STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NATIONAL GRID'S ELECTRIC INFRASTRUCTURE, SAFETY, AND RELIABILITY PLAN FY 2018 PROPOSAL	:	DOCKET NO. 4682

REPORT AND ORDER

I. National Grid's Filing

On December 20, 2016, The Narragansett Electric Company d/b/a National Grid (National Grid or Company) filed with the Public Utilities Commission (PUC or Commission) its proposed Electric Infrastructure, Safety, and Reliability Plan (Electric ISR Plan) for FY 2018.[1] National Grid indicated that the Division of Public Utilities and Carriers (Division) had reviewed the proposed Electric ISR Plan and had agreed to the spending portion but was continuing its review of particular provisions during the PUC's review.[2] On March 7, 2017, National Grid filed an updated revenue requirement to reflect

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[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 subsection (d) herein….(d) 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 2018 Electric ISR Plan and all of the documents referenced herein can be found on the PUC's website at: http://www.ripuc.org/eventsactions/docket/4682page.html.

[2] Filing Letter at 1 (Dec. 21, 2016).

the effect of its income tax filing which was made with the Internal Revenue Service after the filing date in this docket.[3]

On March 9, 2017, after conducting discovery and a hearing, the PUC approved the Electric ISR Plan and the revised revenue requirement conditioned on adoption of all the recommendations made by Division witness Gregory L. Booth. The overall revised revenue requirement was $26,837,179, resulting in an incremental fiscal year downward rate adjustment of $866,645.[4] This decrease will support a FY 2018 Electric ISR Plan capital budget of $100,621,000, a vegetation management budget of $9,400,000, and an infrastructure and maintenance (I&M) budget of $1,069,8000.[5]

A. Electric ISR Plan

In support of the Electric ISR Plan, National Grid submitted the direct testimony of National Grid employees James H. Patterson, Director, Network Strategy for New England, and Ryan A. Moe, Vegetation Strategist (collectively, the plan witnesses). In support of the development of the revenue requirement and to explain the reconciliation process, National Grid submitted the joint direct testimony of its employee Melissa A. Little, Lead Specialist for New England Revenue Requirements, and Aidimarys Martinez, Lead Analyst for 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 submitted the direct testimony of its employee Adam S. Crary, Senior Analyst for Electric Pricing.

The plan witnesses indicated that the proposed Electric ISR Plan covered three budget categories for the fiscal year ending March 31, 2018: capital spending on

[3] Revised Revenue Requirement; http://www.ripuc.org/eventsactions/docket/4682-NGrid-Revised-RR&BllImpacts_%203-7-17.pdf.
[4] Revised Revenue Requirement at Revised Section 5: Attachment 1S at 1.
[5] FY 2018 Electric ISR Plan at 6, 8, 12, 13, 68, 90, and 96 (Bates stamp references).

infrastructure projects, operation and maintenance expenses (O&M) for vegetation management, and O&M expenses for an inspection and maintenance (I&M) program.[6] 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."[7]

The proposed capital spending plan for FY 2018 is $100.6 million.[8] 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).[9] 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."[10] These items, totaling $33,232,000, account for 33% of the proposed capital outlays in FY 2018.[11]

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.[12] These items together comprised the other 67% of the FY 2018 budget. Specifically, the System Capacity

[6] Patterson and Moe Test. at 5.
[7] *Id.*
[8] *Id.* at 6, 8.
[9] *Id.* at 7.
[10] *Id.* at 8-9.
[11] *Id.* at 8-9.
[12] *Id.* at 9-11.

costs of $24,092,000 made up 23.9%; Asset Condition costs of $16,971,000 made up 16.9%; and Non-Infrastructure spending of $553,000 made up the remaining 0.5%.[13] A single large project, the FY 2018 South Street Station asset replacement project budget of $25,773,000 (25.6% of the entire ISR budget), was addressed in three areas of National Grid's filing. The plan witnesses explained that, per the PUC Order approving the FY 2017 Electric ISR Plan, the Company will continue to manage the South Street project budget separately from the overall discretionary budget.[14]

The Electric ISR Plan also includes the proposed FY 2018 spending levels for the Company's Vegetation Management Program of approximately $8.9 million and finally, the I&M spending includes capital amounts already accounted for above plus $1.3 million for O&M costs related to the I&M program.[15] The Company agreed to provide the PUC 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 explanation of significant deviations to be included in its quarterly and year-end reports.[16]

B. Development of the ISR Factors

Adam Crary, Senior Analyst for Electric Planning, explained that the ISR Factor 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

[13] *Id*. at 8.
[14] *Id*. at 11; Docket No. 4592 (Order No. 22471) (July 11, 2016).
[15] Patterson and Moe Test. at 12-13.
[16] *Id*. at 11-12.

activities. To design the Capital Expenditure factors and develop the incremental capital investment, following Commission review of a cumulative revenue requirement, National Grid applies a rate base allocator which was developed in the most recently approved cost-of-service study. Similarly, the O&M Mechanism is designed to allocate the inspection and maintenance and vegetation management expenses to the 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.[17]

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 requirement to actual billed revenue generated from the Capital Expenditure Factors. Any over- or under-recovery is be 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.[18]

Mr. Crary explained that the Capital Expenditure Factors are designed to collect the cumulative revenue requirement of $16,531,128 attributable to incremental capital

[17] Crary Test. at 3-7; Section 6: Rate Design, Revised. 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." *Id.*. at 7. Furthermore, as a result of two tariffs approved by the PUC for effect February 1, 2013, the Back-Up retail delivery rates were recalculated to reflect a discounted distribution kW charge. The methodology in this filing is different from the prior year, but the result is the same under both methodologies. *Id*. at 9-12.
[18] *Id*. at 5, 7-8.

investments through the end of FY 2018. The cumulative revenue requirement is allocated to the various rate classes as determined by the total rate base allocator that was included in the Commission-approved Amended Settlement Agreement filed in Docket No. 4323.[19] The O&M Factors are designed to collect the $10,306,051 in forecasted FY 2018 I&M and vegetation management O&M activities. The monthly rate decrease on the bill of a typical residential customer using 500 kWh per month would be $0.09 per month.[20]

II. Division's Filing

On February 16, 2017, the Division submitted the testimony and report of its consultant Gregory L. Booth, P.E. and a memorandum from its consultant David J. Effron. The Division generally supported the FY 2018 Electric ISR Plan budget. Mr. Booth, however, noted that full consensus had not been reached and offered recommendations for PUC consideration. Mr. Booth indicated in his memorandum that the filed plan represented a $3.881 million reduction in capital from what was originally presented to the Division in the fall of 2016.[21] Mr. Effron concluded that the revenue requirement had been reasonably calculated.[22]

In general, while noting areas where National Grid's planning processes had improved and should reduce instances of cost overruns resulting from inclusion of budget items too soon in the planning process,[23] Mr. Booth continued to express concern with National Grid's delay in completing the area studies as part of the Company's long range plan process.[24] He continued to discourage advancement of any project without the support

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[19] Crary Rev. Test. at 8.
[20] *Id*. at 9-10.
[21] Booth Test. and Report at 7, 47; http://www.ripuc.org/eventsactions/docket/4682-DPU-Booth_2-16-17.pdf.
[22] Effron Mem. at 1.
[23] Booth Report at 15-17, 30.
[24] Booth Report at 35-37.

of an area study.[25] He cautioned that National Grid's overall planning process lacks a certain transparency and cohesiveness regarding the relationship between the Company's design criteria, System Reliability Procurement and Area Studies.[26] He recommended National Grid align the various planning and project evaluation processes. He also suggested the Company revise future and current study documents to consider non-wires alternatives where applicable. Finally, he sought a proposal from the Company to assign costs for the contact voltage testing program to municipal streetlight owners.[27]

Mr. Booth made several specific recommendations[28] for the Commission to consider:

1. National Grid should align the various planning and project evaluation processes with consideration as to how a grid modernization strategy may be incorporated. This alignment includes, but is not limited to, the System Reliability Procurement, Area Studies, ISR Plan, and internal Design Criteria.
2. National Grid should propose a methodology to revise current and future study documents supporting Asset Replacement and System Capacity programs or projects as applicable to include, at a minimum:
    a. The traditional elements included in the Company's current studies;
    b. The purpose and problem statement, scope and program description, condition assessment/criticality rankings, alternatives considered, solution, cost and timeline;
    c. Discussion on the impact to related Company initiatives, PUC programs;
    d. A detailed comparison of recommendations to Area Studies to determine if solutions are aligned with study outcomes, noting adjustments required to avoid redundancy in planning;
    e. An evaluation of potential incremental investments that support the Company's long-term grid modernization strategy. This includes description of technology or infrastructure investment, cost, benefit to traditional safety and reliability objectives, and additional operational benefits achieved if implemented;
    f. A robust NWA evaluation for projects passing initial screening that clearly identifies alternatives considered, costs, and benefits.

[25] Booth Report at 34.
[26] Booth Report at 37-40.
[27] Booth Test. at 9-10; Booth Report at 19, 21-22.
[28] Booth Test at 12-15; Booth Report at 47-50.

3. National Grid should develop a proposal on the methodology to assign Contact Voltage program costs for the testing and remediation of elevated voltage to municipal streetlight owners.
4. National Grid should continue to develop a System Capacity Load Study and a 10-year Long Range Plan in order to increase the level of support and transparency for the capital budget. The Company shall submit and present the outcome of Area Studies to the Division and its consultant at the time of completion. The Company shall submit a report with updates on modeling activities and Areas Study status at least 120 days prior to filing its FY 2019 ISR Plan Proposal, but in any event no later than August 31, 2017.
5. National Grid should manage major Asset Replacement project budgets separate from other discretionary projects, such that any budget variances (underspend) will not be utilized in other areas of the ISR Plan. The Company shall provide quarterly budget and project management reports.
6. National Grid should continue to manage (underspend/overspend management) individual project costs within the ISR Plan discretionary category (comprised of Asset Condition and System Capacity and Performance projects), such that total portfolio costs are aligned within a discretionary budget target that excludes South Street.
7. National Grid should continue to provide quarterly reporting on Damage/Failure expenditures to include the details of completed projects by operating region. The Company will separately identify Level I projects repaired as a result of the I&M program.
8. National Grid should continue to provide a detailed budget for System Capacity & Performance and Asset Condition in order to provide transparency on a project level basis for the current and future 4-year period. The budget shall be provided in advance of the FY 2019 ISR Plan Proposal filing, but in any event no later than August 31, 2017.
9. National Grid should submit an evaluation of future proposed Asset Condition projects as compared to the Company's Long Range Plan in advance of the FY 2019 ISR Plan Proposal filing, but in any event no later than August 31, 2017.
10. National Grid should continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of proposed projects against the Company's Long Range Plan, in advance of the FY 2019 ISR Plan Proposal filing, but in any event no later than August 31, 2017.
11. National Grid should continue to submit a cost-benefit analysis on the Vegetation Management Cycle Clearing Program and a separate cost-benefit analysis on the Enhanced Hazard Tree Management program for the Division's review prior to submitting the Company's FY 2019 ISR Plan Proposal, but in any event no later than August 31, 2017.
12. National Grid should continue to submit its Metal-Clad Switchgear replacement program cost/benefit analysis to the Division prior to submitting the Company's FY 2019 ISR Plan Proposal, but in any event no later than August 31, 2017.

III. Hearing

On March 9, 2017, the PUC heard evidence on the proposed FY 2018 Electric ISR Plan at its Offices at 89 Jefferson Boulevard, Warwick, Rhode Island.[29] National Grid presented Messrs. Patterson, Moe, and Crary together with Mses. Little and Martinez in support of the Plan. The Company also called on James Perkinson to discuss the expansion of the Volt/Var pilot program previously approved by the PUC and Ryan Constable, to update the PUC on consideration of distributed generation in the planning process as well as to respond to some of Mr. Booth's testimony.[30] The Division called Mr. Booth to testify on behalf of the Division.

Mr. Patterson testified that National Grid generally accepted all of Mr. Booth's recommendations, noting that Company representatives had met with the Division since the filing of Mr. Booth's testimony to clarify the terms of the recommendations.[31] Addressing a proposed change to the contact voltage testing program suggested by Mr. Booth, Mr. Patterson explained that testing the statutory minimum of 20% of the contact voltage test areas rather than the previously approved 100% would reduce the cost of testing by a third. He noted that most of the contact voltage has been found associated with streetlights and indicated that the Company would likely focus on Providence in the first year as that is where the majority of contact voltage "hits" were found during mobile testing.[32]

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[29] Attorneys Raquel Webster and Jennifer Brooks Hutchinson appeared on behalf of National Grid. Attorney Andrew Marcaccio represented OER. Assistant Attorney General Leo Wold represented the Division and Attorney Cynthia G. Wilson-Frias represented the PUC.

[30] On December 19, 2016, the PUC held a Technical Record Session at which Mr. Perkinson provided the preliminary results of the Volt/Var pilot. A copy of the presentation can be found at: http://www.ripuc.org/eventsactions/docket/4592-NGrid-Volt-VarUpdate(12-12-16).pdf. On that same day, the Company provided an update of its consideration of distributed generation in system planning. A copy of that presentation can be found at: http://www.ripuc.org/eventsactions/docket/4682-NGrid-Overview-DPlanningPresentation(12-19-16).pdf.

[31] Hr'g Tr. at 15-17 (Mar. 9, 2017).

[32] *Id*. at 33-36, 131.

During his testimony, Mr. Booth stated that the new technology that was used for the first time last year had proven effective. He contended that, with the municipalities purchasing streetlights from National Grid, the costs should be borne more equitably between the Company and the municipalities. Mr. Booth stated that his experience was that municipalities that own streetlights do not typically engage in testing them for contact voltage. Accordingly, he surmised that the Company will likely retain the responsibility for testing but recommended a portion of the costs be allocated to the municipalities.[33]

Mr. Perkinson provided an update on the Volt/Var program, which is designed to automate voltage control and give National Grid greater visibility on the distribution system. He offered that the Company had now installed 97% of the devices. The remaining devices would be installed on the Tower Hill circuits. He explained that National Grid was working with Verizon to install higher poles to support the additional weight. He expected all of the devices to be installed by April 1, 2017. He had no additional results to share with the PUC beyond the initial results on the Putnam Pike feeders, which were presented in December, 2016.[34] The preliminary results in the Putnam Pike area yielded a net positive for voltage regulation, reduction, and cost savings.[35]

Mr. Booth testified that Volt/Var with the communications devices provides some of the same benefits as advanced metering infrastructure. He indicated that it could be viewed as a form of grid modernization because it provides more visibility on the system. It does not, however provide the same level of detail as advanced metering infrastructure. He explained that one role of the Division in the ISR has been to make sure that the Company

[33] *Id.* at 150-57.
[34] *Id.* at 48-52.
[35] Rhode Island Volt VAR Optimization & Conservation Voltage Reduction, Slides 4-9 (Dec. 2, 2016); http://www.ripuc.org/eventsactions/docket/4592-NGrid-Volt-VarUpdate(12-12-16).pdf.

does not invest in technology that will be obsolete in a few years. The goal should be to invest in technology that will be easily transitioned into a more robust grid and modernized system.[36]

Mr. Perkinson explained that the Company intends to expand the program to selected areas. The three substations and associated feeders identified for FY 2018, Langworthy Corner, Lincoln, and Tiogue, were chosen based on minimal cost, maximum benefit, and no need of major infrastructure upgrades in the near term.[37] While the O&M costs for Volt/Var are currently being requested through the ISR program, Mr. Patterson indicated that the treatment of these costs would need to be reviewed in the next distribution rate case to determine whether they should be rolled into general O&M costs or remain separate.[38]

In response to Mr. Booth's direct testimony, Mr. Constable conceded that the area studies had been taking a long time to complete. He expected that the times would improve because the next study areas are less complex than the Providence area study.[39] He explained that part of the delay resulted from revising internal documents to make them more transparent and understandable to external parties, such as the Division.[40] Mr. Booth agreed that the upcoming studies are less complex and that National Grid has been responsive to requests for adjustments and clarifications to the draft area studies. He expected all area studies to be complete within the upcoming two years.[41]

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[36] Hr'g. Tr. at 175-78.
[37] 52-54.
[38] *Id*. at 58.
[39] *Id*. at 60.
[40] *Id*. at 57-58.
[41] *Id*. at 166-69.

Mr. Constable characterized the incorporation of distributed generation and non-wires alternatives into the distribution planning process as "a journey." While the Company's internal processes require the consideration of each, there are no set rules yet for the distributed generation piece. Additionally, there are ongoing conversations about the appropriate criteria for the non-wires alternatives. He explained that these issues have been looked at in several stakeholder settings and the distribution planning process will continue to evolve in order to ensure the Company can meet state policies while also providing safe and reliable service.[42] Mr. Patterson indicated that safeguards will also need to be instituted to address the appropriate cost recovery in order to avoid double counting, particularly where projects include a hybrid solution of partial capital investment and partial non-wires alternatives.[43]

Discussing the status of some of the discussions, such as the development of a heat map to guide further refinement of appropriate criteria for the consideration of non-wires alternatives, Mr. Constable provided some cautionary points. Currently, the Company identifies areas for infrastructure upgrades when the loading reaches 100% of the rating. Under a heat map approach, the Company may look at areas that are at 90% of capacity and begin to develop alternatives there. Mr. Constable indicated that a risk to this is that load may never reach the 100% and a non-wires investment may have been done unnecessarily. Alternatively, if the non-wires alternative were advanced in order to avoid the 100% and need for additional investment that would have occurred absent the non-wires alternative,

[42] *Id*. at 68-97.
[43] *Id*. at 75-76.

that would be a benefit for customers. The important thing to do is find the right balance between the two.[44]

Additionally, while the heat map may send a signal to project developers that there may be a capacity constraint in that area that could be met through distributed generation, the heat map will not address things that may result in high interconnection costs. For example, depending on the characteristics of a facility, it may cause its own peak or result in other electrical issues that would raise the cost of interconnection. He agreed that a heat map could guide where development of distributed generation may be beneficial on the system as a non-wires alternative, but would not necessarily show the most cost-effective development areas for those generators.[45]

A potential solution to the problem of identifying the places on the system where distributed generation may make the most sense but is not cost-effective for the developer is the development of a hosting capacity map. Mr. Constable explained that several attempts have been made at doing that and there has been progress. He indicated that the Electric Power Research Institute has come up with a more comprehensive model that takes into account system issues. It is a fairly complex model that requires significant data and computing power. According to Mr. Constable, there are some indications that the CYME power engineering software National Grid uses may develop a hosting capacity functionality that will be ready in the near future. If so, the Company could review it and determine if it could obtain the software to simplify that iterative process.[46]

[44] *Id*. at 80-83.
[45] *Id*. at 93-95.
[46] *Id*. at 96-98.

IV. Commission Findings

At the conclusion of the hearing, the PUC approved the FY 2018 Electric ISR Plan with the revised revenue requirement, finding that it complied with the statutory mandates. As part of its approval, the PUC adopted Mr. Booth's recommendations. In addition, the PUC directed that commencing with the third quarterly report, the Company should include updates on new technologies it is exploring in the context of distribution system planning.

This is the seventh Electric ISR plan the PUC has reviewed since passage of the decoupling statute which required implementation of ISR plans. As the PUC has continued to review electric ISR plans, the focus has evolved from a straightforward exercise of reviewing capital investment under traditional planning rules to the PUC taking a more active role and requiring the Company to show how distribution system planning has evolved to take into account State energy policy. It is in the context of its review of the electric ISR plans that the PUC began its journey toward the Docket 4600 rate modernization case, designed to develop a means to align all rates with State energy policy in a least cost manner.

As part of the third program year (FY 2014 Electric ISR Plan), National Grid proposed a study to compare the traditional methods of optimizing circuits with advanced automated control methods. Following completion of the study, in its FY 2015 Electric ISR Plan, National Grid proposed a pilot that would "integrate the centralized controls while [National Grid was] doing the traditional methods so that [National Grid] got the right placement of all the equipment that would work with the centralized controls."[47] In that proceeding, Mr. Perkinson explained that the purpose of Volt/Var optimization is to control the voltage to customers in a way that results in energy usage savings. The percentage of

[47] Order No. 21559 (Docket No. 4473) at 20 (Aug. 12, 2014).

savings was not yet known, but had an expected range between a half percent and seven percent. However, he stated that "[t]he assumption underneath all this is if you control the voltage at the load, that somewhere within the allowable band that we can deliver it," the amount of energy used in the house is going to be adjusted.[48] Other benefits include peak shaving, extending the life of infrastructure, and lessened energy procurement.

While reviewing the FY 2015 Electric ISR Plan, the PUC first directly raised the question of whether National Grid was drawing from the "right" source of funds. The PUC queried whether the Volt/Var program could be considered an energy efficiency measure and in response, Mr. Perkinson stated that after the pilot, when considering a larger rollout, it may be appropriate to look at it as energy efficiency.[49] National Grid witness Jennifer Grimsley added that it might be appropriate, following the pilot, to have some type of hybrid cost recovery model. Perhaps a certain part of the program would be recovered as traditional capital infrastructure while some of the new components on the centralized control could be part of a model recovered as an energy efficiency measure.[50]

The following year, after declining intervention to a renewable energy developer, the PUC, in its findings on the FY 2016 Electric ISR Plan, stated:

> Finally, an issue that garnered significant discussion was long range planning and how the ISR planning process should look in light of the increase in distributed generation resources along with the other legislative mandates of energy efficiency and system reliability. Each of these programs has a cost component and is reviewed by the PUC individually. Like a utility cannot be certain it is expending funds and allocating resources in the most cost effective and efficient manner by conducting year to year review absent long range studies and comprehensive system plans, the PUC cannot be certain that the rates being approved in each of these separately mandated cases is producing rates that are, on the whole, just and reasonable.

[48] *Id.*
[49] *Id.* at 21.

There needs to be a mechanism by which the PUC can determine whether these programs are truly integrated and working together to the overall benefit of ratepayers or whether as a standalone program, the cost benefit analysis is reasonable, but together, they are doing little more than shifting costs around, or worse, are duplicating costs. Nowhere is this more concerning than in the arena of large distributed generation projects.

National Grid has admitted that, partially due to the nature of the distributed generation application process, there is little integration of the distributed generation program into the overall planning process. To a certain extent, this is understandable because predicting where a developer may wish to site distributed generation is out of National Grid's control as is where a developer may wish to site load. Furthermore, the uncontroverted testimony was that until there is a reasonable certainty that the utility will be able to rely on the customer-sided generation during extended periods of peak demand over the long-term, it is difficult to value the resource and integrate it into the planning. However, some of these unknowns would be more predictable if National Grid were to create a system plan that would provide information to developers and consumers regarding the most efficient areas for siting of distributed generation.

Even now, there needs to be consideration in the planning process to anticipate growth of distributed generation spurred by, at the minimum, existing state policy, programs, and market forces. Such planning for generation growth is analogous to planning the distribution system for load growth. Furthermore, the long range plans should consider the extent to which the current system is prepared for generation growth, which requires some understanding of the least cost siting of reasonably anticipated generation growth on the current system. Additionally, long range plans should consider how designing for growth in load and distributed generation can be mutually beneficial; for example, investigating how new infrastructure necessary to serve load in one area can be designed to also serve generation at a lower cost than designing for load alone, or at a lower cost than designing to serve load in one area, while designing to serve generation in another. The long-range studies and system plan that Mr. Booth has been advocating over the past several years are a step in the right direction. Testimony in this docket supported the ability of long-range studies to take system reliability, energy efficiency and distributed generation considerations into account. The long-range studies need to include consideration of distributed generation on the distribution system.[51]

As part of its review of the FY 2017 Electric ISR Plan, in response to the PUC's findings, National Grid presented Ryan Constable, Distribution Planning Manager, and Timothy Roughan, Director of Energy Environmental Policy, to provide a presentation on the distribution planning process. As part of the presentation, Mr. Constable explained how

[51] Order No. 22174 (Docket No. 4539) at 25-26 (Oct. 21, 2015).

distribution planning is undertaken generally. He then explained how energy efficiency and demand response are being considered in the distribution planning process. Finally, he discussed how additional visibility on the distribution system might be generated in order to provide more tools for the forecasting process and how distributed generation might be better integrated into the forecasting and planning processes.

It is the goal of each state agency that forms energy policy, guides energy policy, and reviews the regulatory mechanisms that state energy policy be implemented at least cost to all ratepayers. During the period between 2014-2016, the Rhode Island Office of Energy Resources was working through a Systems Integration stakeholder group, resulting in a Systems Integration Rhode Island (SIRI) report that looked at ways the Company might integrate distributed energy resources more efficiently. This year it is clear, especially after reviewing the Order in Docket No. 4539 (FY 2016 Electric ISR Plan), that the Company has made strides in responding to the calls of the various state agencies.

As Mr. Constable explained, there is still a great deal of work to be done as the distribution planning process continues to evolve. For example, the long-range area studies must be completed expeditiously and must meet safety and reliability concerns. The Company, nevertheless, appears to be seriously considering its role in the planning process to efficiently, and cost-effectively integrate distributed energy resources and non-wires alternatives onto the distribution grid in manner that promotes safety and reliability of service. Such willingness on the part of National Grid to follow PUC directives and participate in other state agency processes has helped advance the journey toward development of more efficient ratemaking.

Accordingly, it is hereby

(22955) ORDERED:

1. The Narragansett Electric Company d/b/a National Grid's Revised Electric Infrastructure, Safety, and Reliability Plan FY 2018 Proposal, filed on December 21, 2016, and associated compliance tariffs, filed on March 31, 2017, are hereby approved for electric consumption on and after April 1, 2017.

2. The Narragansett Electric Company d/b/a National Grid shall provide, as part of its FY 2019 filing, more detail to support the purported need for the investments, particularly for multi-year projects or those classified as "major programs" within a category.

3. The Narragansett Electric Company d/b/a National Grid shall provide, as part of its FY 2019 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.

4. The Narragansett Electric Company d/b/a National Grid shall file with the Public Utilities Commission a confidential copy of the periodic reports required by the Division of Public Utilities and Carriers related to the vegetation management agreement.

5. The Narragansett Electric Company d/b/a National Grid shall follow the Division of Public Utilities and Carriers' recommendations that were filed on February 16, 2017.

6. The Narragansett Electric Company d/b/a National Grid shall consider distributed generation resources as part of its long-range planning studies.

7. Commencing with the Quarter Three periodic report, The Narragansett Electric Company d/b/a National Grid shall include an explanation of all new technologies the Company is exploring to assist in distribution system planning, particularly as they to the integration of distributed energy resources or provide additional visibility on the distribution grid.

8. 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, 2017 PURSUANT TO A BENCH DECISION ON MARCH 9, 2017. WRITTEN ORDER ISSUED NOVEMBER 14, 2017.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

*Herbert F. DeSimone, Jr., Commissioner

Marion S. Gold, Commissioner

*Commissioner DeSimone concurs with the decision but is unavailable for signature.

Notice of Right of Appeal: Pursuant to R.I. Gen. Laws § 39-5-1, any person aggrieved by a decision or order of the PUC 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.