STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: NATIONAL GRID PROPOSED FY 2016 ELECTRIC	:	DOCKET NO. 4539
INFRASTRUCTURE, SAFETY AND RELIABILITY	:	
PLAN PURSUANT TO R.I. GEN. LAWS §39-1-27.7.1	:	

REPORT AND ORDER

I. Filing & Motion to Intervene

On December 23, 2014, 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 2016.[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 Commission's review.[2]

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[1] On May 20, 2010, the Rhode Island General Assembly enacted R.I. Gen. Laws § 39-1-27.7.1 which 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 2016 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/4539page.html.

[2] Filing Letter, 1 (Dec. 20, 2013).

On February 10, 2015, Wind Energy Development, LLC (WED) filed a Motion to Intervene and Objection to the Electric ISR Plan. WED argued that, as a developer of renewable energy, its interests are directly affected and not adequately represented by another party in the docket and that its involvement is in the public interest.[3] WED also filed an objection to the ISR Plan, arguing that the ISR Plan should include planning and implementation of capacity upgrades to facilitate the integration of renewable energy. In its objection, WED noted that 63% of the Electric ISR capital budget is for system capacity and performance to meet growth in the system, but there is no target to support growth of distributed generation on the electric distribution system. WED argued that its interest is in planning for distributed generation in order to reduce the cost of interconnections for renewable energy developers where the renewable energy developers are responsible for system modifications required to allow for safe, reliable parallel operation of the distributed generation facility with National Grid's electric power system, but not general upgrades to the system that would have been necessary anyway.[4]

National Grid filed an objection and supporting memorandum to WED's Motion to Intervene, arguing that WED does not have a right of intervention in the instant matter. According to National Grid, WED's stated interest emanated from the cost of interconnection for ten wind turbines, and is not relevant to the ISR proceeding. Furthermore, the Company argued that it is beyond the scope of the Electric ISR Plan which is concerned with the safety and reliability of providing electric service to all of National Grid's customers. The interconnection standards and costs are set forth in a tariff previously approved by the PUC. Furthermore, according to National Grid, WED is pursuing its

[3] Wind Energy Development Motion to Intervene at 1-2.
[4] Wind Energy Development objection at 1-5.

interests in separate proceedings before the PUC. Additionally, National Grid pointed out that WED will not be bound by a decision in the instant proceeding because it will not be required by the Order to take any action. Finally, National Grid asserted that the Division is the appropriate party to represent the interests of all ratepayers, including WED.[5]

The Division also filed an objection to WED's Motion to Intervene, arguing that WED does not have standing to intervene in the instant matter. According to the Division, WED will suffer no actual or threatened legal injury as a result of the PUC's decision in the instant matter. Thus, the Division asserted that the PUC could deny intervention for lack of standing. However, the Division also indicated that WED does not meet the criteria for intervention set forth in the PUC's procedural rules. WED has no statutory right of intervention. The Division argued that WED does not possess a real interest in the pending matter, but seeks "to transfer its duly-tariffed financial responsibility to pay for interconnection costs onto ratepayers."[6] Next, the Division maintained that it has ample expertise to assess whether interconnection costs for renewable energy should be appropriately included in the Electric ISR budget. Finally, the Division posited that WED's intervention is not in the public interest because the PUC could arrive at the same result without WED's participation in the instant docket, noting that WED's goals, while laudable public policy goals, are not relevant to the merits of the matter.[7]

II. National Grid's Filing

In support of the Electric ISR Plan, National Grid submitted the pre-filed 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

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[5] National Grid's Memorandum in support of its objection to WED's Motion to Intervene, 4-7.
[6] Division's Memorandum of in support of its objection to WED's Motion to Intervene, 4.
[7] *Id*. at 4-8.

support of the development of the revenue requirement and to explain the reconciliation process, National Grid submitted the pre-filed direct testimony of its employee Amy S. Tabor, Senior Analyst of New England Revenue Requirements. In support of the new tariffs and to explain the calculation of the factors and to provide customer bill impacts, National Grid submitted the pre-filed direct testimony of its employee, Jeanne A. Lloyd, Principal Program Manager in Electric Pricing.

A. ELECTRIC ISR PLAN

The plan witnesses indicated that the proposed Electric ISR Plan covers three budget categories for the fiscal year ending March 31, 2016: capital spending on infrastructure projects, operation and maintenance expenses (O&M) for vegetation management, and O&M expenses for an inspection and maintenance (I&M) program.[8] 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."[9]

The proposed capital spending plan for FY 2016 is $73.3 million.[10] According to the plan witnesses, the Electric ISR Plan addresses the capital investment needed for five specific purposes: (1) to meet state and federal regulatory requirements applicable to the electric system (Statutory/Regulatory); (2) to repair failed or damaged equipment (Damage Failure); (3) to address load growth/migration (System Capacity and Performance); (4) to maintain reliable service (System Capacity and Performance); and (5) to sustain asset viability through targeted investments driven primarily by condition (Asset Condition).[11] Of

[8] Pre-Filed Test. of James H. Patterson and Ryan A. Moe, 5.
[9] *Id*.
[10] *Id*. at 6.
[11] *Id*. at 7.

these, the Company considers Statutory/Regulatory and Damage Failure to be non-discretionary "in terms of scope and timing" and "subject to necessary and unavoidable deviations."[12] These items, totaling $36,824,000, account for 37% of the proposed capital outlays in FY 2016.[13]

The remaining - System Capacity and Performance, Asset Condition, and Non-Infrastructure projects - are meant to reduce the degradation of the service life of equipment, to allow for more flexibility in the system for purposes of meeting various contingencies such as load growth and migration, and to address poor condition of aged assets.[14] These items comprise the other 63% of the FY 2015 budget. Specifically, the System Capacity costs of $22,148,000 make up 30%, Asset Condition costs of $24,053,000 make up 33%, and Non-Infrastructure spending of $275,000 makes up the remaining 1%.[15]

The Electric ISR Plan also includes the proposed FY 2016 spending levels for the Company's Vegetation Management Program of approximately $8.9 million. Finally, the I&M spending includes capital amounts already accounted for above plus $3.3 million for O&M costs related to the I&M program. The Company agreed to provide the PUC with quarterly reports on the progress of executing the ISR Plan and an annual report at the time the Company files its annual reconciliation. Additionally, the Company and Division had agreed that if circumstances require, National Grid will be allowed reasonable deviations from the plan, with explanation of significant deviations to be included in its quarterly and year-end reports.[16]

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[12] *Id*. at 8-9.
[13] *Id*. at 8.
[14] *Id*. at 9.
[15] *Id*. at 8-11.
[16] *Id*. at 11-12.

B. SUMMARY OF THE PROPOSED FY 2016 ELECTRIC ISR PLAN

The Capital Plan budget is proposed at $73,300,000.[17] The budget for capital improvements is slightly more than 11% higher than the Company's FY 2015 budget for the same category.[18] Brief summaries of the capital and non-capital categories follow.

1. Statutory/Regulatory ($15,647,000)

The Statutory/Regulatory category is considered "non-discretionary" in that the spending is required to meet regulatory obligations or to comply with various statutes or mandates. The scope and timing is primarily defined by situations external to the Company. Almost half of the budget (49%) is expected to be used to establish electric delivery service to customers. The budget also includes a 26% increase in spending for public projects over the FY 2015 budget to include relocating or adding Company assets due to road or bridge work, moving of assets such as poles to accommodate customer requests, construction requested by other utilities, public authorities, municipalities, and RIDOT. In FY 2016, $1.6 million is allocated for public requirement projects which are required on short notice. The allocation is based on prior years' experience. This budget item also includes $154,000 to facilitate third-party attachments National Grid needs to complete that is not reimbursable in order to address non-conformance with current standards. This budget item is net of contributions in aid of construction (CIAC). In FY 2016, the budget includes $600,000 to

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[17] *Id*. at 8. According to National Grid, its Calendar Year 2013 performance represents an improving trend over the past several years with major event days excluded. According to the Company, continued investment in capital spending, vegetation management, and inspection and maintenance will contribute to continued reliability. Electric ISR Plan, § 2 at 1-5.

[18] Electric ISR Plan, § 2 at 7.

perform upgrades on the Wakefield substation to accommodate the Block Island Transmission System required by R.I. Gen. Laws § 39-26.1-7. [19]

2. Damage/Failure ($11,177,000)

The Damage/Failure category is "to replace equipment that unexpectedly fails or becomes damaged."[20] These costs are considered non-discretionary and include small failures, specific failures in excess of $100,000 based on recent trends, and major storms. The latter two categories allow the Company to continue with its planned work in the capital program while addressing the unexpected failures. The Company has budgeted approximately 14% more than was budgeted in FY 2015, but 28% less than the actual costs incurred in this category in FY 2014. A portion of this budget item is designed to cover assets designated as needing immediate repairs which are identified through the inspection and maintenance (I&M) program.[21]

3. Asset Condition ($24,053,000)

The Asset Condition budget item is for replacement of assets to maintain reliability performance. The FY 2016 budget is approximately 23% higher than FY 2015, driven primarily by the South Street asset replacement project, a lower level of negative schedule reserves, and increased levels of blanket asset replacement projects. This budget item includes the underground residential development and underground commercial development cable strategies which either fix or replace cable that has had at least three failures in the last three years. The majority of this portion of the budget will be targeted to replacement of assets in neighborhoods in Cumberland and Smithfield. The Company also has an underground cable strategy to replace primary underground cable that has

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[19] Electric ISR Plan, § 2 at 11-12, 18-20.
[20] Electric ISR Plan, § 2 at 20.
[21] Electric ISR Plan, Section 2 at 12-13, 20-21.

experienced poor performance. This budget item also includes replacement of substation batteries over 20 years old or that do not meet current operating requirements, replacement or retirement of metalclad switchgear that has operating issues or is of the same type as others with operating issues, replacement of obsolete circuit breakers, replacement of relays with operational issues as part of a six-year plan, proactive replacement of substation transformers that have a high likelihood of failure, continuation of the network arc flash program and flood mitigation projects. This budget item specifically includes a project at the Southeast substation in Pawtucket which, once the metalclad switchgear is retired, will allow the Company to address capacity and operational issues related to that substation and the Pawtucket No. 1 substation. The next is replacement of the South Street substation with a budget in this multi-year project of $4.6 million in FY 2016. Finally, the Westerly flood restoration project has again been redesigned with work to be done on the Chase Hill substation and the Westerly substation whereas the prior proposal had an expansion of the Hopkinton substation and retirement of the Westerly substation. The FY 2016 cost is budgeted at $650,000.[22]

4. Non-Infrastructure ($275,000)

The Non-Infrastructure category is for capital expenditures that do not fit into one of the other categories, such as general and telecommunications equipment which are necessary to run the electric system.[23]

5. System Capacity & Performance ($22,148,000)

Load relief comprises 87% of the System Capacity & Performance budget item related to eight substation projects. The remainder of the budget is used for the distribution

[22] Electric ISR Plan, § 2 at 13-14, 21-32.
[23] Electric ISR Plan, § 2 at 14.

line transformer strategy to mitigate unplanned outage/failure risks due to overloads and asset condition of distribution line transformers, a distribution load relief blanket and distribution reliability blanket for work under $100,000, minor storm hardening projects to target specific areas with poor performance in minor storm events, expansion of the substation EMS/RTU SCADA additions program to improve reliability performance and increase operational effectiveness, targeting 16 substations. Finally, this budget item and to complete the advanced volt/var management scheme program which is currently in the preliminary engineering stage. This portion of the budget includes distribution substation, line communications and information systems necessary to complete the project.[24]

6. Vegetation Management ($8,884,000 – Non-Capital)

The Vegetation Management budget includes cycle pruning ($5,414,000) which is the continuation of four year cycle; enhanced hazard tree mitigation work ($1,000,000) to identify and remove dying or structurally weakened trees along the three phase sections of distribution circuits; sub-transmission (off & on road) ($220,000); and police/flagger detail ($750,000) related to cycle pruning and hazard tree work. The police/flagger detail costs for the most recent three fiscal years were: $461,000 in 2012, 766,000 in 2013, $769,000 in 2014, $650,000 (estimated) in 2015. This category also has a general line item called all other activities which includes trimming associated with interim/spot areas, customer requests, emergency response, and worst performing feeders ($1,500,000).[25]

7. Inspection and Maintenance Plan ($3,333,000 – Non-Capital)

The goal of the Inspection and Maintenance (I&M) program is to inspect and repair all feeders on a ten year cycle. This budget item includes operation and maintenance

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[24] Electric ISR Plan, § 2 at 9, 32-44.
[25] Electric ISR Plan, § 3 at 2-12.

(O&M) expenses for overhead distribution feeders and sub-transmission lines, contact voltage testing, and volt/var costs. The costs included in I&M are related to operating expenses related to the capital expenditures, repair related costs, and inspections related costs.

The overhead inspection and maintenance includes distribution and sub-transmission repairs. By the end of FY 2015, National Grid expects 20% of the overhead distribution feeders will have been repaired under the I&M program. The sub-transmission feeders will be subject to inspections, engineering, and limited repairs. The underground inspection and maintenance is comprised of inspection that continues to be performed in the normal course of work, with repairs commencing in FY 2016. The contact voltage testing includes overhead manual, underground manual, street lighting manual, and mobile contact voltage. Overhead manual testing will be performed as part of cycle inspections, underground manual testing will continue on a five-year cycle, street lighting manual testing will continue on a three-year schedule, and mobile contact voltage testing will test 100% of the designated contact voltage risk areas. Finally, this budget item includes O&M related to the volt/var program.[26]

8. REVENUE REQUIREMENT – REVISED

On March 10, 2015, National Grid filed a revised revenue requirement to incorporate the results of a change to federal tax law, signed by President Obama on December 19, 2014, decreasing the FY 2016 Electric ISR Plan revenue requirement by $664,617. However, this was offset by a proposed increase of $760,233 resulting from the "discover[y] that the Electric ISR Plan revenue requirement did not properly reflect an offset to accumulated deferred taxes related to tax net operating losses (NOL) generated by the

[26] Electric ISR Plan, § 4 at 2-5.

Company since its FY ending March 31, 2012."[27] National Grid stated that the Company participates in a consolidated National Grid tax return with affiliated companies and that the Company did not reflect in the FY 2016 Electric ISR Plan revenue requirement, the capitalization of certain expenses, properly capitalized from a ratemaking standpoint, but that had been expensed for purposes of the Internal Revenue Service.[28] The overall result was in increase of $95,616 over what had originally been filed.

Ms. Tabor explained that the revenue requirement of the FY 2016 Electric ISR Plan includes (1) an O&M expense related to vegetation management and the Company's I&M Program as well as (2) the Company's capital investment in electric utility infrastructure.[29] The forecasted FY 2016 revenue requirement of $21,201,792 is an incremental increase of $8,951,484 from the FY 2015 Electric ISR Plan revenue requirement of $12,250,309. The amount related to O&M expenses was $12,053,251. Of that amount, $8,884,000 was for Vegetation Management and $3,333,000 was related to Inspection and Maintenance O&M expenses. This was offset by a reduction of $163,749 to reflect the contact voltage expenses included in base rates.[30]

9. National Grid's Supplemental Testimony on Tax Issue

On March 13, 2015, in support of the revised revenue requirement, National Grid submitted Pre-filed testimony of Michael D. Laflamme, Vice President, Regulation and Pricing Officer and William R. Richer, Director of Revenue Requirements – Rhode Island. After explaining the concept of bonus depreciation, the witnesses explained that because the tax law was signed after the filing of the FY 2016 Electric ISR Plan, it was necessary to file

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[27] National Grid Filing Letter, 1-2 (Mar. 10, 2015).
[28] *Id*.
[29] Pre-Filed Test. of Amy S. Tabor, 2.
[30] Electric ISR Plan, Section 5: Attachment 1, Revised at 1.

a revision to incorporate the effect of the tax change. Next the witnesses explained that an NOL is generated when the Company has tax deductions on its income tax returns that exceed its taxable income. Thus, the Company is not allowed to take full advantage of bonus depreciation until such time as there is taxable income against which to apply the deduction. NOLs represent a benefit that customers will receive at the time when the Company can apply the NOLs against taxable income in the future.[31]

According to the witnesses, after determining that NOLs would be generated as a result of the 2014 tax change, the Tax Department determined that NOLs had been generated in FY 2012, FY 2013 and FY 2014. The result was that the ISR rate base had been reduced the revenue requirement lowered. Therefore, "all previously filed Electric and Gas ISR revenue requirement calculations since FY 2012 have provided customers with too much of a cash benefit associated with these tax deductions by not reducing ISR related deferred taxes by the amount of ISR investment related to NOLs."[32]

The witnesses explained that the FY 2016 cumulative revenue requirement impact is $0.8 million in the Electric ISR until the Company can apply the NOLs to taxable income. Deferral of recovery would increase the need for additional recovery in the future plus carrying costs. While the revised filing does not address the cumulative revenue requirement for prior years, the witnesses do expect to address the FY 2015 NOLs in the reconciliation filing for the FY 2015 Electric ISR Plan. The witnesses also suggested the Company may seek to recover costs related to FY 2012, FY 2013 and FY 2014 in the FY 2015 reconciliation filing.[33]

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[31] National Grid Test. of Michael Laflamme & William Richer, 5-9.
[32] *Id*. at 10.
[33] *Id*. at 10-12.

10. DEVELOPMENT OF ISR FACTOR

Ms. Lloyd 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 activities. To design the CapEx factors to develop the incremental capital investment, following Commission review of a cumulative revenue requirement, National Grid will apply a rate base allocator based on the most recently approved cost of service study. Similarly, the design of the O&M Mechanism is 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 per the most recent cost of service study. Within each rate class, National Grid calculates a per unit charge based on kWh usage for non-demand classes and on a kW basis for demand classes.[34]

Each year, by August 1, the Company proposes CapEx Reconciling Factors and an O&M reconciling factor to become effective on October 1 for the following twelve-month period. The reconciliation will compare the actual cumulative revenue requirement to actual billed revenue generated from the CapEx Factors and any over- or under-recovery will be refunded to or collected from customers through the CapEx 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 and any over- or under-collection

[34] Pre-Filed Test. of Jeanne Lloyd, 3-7; Section 6: Rate Design, Revised. G-02 and G-32/B-32 customers whose charges include both demand and usage, the CapEx 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." Pre-Filed Test. of Jeanne Lloyd, 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. Pre-Filed Test. of Jeanne Lloyd, 9-12.

of actual expense will be refunded to or collected from customers through a uniform per kWh charge applicable to all rate classes.[35]

Ms. Lloyd explained that the CapEx Factors are designed to collect the cumulative revenue requirement of $9,148,541 attributable to incremental capital investments through the end of FY 2016. The cumulative revenue requirement is allocated to the various rate classes based on the total rate base allocator that was included in the Commission-approved Amended Settlement Agreement filed in Docket No. 4323.[36] The O&M Factors are designed to collect the $12,053,251 in forecasted FY 2016 I&M and vegetation management O&M activities. The monthly rate increase on the bill of a typical residential customer using 500 kWh per month would be $0.79 per month.[37]

III. Division's Filing

On March 3, 2015 and March 20, 2015, the Division submitted the pre-filed testimony of its consultants, Gregory L. Booth, P.E. and David J. Effron, respectively. Mr. Booth indicated that the Division supports the FY 2016 Electric ISR Plan as filed. Mr. Booth indicated in his memorandum that the filed plan represents a $3.9 million reduction from that which was originally presented to the Division in the Fall of 2014. Mr. Booth supported the FY 2016 Electric ISR Plan as balancing the need for safety and reliability with the efficient benefit/cost considerations. However, Mr. Booth devoted a substantial portion of his commentary to the value of a comprehensive System Capacity Load Study and Long Range Plan, which he recommended and the PUC adopted in 2014. As the study is not complete, Mr. Booth indicated that support of several of the new projects in the 2016

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[35] *Id*. at 5, 7-8.
[36] *Id*. at 8; Section 5: Attachment 1, Revised. *See* Order Nos. 20943 (issued January 31, 2013), 21011 (issued April 1, 2013), and 21054 (issued May 29, 2013).
[37] Pre-Filed Test. of Jeanne Lloyd, 9, 11; Section 7: Bill Impacts, Revised, 1.

Electric ISR Plan is conditioned upon completion of the study. He also expressed concern with the level of detail included in National Grid's budgets for capital projects. Mr. Booth expressed frustration with the status of negotiations with Verizon related to vegetation management cost sharing.[38] Accordingly, Mr. Booth made ten recommendations for the Commission to consider:

(1) National Grid should be required to accelerate development of a System Capacity Load Study and develop a 10-year Long Range Plan as part of the FY 2018 Electric ISR Plan.
(2) National Grid should be required to revisit the scope and budget of the South street substation project in the Asset Replacement category once the Providence short term study and preliminary engineering are complete and provide the results to the Division not later than August 31, 2015. This should include detailed design, identification of risks and mitigation strategies, and a refined budget for further evaluation.
(3) National Grid should be required to limit FU 2016 expenses to preliminary engineering for the Southeast Substation project and provide a detailed project scope, timeline and budget for further evaluation and provide same to the Division no later than August 31, 2015.
(4) National Grid should be required to limit FY 2016 expenses to system capacity studies and preliminary engineering for the East Bay Study and Jepson Substation projects in the System Capacity and Performance category until a 10-year Long Range Plan is complete, at which time the projects should be evaluated against the results of such plan.
(5) National Grid should be required to evaluate cost effective alternatives for the Quonset Point project in the System Capacity and Performance category, and demonstrate that proposed solutions align with the industrial expansion timing and capacity needs.
(6) National Grid should continue to be required to complete 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 and submit it no later than August 31, 2015.
(7) National Grid should be required to submit an evaluation of future proposed Asset Condition projects as compared to the Long Range Plan no later than August 31, 2015.
(8) National Grid should be required to continue to submit its detailed substation capacity expansion plans and load projections, and include an evaluation of

[38] Pre-filed Test. of Gregory L. Booth, P.E., 1-11; Exh. GLB-1 (Report), 7-42. On March 10, 2015, Verizon filed with the PUC a letter outlining an agreement reached between the Company and the Division, including an action plan to address cost sharing of tree trimming benefitting Verizon. Letter from Atty. Webster to Luly Massaro (Mar. 10, 2015).

proposed projects against the Company's Long Range Plan no later than August 31, 2015.

(9) National Grid should be required to continue to submit a cost-benefit analysis on Vegetation Management cycle pruning and EHTM no later than August 31, 2015.

(10) National Grid should be required to continue submitting it Metal-Clad Switchgear replacement program cost-benefit analysis to the Division no later than August 31, 2015.[39]

Mr. Effron discussed inconsistencies and discrepancies he had found during the Division's initial review of National Grid's proposed FY 2016 Electric ISR Plan and noted that they had been addressed in the December 23, 2014 filing with the PUC. He also addressed the recalculation of the ISR revenue requirement for FY 2016 resulting from the Tax Increase Prevention Act of 2014, affecting bonus depreciation. Finally, Mr. Effron discussed the NOL issue raised by National Grid. He explained that because the calculation of the accumulated deferred income taxes reflected tax benefits that the Company could not take, and these tax benefits had been deducted from plant in service in the determination of rate base, it had the effect of understating the rate base and revenue requirement. Thus, National Grid had revised its FY 2016 revenue requirement to reflect the NOL. Mr. Effron stated that he had reviewed the revised revenue requirement and "agree[d] that the Company's revisions and the treatment of the NOLS are appropriate for the purpose of determining the Fiscal Year 2016 revenue requirement."[40]

IV. Hearing

On March 17, 2015, the Commission conducted a Hearing at its Offices at 89 Jefferson Boulevard, Warwick, Rhode Island for the purpose of discussing and considering the Electric ISR Plan for FY 2016.[41] National Grid presented Mr. Patterson, Mr. Moe, Ms.

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[39] Pre-file Test. of Gregory L. Booth, P.E., 11-14; Exh. GLB-1 (Report), 42-46.

[40] Memorandum of David Effron, 1-2 (Mar. 20, 2015).

[41] Raquel Webster, Esq. and Celia O'Brien, Esq. appeared on behalf of National Grid. Leo Wold, Esq, Assistant Attorney General, represented the Division and Cynthia Wilson-Frias, Esq., represented the PUC.

Lloyd, Ms. Tabor, Mr. Laflamme, and Mr. Richer in support of the FY 2016 Electric ISR Plan. Mr. Patterson explained that National Grid agreed with the substance of each of Mr. Booth's recommendations but for the accelerated completion date of the long-range studies.[42]

Mr. Patterson explained that the long-range studies have been prioritized by geographic load centers. In order to prioritize the areas, the Company considered the load for the year and how the substations and the electrical system interconnects. In addition, localized forward-looking economics is a factor. For example, National Grid considers whether there is business development and expected growth in customer base.[43] The long-range studies will allow National Grid to identify all of the problems in an area and address them comprehensively by determining whether there is a single solution that can solve multiple problems rather than focusing on each issue alone. The purpose is to ultimately reduce the amount of money spent on resolving all of the issues.[44] Mr. Patterson opined that the long-range studies could allow the Company to become more proactive rather than reactive in certain budget areas.[45]

There are currently limitations in the planning process, particularly in the coordination of customer-driven distributed generation projects with the standard planning process. According to Mr. Roughan, one of the challenges is that the standard planning process is an annual review of how all circuits react to peak loading of the system, whereas the processing of distributed generation applications is driven by customer requests and have a specific timeline to follow. Additionally, within the planning process, the Company has to

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[42] Tr. at 14-17 (Mar. 17, 2015).
[43] *Id*. at 68-70.
[44] *Id*. at 96-97.
[45] *Id*. at 110.

assess the reliability of various solutions.[46] To date, according to Mr. Roughan, it has been difficult to assess the reliability of a customer-sided asset "to meet the peak loads day after day, week after week, summer after summer for multiple years."[47] Mr. Patterson added, however, that when the Company is aware of a customer-sided project or, alternatively, of an expected increase in load due to customer expansion, it assesses the impact of that project on planned system upgrades. For example, he noted that T.F. Green Airport is expanding and that expansion will overlay a portion of the distribution facilities being upgraded by National Grid, including a nearby substation. Rather than repeating work, National Grid was able to defer apportion of the upgrade to incorporate the design and expansion of the airport project.[48] Also, referencing a distributed generation project in Quonset, Mr. Patterson explained that the Company evaluated whether or not that facility can be depended on to assist in the overall load in a peak condition. If so, such information would be included in the solution development process for known problems existing in Quonset.[49]

Currently, National Grid does not have a system plan that would identify areas that would benefit from distributed generation. Some states have created renewable energy zones and Mr. Patterson agreed that if that was something adopted by the PUC, it could be incorporated into the ISR planning process.[50] Additionally, the ten-year plans, as tool to allow for a more comprehensive review of the planning process, will allow the Company to be used as a guide where some targeted energy efficiency may be done or where a system reliability project may be more appropriate.[51] However, Mr. Roughan reiterated that one of

[46] *Id*. at 71-76.
[47] *Id*. at 75.
[48] *Id*. at 88-89.
[49] *Id*. at 103.
[50] *Id*. at 78, 86, 93, 149, 159.
[51] *Id*. at 101.

the biggest challenges is assessing and enforcing the reliability attributes of a customer-owned asset on the system at times of peak demand.[52]

Mr. Roughan pointed out that the system reliability projects, such as the Tiverton/Little Compton pilot, is reviewed and funded through a separate program and recovery mechanism.[53] Mr. Roughan and Mr. Patterson both noted that there are several different legislative mandates and that they compete for planning resources which are conducted by many of the same personnel.[54] Mr. Roughan acknowledged the PUC's challenge in ensuring the setting of just and reasonable rates across programs, not just within each program, and stated that if there is a collaborative effort to modify the expectations of the ISR plan, the ISR plan could meet the need of providing the PUC with information that spending in one program versus another is moving the funds rather than doubling them.[55]

Turning to contributions in aid of construction and the ISR planning process, Mr. Patterson stated that where a customer expansion requires an upgrade to the distribution system, National Grid projects the additional load and revenue that will be required. That expected additional revenue is weighed against the total project cost and would reduce the contribution in aid of construction that would have to be paid by the customer. He explained that it becomes a little more complicated when the Company had already identified a system upgrade that would be needed in the area absent the additional load. The costs required absent the customer expansion would not be passed on to the customer.

[52] *Id*. at 167-69.
[53] *Id*. at 97-101
[54] *Id*. at 75, 161-62.
[55] *Id*. at 165-66.

Additionally, in this scenario, if the expense is two times the annual revenue expected from the customer, it is passed through the ISR without a contribution in aid of construction.[56]

Finally, Mr. Laflamme summarized the status of a Massachusetts case between National Grid and Verizon regarding cost responsibility for various tree trimming activities. He noted that the two companies are currently in negotiations about many operating issues. He stated that Verizon has represented that tree trimming is not as important to telecommunications as to electric as telecommunications will often operate, even if on the ground. Mr. Moe testified that Verizon and National Grid had met to discuss National Grid's hazard tree program and conducted a field review after finding interest by Verizon in the benefits it may receive from that program.[57]

The Division presented Mr. Booth for cross examination. Mr. Booth testified that it is "unusual for a utility not to have a comprehensive system model short and long-range [studies]."[58] According to Mr. Booth, a long-range plan provides a road map to where the entire system expansion is headed. It also provides a framework for upgrades and additions to the distribution system. A utility requires:

> a long-range plan that shows how to best optimize the existing capacity and infrastructure and add that capacity and infrastructure in a most economical way across your whole system and integrate that with your entire resource plan, whether that be distributed generation, volt var programs, smart grid programs, all the latest technologies to optimize utilization of your capacity.[59]

Planning on a year to year basis will, according to Mr. Booth, results in a greater cost and capital investment with waste.[60]

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[56] *Id*. at 114-15.
[57] *Id*. at 206-13.
[58] *Id*. at 220.
[59] *Id*. at 221-22.
[60] *Id*. at 222.

These long-range studies are a component of the system resource plan. He opined that the long-range studies would be an excellent resource for planning for distributed generation, system reliability or energy efficiency. However, currently, the long-range studies he has promoted have not been designed with those goals at this time.[61] He explained that the long-range studies will be very detailed and difficult to be used by anyone outside of the Company for determining how they may work with the distributed generation program. He thought "[i]t would probably be more appropriate for the company to overlay" an analysis with a summary document and summary maps to determine how the DG program fits within the ISR planning process.[62] He recommended a collaborative method to develop a good mechanism by which to communicate the information sought by the PUC and distributed generation customers.[63]

Next, Mr. Booth commented that National Grid's annual budgets should be tighter with a smaller margin for error. This would require more detailed engineering studies, particularly for the larger projects. A plus or minus 25% budget estimate is too broad for him. Additionally, according to Mr. Booth, the contingency and risk items should be better defined.[64] He stated that there has been a "tremendous amount of budget creep in part because the budgets weren't based on more comprehensive engineering."[65] He noted that the longer time a project takes, the more resources it requires, increasing the costs. This is something National Grid has agreed to work on.[66]

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[61] *Id*. at 224.
[62] *Id*. at 227. With regard to distributed generation, Mr. Booth echoed some of the sentiments of the Company, noting that distribution utilities currently face a dilemma of how to "firm" the reliability of variable distributed generation resources. *Id*. at 224-25.
[63] *Id*. at 228.
[64] *Id*. at 236.
[65] *Id*. at 237.
[66] *Id*. at 237-38.

Finally, Mr. Booth expressed continued frustration regarding the lack of contributions to the vegetation management budget from Verizon. He noted that any third-party pole attacher pays rates set by the Federal Communications Commission and that those rates include a component of vegetation management expense. He maintained that it is unfair for Verizon not to participate in those costs.[67] Despite this, he supported the agreement entered into between Verizon and the Division to address future actions toward seeking costs recovery and did not believe a downward adjustment to the vegetation management budget was necessary at this time.[68]

V. Commission Findings

A. WED's Motion to Intervene and Objection to Electric ISR Plan

At an Open Meeting held on February 25, 2015, the PUC denied WED's Motion to Intervene and struck the objection. After review of the record, the PUC found that WED's concerns are outside the scope of the ISR Plan proceeding in that WED attempts to use the ISR Plan to shift responsibility of interconnection costs from developers to the ratepayers. The PUC summarized Section 1.13(b) of the PUC Rules noting that WED does not have a right to intervene conferred by statute, that the Division can address the concerns articulated by WED, that WED will not be bound by any action that the PUC may take, and that WED's participation cannot be said to be in the public interest. The PUC noted that WED could present public comments in this matter.[69]

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[67] *Id*. at 239-40.
[68] *Id*. at 241-43.
[69] WED's public comments were referenced by the PUC at the hearing during which the PUC sought information from National Grid related to those comments. *See* Tr. at 77-86, discussing the relationship between ISR as a reliability plan and distributed generation's potential effects on reliability as part of the planning process.

B. Electric ISR Plan

At an Open Meeting held on March 31, 2015, the PUC approved the FY 2016 Electric ISR Plan finding that it complies with the statutory mandates. The PUC approved a revenue requirement of $21,201,792 which results in an incremental fiscal year rate adjustment of $8,951,484. It also approved the proposed rates for each rate class. The PUC also considered the Company's supplemental filing that incorporated the impact of the extension of federal bonus tax depreciation rules, as well as the impact of the Company's failure to properly reflect an offset to accumulated deferred taxes related to tax net operating losses generated by the Company since its FY ending March 31, 2012 into its revenue requirement. The supplemental filing represented that the effect of these two events caused the Company's FY 2016 Electric ISR Plan revenue requirement to increase by $95,616. The PUC finds the Company's explanation of the NOL issue, both the pre-filed and oral testimony of Messrs. Laflamme and Richer, informative. Because the Company corrected its FY 2016 Electric ISR Plan revenue requirement prior to the PUC's decision, the revised revenue requirement is approved for FY 2016 only. The PUC cautions that this approval of the $95,616 increase resulting from the NOLs in no way addresses the previously approved revenue requirements related to the Electric ISR Plans from prior years.

The PUC also approves the agreement between National Grid and the Division relating to outstanding issues between the Company and Verizon and requires National Grid to file with the PUC a confidential copy of the periodic reports required by the Division. National Grid needs to pursue this matter as it did in Massachusetts. The PUC means to be crystal clear that National Grid should take all necessary steps to collect a reasonable contribution from Verizon. Verizon is still a public utility in Rhode Island despite the level of the PUC's current regulatory oversight and still has a mandate to contribute to the reliability of the utility system, just like other public utilities and third party pole attachers. The impact on a standard residential customer using 500 kWh per month is an increase of $0.79 per month.

One issue that is still of great concern to the PUC is the cost of police details, particularly those included in the vegetation management budget. The PUC understands from the testimony in this, and several other dockets, that the utilities are largely at the mercy of the municipalities. Projected traffic control costs are in excess of 8% of the overall vegetation management budget, with one town demanding 19% of the police expense where the tree trimming in that town was only 8% of the overall trimming. Testimony was that this town demands police details on cul-de-sacs as well as main roads. According to National Grid, the utility must accept the cost or stop the work, an action that may result in reduced reliability in the area.[70] Additionally, it is still unclear to this PUC why the electric police detail costs seem to be so high compared to those on the natural gas side of the business. Finally, just because there is a cost tracker which is fully reconciling, National Grid is operating in 38 of Rhode Island's municipalities and needs to be aggressive in education and outreach. Municipalities need to be aware that higher police detail costs within a budget means less work on the activities related to reliability and modernization of assets. The PUC will be looking for more action by National Grid to provide reasonable expectations to the municipalities.[71]

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[70] *See* Tr. at 179-95.

[71] The PUC asked National Grid and the Division to brief "whether R.I. Gen. Laws § 39-1-30 applies to municipal policies or decision made by municipalities and/or their police chiefs regarding the necessity and cost of police details." Both National Grid and the Division concluded that it would and thus, the PUC would have jurisdiction over challenges brought to it by the utility regarding a police chief's decision or municipal police detail policy.

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.

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. The PUC encourages National Grid to use its very best efforts to complete those ahead of schedule and more in line with Mr. Booth's recommendation.

Accordingly, it is hereby

(22174) ORDERED:

1. The Narragansett Electric Company d/b/a National Grid's Revised Electric ISR Plan filed on December 23, 2014, as amended on March 10, 2015 and associated compliance tariffs are hereby approved for usage on and after April 1, 2015.
2. The Narragansett Electric Company d/b/a National Grid shall provide, as part of its FY 2017 filing, more detail to support the purported need for the investment, 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 2017 filing, a proposal to report in quarterly and annual reconciliations, detail on individual projects where the costs differed from budget by more than 10%, whether the difference resulted from over- or under-spending or timing.
4. The Narragansett Electric Company d/b/a National Grid shall file with the PUC a confidential copy of the periodic reports required by the Division related to the Vegetation Management agreement.
5. The Narragansett Electric Company d/b/a National Grid shall consider distributed generation resources as part of its long-range studies.
6. 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, 2015 PURSUANT TO AN OPEN MEETING DECISION ON MARCH 31, 2015. WRITTEN ORDER ISSUED OCTOBER 21, 2015.

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Paul J. Roberti, Commissioner

Herbert F. DeSimone, 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 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.