distribution Planning and Asset Management in Ms. Broderick's place along with David Arthur, Acting Director of Project Management, New England, Vishal Ahirrao, Manager Customer Energy Integration (CEI) Strategy and Support, and Timothy Roughan, Director of Regulatory Strategy for National Grid, each of whom had sponsored responses to data requests.

At the commencement of the hearing, Company Attorney Marcaccio renewed previously filed Motions for Confidential Treatment as to certain documents that the Company claimed were protected from public disclosure under the Access to Public Records Act. The responses included "critical energy infrastructure information" that, if released, could be impact reliable and safe service. He stated that the Company also believed it was required by law to be kept confidential. Other responses included certain bidding information

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[38] Tariff RIPUC No. 2258 (September 1, 2022).
[39] National Grid's Response to PUC 2-7 (Supplemental); https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5209-NGrid-Electric-ISR-FY2023-Supplemental-PUC-2-7-%28PUC-3-4-22%29.pdf.

of private entities, that if released, could jeopardize the competitive process and hurt the Company's ability to run successful solicitations, particularly with respect to non-wires solutions. He claimed protection of this information as competitively sensitive. No objection was offered by the other parties. The Motion was granted. The information is not considered a public document and therefore, exempt from disclosure under the Access to Public Records Act, R.I. Gen. Laws § 38-2-2(4)(B).[40]

System Modification Costs for Distributed Generation

Addressing the allocation of customer payment allocation to DG interconnection system modification costs and to rate base, on direct examination, Ms. Easterly indicated that she had reviewed the Company's response to PUC 2-7 and stated that the Company would be undertaking a review of DG projects. She indicated that the review would include project reconciliations by cost type, how project contributions are classified and accounted for by cost type among other specific items. She projected completion of the review and a report to the Commission and Division by August 20, 2022 so the impact of the review could be included in the FY 2022 ISR Reconciliation filing.[41]

On cross examination, Ms. Little explained that the ratemaking treatment of a capital asset place in service for which there was a customer contribution, is to include only in rate base what was not paid for by the customer.[42] In the instance of a DG interconnection, the customer is provided with an Interconnection Services Agreement that has an estimate that is designed to cover the cost of the project. Under the Company's tariff,[43] the Company can

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[40] Hr'g. Tr. at 9-12 (Mar. 9, 2022); Motion for Confidential Treatment (Jan 19, 2022).
[41] Hr'g. r. at 15-16, 69.
[42] Hr'g. Tr. at 75-76.
[43] Standards for Connecting Distributed Generation (RIPUC 2180).

collect up to 10% over that amount.[44] Any amount collected in excess of the cost of the required System Modifications is refunded to the customer.[45] In the event the Company does not inform the customer of an increase in costs, the Company does not charge the customer for the increased cost, but rather, the Company has been applying the excess amount to the rate base calculation.[46] Thus, regardless of whether the Company's costs come within the estimate, it is made whole so in essence, ratepayers are taking on the risk of the reliability of the Company's estimates to project costs.[47]

In addition to the review of the allocation of costs as explained by Ms. Easterly during direct examination, she indicated the review could also include looking at all DG projects where the customer contribution did not cover the full cost of the project; the reasons why; and how much that impacted the revenue requirement.[48] She also agreed it would be logical for the Commission to then go back and review how those project had been treated.[49]

Dyer Street Substation

Another issue explored at the hearing was the categorization of expenses of the Dyer Street Substation, including whether the project had been re-scoped or whether there were two projects, one of which was abandoned. This is an important distinction for ratemaking purposes. Mr. Arthur reviewed the timeline of the evolution of the Dyer Street Substation project from the initial decision to reutilize the DC building and demolish the AC building at Dyer Street through the decision to still demolish the AC building, but, instead of reutilizing the DC building, to move the project to the location of the South Street Substation a half mile

[44] Hr'g. Tr. at 88; Mr. Roughan testified that the estimate is considered to be a construction grade estimate. *Id*. at 84-85.
[45] Hr'g. Tr. at 122.
[46] Hr'g. Tr. at 77-78.
[47] Hr'g. Tr. at 109-10.
[48] Hr'g. Tr. at 118-20.
[49] Hr'g. Tr. at 120-21.

away.[50] The Company had originally designed a solution at the Dyer Street location, but once it issued the project for bids, the costs came back significantly higher than expected, leading the Company to design an alternative solution to the problem within the same budget.[51]

Mr. Arthur explained that both plans include demolishing the AC building at the Dyer Street location. After the redesign, Mr. Arthur explained, certain costs from the initial design and planning were transferred to the current project design. He indicated he had a separate accounting of that.[52] However, he testified that because the Company was looking at Dyer Street as one project initially, he had not performed an analysis to distinguish between the costs associated with the AC building and the costs associated with rebuilding the DC building in the first design.[53] Ms. Little confirmed that all of the costs associated with the DC building redesign would be assigned to the new South Street Station project, put into rate base, and earn a return.[54] While Mr. Arthur disagreed that the Company had abandoned the initial project, he conceded that the idea of building a substation in the DC building was abandoned.[55] Ms. Little testified that even if there were some duplication of costs between the re-scoped projects, if prudently incurred, they should be accounted for and allowed into rate base as an ultimate benefit to the South Street project. She did, however, agree that if "there's some portion of those costs that's deemed to be not beneficial to the South Street

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[50] Hr'g. Tr. at 20-27, 34-35, 56-57.
[51] Hr'g. Tr. at 21,
[52] Hr'g. Tr. at 36. In response to RR-1, Mr. Arhur provided that, "The amount transferred from preliminary survey & investigation to the Dyer Street project was $143,015. Amounts were transferred in March, June, and August 2017." In response to RR-2, Mr. Arthur and Ms. Little indicated that, "The Company paused the project in February 2020 when $1.980 million of project costs were incurred. This total includes capital spending of $0.234 million on the Distribution Line project which supports the South Street (Dyer) project. The Company estimates that $0.855 million of the remainder of $1.746 million relates to the DC building and the remainder of $0.892 million relates to the South Street (Dyer) project. Additional costs of $10,189 related to the DC Building were incurred after February 2020 due to finalization of invoicing."
[53] Hr'g. Tr. at 34-35.
[54] Hr'g. Tr. at 43-44.
[55] Hr'g. Tr. at 44.

project going forward, those would be written off of the balance sheet and they would be recorded to the income statement and absorbed in that period."[56]

Pause on Volt Var Optimization Activities

The Company had previously engaged in a volt-var optimization (VVO) pilot to study the benefits versus the costs of automated optimization of voltage at the distribution feeder level. Typically, voltage falls as one moves further down a feeder toward the source of customer usage. VVO senses that an increases voltage to the level needed for customer equipment to run efficiently.

Based on the positive results, the Company had been moving toward a full programmatic roll-out of VVO. Mr. Constable explained that the Company had paused this pathway in order to look at VVO in the context of a more comprehensive grid modernization proposal. He stated that in the comprehensive approach, one might not prioritize VVO in the same way as if it were a standalone proposal.[57] Mr. Constable explained that the Company was concerned that when reviewed alone, the VVO benefits could be eroded as more DG is interconnected to the system because DG tends to raise voltage.[58]

Mr. Constable explained that the expected Advanced Distribution Management System that would be used if a merger occurred between National Grid and PPL would be capable of integrating VVO and that VVO would still be part of an overall grid modernization plan.[59] With respect to performing a benefit cost analysis for grid modernization, Mr. Constable testified that even though the Company had been planning to expand the VVO

[56] Hr'g. Tr. at 47-48.
[57] Hr'g. Tr. at 157-60.
[58] Hr'g. Tr. at 161-62.
[59] Hr'g. Tr. at 161-65.

investments, it would, nonetheless, run the benefit cost analysis with a baseline assumption of no VVO. He explained that otherwise, the costs of VVO would get lost in the analysis.[60]

Previously Approved Grid Modernization Investments

The Commission had previously approved various funding for investments represented to be foundational investments needed to advance a modern grid regardless of the grid modernization plan ultimately approved by the Commission.[61] In discovery, the Company had provided updates on the progress of those investments. At the hearing, Mr. Constable explained how those investments could be used in the future, even if a merger were effectuated between National Grid and PPL. However, until the merger was complete, he was unable to fully respond to certain questions.[62]

V. Commission Findings

At an Open Meeting on March 29, 2022, the Commission considered the evidence and approved the FY 2023 Electric ISR Plan, filed on December 20, 2021. The approved revenue requirement was $49,721,324, resulting in an incremental fiscal year upward rate adjustment of $8,363,605. This will support a FY 2023 Electric ISR Plan capital budget of $104,750,000, a vegetation management budget of $11,875,000, an infrastructure and maintenance (I&M) budget of $1,015,000, and other expense of $249,000.[63] The Commission also adopted all of Mr. Booth's recommendations.

The Commission notes that management is getting more expensive. As vegetation management contracts are coming in over the course of this year and the Company is planning

[60] Hr'g. Tr. at 166-68.
[61] See PUC 1-8.
[62] On May 25, 2022, PPL Rhode Island Holdings, LLC, an indirect wholly owned subsidiary of PPL Corporation, acquired 100 percent of the outstanding shares of common stock of The Narragansett Electric Company, now doing business under the name Rhode Island Energy. On July 12, 2022, Rhode Island Energy filed an update to PUC 1-7, 1-8, and 1-9 as RR-9 for informational purposes.
[63] *Id.;* Easterly, Moe, and Castro Joint Test. at 12 (hereinafter "Joint Test."); Electric ISR Plan at Section 5: Attachment 1, page 1.

for next year, the Company and the Division should examine whether there are potential benefits to accelerating, delaying, modifying or otherwise adjusting the Company's cycle pruning or other tree management programs based on current and forecast costs. The Company should include such information in its filing.

With respect to the Dyer Street substation project no decision is needed in this case as to the appropriate ratemaking treatment of the costs associated with the initial project or rescoped project because there will be no rate impact until the assets are placed into service. The question at that time is unlikely to be whether the decision to change locations to solve the distribution system problem was prudent, but rather, whether the initial project costs associated with the reutilization of the DC building should be considered part of the same project or whether they should be considered abandoned for ratemaking purposes.

It appears that the project currently labeled as the Dyer Street substation project is different from the one previously reviewed by the Commission. However, the Company seems to be assuming it will receive cost recovery of the first project as part of the new project proposal as capitalized costs upon which it will be allowed to earn a return. The Commission cautions against this assumption. Typically, for ratemaking purposes, once a project is abandoned, costs are to be recorded as an operating expense.

It is not enough that a cost is prudently incurred. That is only the first step of determining whether a capital expense which may be included in rate base as capital upon which the Company can earn a return. The Company will need to make the case to seek recovery of these costs because it is not completely clear that these costs should be recorded as capital expense. Thus, when the South Street station is completed, the Company needs to provide clear and granular data that separates out the costs associated solely with the Dyer Street project and those associated with the South Street project. If the Company wants to recover any of the costs associated with the abandoned project, they need to make a case. To reiterate Ms. Little's testimony from the hearing, if "there's some portion of those costs that's deemed to be not beneficial to the South Stret project going forward, those would be written off of the balance sheet and they would be recorded to the income statement and absorbed in that period."[64]

With respect to the recovery of customer contributions for System Modifications associated with DG interconnections in instances where the Company did not collect 100% of the costs to interconnect from the DG customer, the Company indicated that it would be further reviewing the issue and accounting practices and would endeavor to provide a report to the Commission by August 1, 2022, in conjunction with its ISR Reconciliation filing. At the hearing, the Company agreed to include in its review all DG projects for which the customer contributions did not cover the full cost of the project, the reasons why, and the impact on rate base and the associated revenue requirement. The report shall include these items and be filed no later than August 1, 2022, with the Reconciliation of the of Electric ISR filing with all necessary adjustment to any ISR revenue requirement/reconciliation explained and highlighted.[65] The Commission clarifies that this is not a ruling on the propriety of recovering the interconnection costs until the Commission has had the chance to review the Company's report.

[64] Hr'g. Tr. at 47-48.
[65] In the August 1, 2022 Reconciliation Filing for the FY 2022 Electric ISR Plan, Ms. Easterly provided an update of a review of how contributions for capital spending on DG projects is allocated by cost type. While the Company had not completed its review, Ms. Easterly explained that the preliminary review resulted in an adjustment of $391,000 that was made through this reconciliation filing to plan t additions from rate base. The result was a reduction to the reconciliation factor. Order No. 54560 at 3 (Dec. 23, 2022).

Accordingly, it is hereby

(24607) ORDERED:

1. The Narragansett Electric Company d/b/a National Grid's FY 2023 Electric ISR Plan, filed on December 20, 2021, is hereby approved.

2. The Narragansett Electric Company d/b/a National Grid shall provide, as part of its FY 2024 filing, details on individual projects where the costs differ from budget by more than 10%, whether that difference resulted from over- or under-spending or timing.

3. The Narragansett Electric Company d/b/a National Grid shall follow the Division of Public Utilities and Carriers' recommendations that were filed on February 18, 2022.

4. Contemporaneous with its filing of the FY 2023 Electric Infrastructure, Safety, and Reliability Plan, The Narragansett Electric Company d/b/a National Grid shall file a cost-benefit analysis consistent with the Guidance Document issued in Docket No. 4600-A.

5. Narragansett Electric shall include in its review of the allocation of customer contributions to the proper cost categories all distributed generation projects for which the customer contribution did not cover the full cost of the project; the reasons why; and the impact on rate base and the associated revenue requirement. The report shall be filed no later than August 1, 2022, with the Reconciliation of the Electric ISR filing with all necessary adjustments to any ISR revenue requirement/reconciliation explained and highlighted.

6. The Narragansett Electric Company d/b/a National Grid's Motion for Protective Treatment of its responses to Division 3-2 which contains critical energy infrastructure information and Division 3-3 that contains bidder-specific information that, if released, could adversely affect future competitive solicitations, is hereby approved.

7. The Narragansett Electric Company d/b/a National Grid shall comply with all other instructions contained in this Order.

EFFECTIVE AT WARWICK, RHODE ISLAND, ON APRIL 1, 2022, PURSUANT TO AN OPEN MEETING DECISION ON MARCH 29, 2022. WRITTEN ORDER ISSUED FEBRUARY 28, 2023.

PUBLIC UTILITIES COMMISSION

Ronald T. Gerwatowski, Chairman

Abigail Anthony, Commissioner

John C. Revens, Jr., Commissioner

Notice of Right of Appeal: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the Commission may, within 7 days from the date of the Order, petition the Supreme Court for a Writ of Certiorari to review the legality and reasonableness of the decision or Order.