STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID – ELECTRIC AND GAS DISTRIBUTION RATE FILING	:	**DOCKET NO. 4770**
IN RE: THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID PROPOSED POWER SECTOR TRANSFORMATION VISION AND IMPLEMENTATION PLAN	:	**DOCKET NO. 4780**

REPORT AND ORDER

I. Procedural History

On November 27, 2017, The Narragansett Electric Company d/b/a National Grid (Company)[1] filed with the Public Utilities Commission (PUC or Commission) a request to change base distribution rates for both electric and gas operations (rate case). On the same date, the Company filed a proposed Power Sector Transformation Vision and Implementation Plan (PST filing). After review of the filings, the PUC docketed the rate case and PST filings separately and on December 20, 2017, suspended the effective date of each for up to eight months or until September 1, 2018.[2] Two separate procedural schedules were set for the filings.

In its rate case filing, the Company originally requested an increase in its revenue requirements of $41,294,907 for Narragansett Electric and $30,322,543 for Narragansett Gas.[3] On

[1] The term Company refers to The Narragansett Electric Company's intrastate electric and gas distribution operations collectively. Where there is a need to refer to the individual electric and gas distribution operations of the Company, the terms Narragansett Electric or Narragansett Gas, respectively, are used. The National Grid USA Service Company is referred to as Service Company. All filings related to these dockets can be accessed on the PUC's website at: http://www.ripuc.ri.gov/eventsactions/docket/4770-Year1.html and http://www.ripuc.ri.gov/eventsactions/docket/4780page.html. The filings are also maintained at the PUC's offices at 89 Jefferson Blvd., Warwick, Rhode Island.
[2] Open Meeting Minutes (Dec. 20, 2017); http://www.ripuc.ri.gov/eventsactions/minutes/122017.pdf.
[3] Melissa Little Test. at 5 (Nov. 27, 2017).

December 22, 2017, the federal government enacted the Tax Cuts and Jobs Act[4] which, among other things, reduced the corporate tax rate from 35% to 21% and affected the calculation of deferred income taxes. As a result of this statutory change and an error in the initial filing, on March 2, 2018, National Grid revised its requested increase to $27,434,395 for Narragansett Electric and $18,408,489 for Narragansett Gas.[5] Subsequently, on May 9, 2018, the Company further reduced its requested increase to $18,877,761 for Narragansett Electric and $15,451,041 for Narragansett Gas.[6]

In its PST filing, the Company sought a finding that its vision was consistent with state law and regulatory policy.[7] It described the contents of the PST filing as investments to present "a strategic opportunity and implementation vehicle through which to modernize the utility business model, deploy advanced meters, enhance distribution system planning, and pursue beneficial electrification."[8] It proposed to file annual investment plans and requested approval of a cost recovery mechanism that would forecast those annual investment costs and include a fully reconciling mechanism after the conclusion of the annual period. Costs would be recovered form electric distribution customers. According to the Company, gas customers would benefit from some of the investments, so the Company proposed to also recover costs from those customers. The Company requested approval of positive-only performance incentives with an associated

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[4] An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (Tax Cuts and Jobs Act), Pub. L. No. 115-97, 131 STAT. 2054 (2017); https://www.govinfo.gov/content/pkg/PLAW-115publ97/html/PLAW-115publ97.htm.
[5] Little Schedule MAL-1-ELEC (REV-1), Schedule MAL-1-GAS (REV-1) (Mar. 2, 2018).
[6] Little Rebuttal Test. at 6-7, Schedule MAL-1-ELEC (REV-2), Schedule MAL-1-GAS (REV-2) (May 9, 2018).
[7] Kayte O'Neill et al. Jt. Test. at 4.
[8] *Id.* at 8.

recovery factor. For FY 2019, the Company requested approval of $2 million for incremental costs for advanced metering functionality design work.[9]

The following parties were granted intervenor status in both matters, unless otherwise noted in the footnotes: the U.S. Department of the Navy and the Federal Executive Agencies (collectively, Navy/FEA); Conservation Law Foundation (CLF); Energy Consumers Alliance of New England, Inc. d/b/a People's Power and Light (PPL);[10] the Sierra Club;[11] the Natural Resources Defense Council (NRDC);[12] Acadia Center (Acadia); the Northeast Clean Energy Council (NECEC); the George Wiley Center (Wiley Center); New Energy Rhode Island (NERI); Wal-Mart Stores East, LP and Sam's East, Inc. (collectively, Wal-Mart); Direct Energy Business, LLC, Direct Energy Services, LLC, and Direct Energy Solar (collectively, Direct Energy)[13]; ChargePoint, Inc. (ChargePoint)[14]; and the National Railroad Passenger Corporation (Amtrak).[15] In addition, the Office of Energy Resources (OER) and the Division of Public Utilities and Carriers (Division) participated under their respective statutory authority and mandates.

On April 6, 2018, the Division and intervenors submitted direct testimony or comments on various portions of the rate case. In addition to challenging parts of the requested revenue increase, the Division challenged the requested funding of a proposed investment into management tools related to the gas distribution system (Gas Business Enablement), requested funding for information services, certain investments categorized as grid modernization, personnel and other

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[9] *Id*. at 4, 93-99.
[10] PPL intervened in Docket No. 4770 individually and in Docket No. 4780 jointly with Sierra Club and NRDC. Subsequently, in 2018, the name was corporate name was changed to Green Energy Alliance of New England.
[11] The Sierra Club intervened in Docket No. 4780 jointly with PPL and NRDC.
[12] NRDC intervened in Docket No. 4780 jointly with PPL and the Sierra Club.
[13] Direct Energy was an intervenor in Docket No. 4780 only.
[14] ChargePoint was an intervenor in Docket No. 4780 only.
[15] Amtrak is an intervenor in Docket No. 4770 only.

operational expenses, the cost of capital and return on equity, depreciation valuation, low income and income-eligible proposals, and the allocated cost of service and rate design for both electric and gas. The testimony on the electric allocated cost of service and rate design was supplemented on April 25, 2018. The Division also addressed the appropriate structure and role of performance incentive mechanisms and the appropriate cost recovery mechanisms for grid modernization activities.[16]

The Navy/FEA witness raised issues relating to rate design and the proposed revenue allocation.[17] Wal-Mart's witness challenged portions of the revenue allocation, rate design, and the return on equity as well as impact of the Tax Cuts and Jobs Act.[18] NERI's witness expressed concerns with the revenue requirement, the magnitude and calculation of the proposed return on equity, the reasonableness of the rate design, the adequacy of forecasting, the appropriateness of the revenue allocation, and the propriety of the design of the streetlighting tariff.[19] Acadia Center's witness raised concerns with the proposed rate design and return on equity.[20] OER submitted comments on the need to align the Company's proposals with the State's policy goals for the future of the power system.[21] The Wiley Center expressed concerns with the Company's low-income discount rate design proposals.[22]

On May 9, 2018, the Company submitted rebuttal testimony in response to the Division and intervenor testimony and comments. Specifically, the Company's witnesses addressed

[16] Tim Woolf Test.; Michael Ballaban and David Effron Jt. Test.; Tina Bennett and Alan Neale Jt. Test.; Gregory Booth Test.; Matthew Kahal Test.; Tim Woolf and Melissa Whited Jt. Test.; Roxie McCullar Test.; Roger Colton Test.; John Athas Test.; Athas Supp. Test.; Bruce Oliver Test.
[17] Ali Al-Jabir Test.
[18] Greg Tillman Test.
[19] Karl Rábago Test.
[20] LeBel Test.
[21] OER Comments.
[22] Wiley Center Comments.

intervenor testimony on return on equity and capital structure, depreciation, electric and gas forecasting, information systems investment, Gas Business Enablement, personnel and operational expense, allocated cost of service, revenue allocation, and rate design for electric and gas, PST policy, grid modernization, and performance incentive mechanisms.

On April 17, 2018 and April 25, 2018, filings were made by the Division and intervenors in response to the PST filing. The Division addressed multi-year rate plans; performance incentive mechanisms; the Company's proposals for the electric vehicles; electric heat; electric storage; Company-owned solar generation; advanced metering functionality; and the benefit-cost analyses.[23] In comments, OER also addressed the performance incentive mechanisms; proposed grid modernization investments; advanced metering functionality; electric vehicle proposals; electric heat proposals; the electric storage initiative; Company-owned solar generation; and the proposed cost recovery mechanism.[24]

The Navy/FEA witness raised issues relating to the cost recovery mechanism, cost allocation and rate design, and performance incentive mechanisms.[25] CLF, jointly with the PPL/Sierra Club/NRDC witness, raised issues related to the advanced metering functionality and electric vehicle proposals.[26] CLF jointly with the PPL/NRDC witness raised issues related to the electric heat proposals.[27] NERI's witness expressed concerns with overall PST policy and vision, the proposed cost recovery mechanisms, the performance incentive mechanisms, and the benefit cost analyses.[28] NECEC and CLF's joint witness raised issues related to the proposed grid

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[23] Gregory Booth Test.; Tim Woolf Test.; Melissa Whited Test.
[24] OER Comments.
[25] Ali Al-Jabir Test.
[26] Douglas Jester Test.
[27] Benjamin Stafford Test.
[28] Karl Rábago Test.

modernization investments, advanced metering functionality, the electric storage initiative, Company-owned solar generation, and income eligible programs.[29] NECEC and CLF's joint witness also raised issues related to performance-based regulation, performance incentive mechanisms, and the proposed cost recovery mechanism.[30] Acadia Center's witness raised concerns with the proposed rate design and return on equity.[31] Direct Energy's witness raised issues related to the proposed grid modernization investments, advanced metering functionality, time-varying rates, and electric vehicle proposals.[32] ChargePoint's witness raised issues with the electric vehicle proposals.[33] No party supported the Company's cost recovery mechanisms for PST investment.

Between the two dockets, over 1,500 data requests were responded to by the Company with the other parties responding to several more. The Commission conducted five technical sessions to review and ask questions on specific proposals in the PST filing. The Commission also convened twelve Open Meetings to discuss the issues raised by the parties throughout the pendency of this case prior to the filing of a Settlement by the parties.

II. Settlement

On June 6, 2018, National Grid filed a comprehensive Settlement Agreement that resolved all issues disputed by the parties in both the rate case and PST filing.[34] The PUC held eleven days of evidentiary hearings from June 12, 2018 through June 28, 2018. During the course of the

[29] Nathan Phelps Test.; Ronald Bin Test.
[30] Nathan Phelps Test.; Ronald Bin Test.
[31] LeBel Test.
[32] Frank Lacey Test.
[33] David Packard Test.
[34] Settlement Agreement (June 6, 2018); http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-SettlementAgreement-Signed(6-6-18).pdf.

hearings, forty-five record requests were issued.[35] Three post-hearing data requests were also issued to seek further clarification of prior responses to questions in the record.

As part of the Settlement Agreement, the parties agreed to a multi-year rate plan that raised rates in the rate year and in each of the two subsequent years. The parties agreed to the following in the rate case: in Rate Year 1, the Settlement increased the revenue requirement by $14.1 million for Narragansett Electric and $5.5 million for Narragansett Gas; in Rate Year 2, the Settlement increased the revenue requirement by another $3.9 million for Narragansett Electric and $5.5 million for Narragansett Gas; and in Rate Year 3, the Settlement increased the revenue requirement by another $2.0 million for Narragansett Electric and $3.3 million for Narragansett Gas.[36]

The parties also agreed to the following revenue requirements in the Power Sector Transformation: in Rate Year 1, the Settlement increased the revenue requirement by $5.3 million for Narragansett Electric and $1.4 million for Narragansett Gas; in Rate Year 2, the Settlement increased the revenue requirement by $4.1 million for Narragansett Electric and $0.5 million for Narragansett Gas; and in Rate Year 3, the Settlement increased the revenue requirement by $1.9 million for Narragansett Electric and $0.6 million for Narragansett Gas.[37]

The Settlement proposed total allowed revenue increases for the combined electric and gas rate case and Power Sector Transformation filing over the three-year period of $48.1 million, for a total Rate Year 1 revenue requirement of $293,273,900 for Narragansett Electric and $220,121,872 for Narragansett Gas. The Settlement also provided for illustrative revenue requirements for the subsequent rate years, but those are not included in this order. Other interim

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[35] The responses to the record requests were entered into evidence at a hearing conducted on July 18, 2018.
[36] Settlement, Attach. 1 at 1 (Bates 130) (June 6, 2018); http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-SettlementAgreement-Attachment(6-18-18).pdf.
[37] *Id*.

rate changes will adjust distribution rates during each of the rate years (including, but not limited to: infrastructure, safety, and reliability for electric and gas, and distribution adjustment factors for gas).[38]

III. August 3, 2018 Open Meeting Decision

At an Open Meeting on August 3, 2018, the PUC considered the evidence in the record and unanimously voted to approve the multi-year rate plan structure set forth in the Settlement with several modifications. The modifications were accepted by the parties and incorporated into an Amended Settlement that was filed with the PUC on August 16, 2018.[39] The following discussion sets forth the modifications and the Commission's rationale.

A. Base Distribution Rate Changes for Rate Year 2 and Rate Year 3

The parties proposed to file the notice of changes to Narragansett Electric Rate Year 2 and Rate Year 3 forty-five days prior to the start of the rate year, or specifically, July 15, 2019 and July 15, 2020. The PUC ordered a modification to the Settlement to require two things: (1) change the filing date to June 1 of each year, increasing the review period to ninety days; and (2) require the filing to include testimony and supporting schedules explaining and itemizing the change in revenue requirement from the prior September 1 through the upcoming September 1. The second change to require additional information, was made to reflect the fact that there will have been

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[38] *Id*. at Attach. 2, Sched. 1 ELEC at 1 (Bates 143), Attach 2, Sched. 1 GAS at 1 (Bates 148).

[39] A full copy of the Amended Settlement can be accessed here: http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-ComplianceFiling-Book%201%20through%207%20-%20August%2016,%202018.pdf. A copy of the Amended Settlement Agreement through Compliance Attachment 2, Schedule 1-GAS (Bates pages 1-136) is attached hereto and marked as Appendix A. The PUC has previously disallowed recovery through rates of lobbying expenses. In response to cross-examination at the hearing, the Company reviewed its revenue requirement schedules and identified lobbying-related expenses that should not have been included in the revenue requirement. Therefore, the Company reduced its rate year ending August 31, 2019 revenue requirement by approximately $234,539 in t/he compliance filing, reflecting a decrease of $208,815 to Narragansett Electric and a decrease of $25,724 to Narragansett Gas. National Grid Response to PUC RR-4; http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-PUC-RR-4%20(July%2016%202018).pdf.

several distribution rate changes during each rate year. The required information should provide a clear nexus between the proposed revenue requirement and the approved Settlement revenue requirement.[40]

B. Revenue Requirement

1. Carrying Charges

Throughout the Settlement, contemplated deferral balances were to accrue carrying charges calculated at the weighted average cost of capital.[41] Deferrals are expected in the following items: Operation and Maintenance costs for Gas Business Enablement, regulatory assets for Gas Business Enablement, deferral balances for Information Services and Cybersecurity activities, Geographic Information Services Data Enhancement, Distribution Supervisory Control and Data Acquisition and Advanced Distribution Management Systems (DSCADA/ADMS), and certain special sector deferral accounts. The PUC questioned whether this proposed treatment was consistent with regulatory policy in Rhode Island.

Company witness Melissa Little[42] explained that deferral balances occur when a certain level of expense is included in rates, but the Company is allowed by the PUC to defer the difference in actual experience against the allowance to a future date. A carrying charge can be allowed to account for the time value of money. When the actual expense is lower than what was included in rates, the carrying charge accrues to ratepayers. Conversely, when the actual expense is higher than the amount included in rates, the carrying charge accrues to the Company. The total expense is credited or recovered through rates at a future point in time.[43]

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[40] The four rate changes are Infrastructure, Safety, and Reliability factor (Apr. 1) and reconciliation (July 1), Revenue Decoupling Mechanism (July 1), and revised Excess Deferred Income Tax filing.
[41] The deferral balances are included in Sections II.C.12, II.C.13, and II.C.13.
[42] Ms. Little was Director, New England Revenue Requirements for National Grid USA Service Company, Inc.
[43] Hr'g Tr. at 28-29 (June 28, 2018).

Ms. Little testified that calculating carrying charges based on the weighted average cost of capital is typically used for capital expense. The customer deposit rate is typically used for operations and maintenance expense in electric rates or the Bank of America prime minus two percentage points rate in gas rates.[44] The Settlement departed from that practice by using a higher percentage carrying charge for all expected deferrals, regardless of type. Division witness Ronald Gerwatowski testified that the weighted average cost of capital was allowed because of the potential magnitude of some of the deferrals.[45] However, Ms. Little confirmed that the current electric storm fund, categorized as operations and maintenance expense, with a negative deferral balance of in excess of $85 million as of the date of the hearing, had only been accruing interest at the customer deposit rate.[46] No party was able to provide a satisfactory rationale for departing from current practice. Therefore, the PUC voted unanimously to follow the current policy of calculating carrying charges on capital expense at the weighted average cost of capital and operations and maintenance expense at the customer deposit rate for electric and the Bank of America prime minus two percentage points rate for gas. The PUC also required a carrying charge to be added to Special Sector deferral accounts.

2. Treatment of Full-Time Equivalent Employees in the Renewable Energy Growth Program

The Renewable Energy Growth Program, a statutorily created feed-in tariff program intended to encourage the development of renewable distributed generation, includes a recovery factor for (1) the payments made to participants, (2) administrative costs, (3) the cost of incremental full-time equivalent employees who administer the program, and (4) statutory

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[44] *Id*. at 29-30.
[45] *Id*. at 40-42, 72. Mr. Gerwatowski, a consultant to the Division, did not proffer written pre-filed testimony but was allowed to testify without objection from any party.
[46] Hr'g. Tr. at 42-43, 139 (June 28, 2018).

remuneration on the tariff-based incentives paid to customers. The parties proposed to transfer funding for the incremental costs being recovered in the Renewable Energy Growth Program budget, including those positions funded through August 2018, from the Renewable Energy Growth Program revenue requirement to base rates. New positions required to support the Renewable Energy Growth Program would continue to be added in future years and accounted for in that program's revenue requirement. The PUC rejected the transfer of full-time equivalents from the Renewable Energy Growth Program budget to the base distribution rates.

The Renewable Energy Growth Program was designed to have its own budget and recovery factor.[47] That recovery factor, unlike distribution rates, is a per-bill factor.[48] In other words, the cost of the program was designed to be passed through to each class of customers as a fixed charge, independent of a customer's individual usage. Transfer of the costs from a fixed charge to a volumetric charge would be inconsistent with the legislature's intent set forth in R.I. Gen. Laws § 39-26.6-25. The decision to recover costs associated with the Renewable Energy Growth Program through the factor, therefore, accomplishes two objectives: (1) it provides transparency of the cost; and (2) it maintains the statutory rate design for recovery of the program costs.

3. Charitable Expenses

The proposed Settlement allowed the Company to include funding in rates for charitable expenses. After a review of the record, the PUC unanimously denied funding in rates for charitable expenses. The PUC found that: (1) such funding provided no clear benefit to ratepayers; (2) the legal rationale relied on by the Rhode Island Supreme Court when it granted utilities rate recovery for charitable expenses over forty years ago has changed; and (3) the changes as to rate recovery

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[47] R.I. Gen. Laws § 39-26.6-25.
[48] *Id*.

of charitable expenses in the Company's other service territories has resulted in discriminatory treatment of Rhode Island ratepayers. The PUC found, therefore, that inclusion of charitable expenses did not result in just and reasonable rates and, further, that the Supreme Court may be amenable to reconsidering its prior holdings based on the facts of this case.

Since 1965, Rhode Island electric and gas utilities have been allowed to include in base distribution rates funding for charitable contributions to various nonprofit organizations. In 1965 and again in 1977, the Rhode Island Supreme Court ruled that charitable expenses can be considered a legitimate cost to be recovered from ratepayers. In *United Transit Authority v. Nunes,* the Supreme Court held that including charitable expense in base rates could be appropriate "when charitable contributions are modest in amount, and productive of good community relations which will benefit the utility or its patrons."[49] In a subsequent case, *Providence Gas Company v. Burman,* the Court stated that "at the rate hearing the company should be given an opportunity to show such items benefit the ratepayer and, accordingly, should be treated as an operating expense."[50] Following these two cases, the PUC, in 1989, provided the utilities with "Guidelines on Charitable Contributions by Regulated Utilities," allowing recovery in rates of up to 0.08% of operating revenues. This guidance has not been revisited in almost thirty years.

While there has been no specific change in law, the PUC in this case questioned the reasonableness of including almost a million dollars of charitable expense in base rates paid for directly by ratepayers.[51] An agency may follow its own guidance but, "if an agency proposes to act in a contested case at variance with a position expressed in a guidance document, it shall

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[49] *United Transit Authority v. Nunes*, 209 A.2d 215 (R.I. 1965).
[50] *Providence Gas Company v. Burman*, 376 A.2d 687, 699 (R.I. 1977).
[51] As shown by the experience in other states, disallowing the expense would not prohibit the utility from continuing to make charitable contributions.

provide a reasonable explanation for the variance. If an affected person in a contested case may have relied reasonably on the agency's position, the explanation must include a reasonable justification for the agency's conclusion that the need for the variance outweighs the affected person's reliance interest."[52] Based on the facts presented in this case, it appears that that circumstances have changed significantly from those upon which the Supreme Court relied over forty years ago. Furthermore, the facts of this case do not meet the standard set forth in *Providence Gas v. Burman,* which appeared to modify the prior broader holding in *United Transit Authority v Nunes* by requiring the PUC to give the utility an opportunity to show a ratepayer benefit. In addition, following a hearing on the issue of charitable expenses, to provide the utility with an opportunity to present evidence on the benefits to ratepayers of charitable expenses, the PUC found that the need for a variance from the 1989 guidance outweighed the utility's reliance on the guidance.

In this proceeding, testimony from the Company's witnesses showed that Rhode Island's ratepayers are being treated differently from similarly-situated ratepayers in National Grid's Massachusetts and New York territories. Company witness Arthur Hamlin, Director of Economic Development and Corporate Citizenship,[53] testified that "Rhode Island is the only jurisdiction where we recover donations through rates. It's shareholder [expense] below the line elsewhere."[54]

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[52] R.I. Gen. Laws § 42-35-2.12(d).

[53] Mr. Hamlin did not submit prefiled testimony. He was presented by the Company at the request of the PUC in order to fully explore the issue of the recovery of charitable expenses. He was allowed to testify without objection from any party.

[54] Hr'g. Tr. at 93 (June 27, 2018). In 1990, the Supreme Court of New York rejected the New York Public Service Commission's policy of allowing regulated utilities to recover charitable contributions in rates. *Cahill v. Public Service Comm'n.*, 556 N.E.2d 133 (N.Y. 1990). In Massachusetts, the Supreme Judicial Court upheld the Department of Public Utilities (DPU) ruling that, in order to get cost recovery of charitable expenses, the utility must show "that its corporate charitable giving is reasonable and provides some clear benefit to ratepayers that is essential to serving them." This decision was affirmed despite the utility's argument that "the task of showing a direct benefit to ratepayers from a charitable gift is so great that the [DPU] in practical effect [has barred] all charitable gifts as a cost of service." *Boston Gas Co. v. Department of Public Utilities*, 539 N.E.2d 1001, 1005-06

Despite this fact, according to Mr. Hamlin, the Company allocates charitable contributions proportionately among its distribution companies generally based on size.[55] He indicated that the amount of charitable giving in Rhode Island is very roughly proportionate to the amount of charitable giving across the National Grid's United States footprint.[56] He continued, "the biggest difference is a big chunk of our core charitable giving in Rhode Island is funded by customers. In other jurisdictions, all charitable giving is funded by shareholders."[57] National Grid's Rhode Island ratepayers are being required to pay expenses that their counterparts in other states are regulatorily prohibited from paying.

Based on this testimony, the PUC also found that the charitable contributions certainly provide benefits to the shareholders in the form of company goodwill in the community. Clearly, National Grid's management has determined that charitable contributions are beneficial to the company even if the cost of those contributions is recovered entirely from shareholders. Given that management's fiduciary duty is to its shareholders first, there is certainly a benefit to shareholders from this activity. However, this benefit does not necessarily translate to a ratepayer benefit as required by *Providence Gas v. Burman*.

Mr. Hamlin stated that it is very difficult to quantify the ratepayer benefit. He explained that each donation provides a community benefit in Rhode Island.[58] However, given the fact that only Rhode Island ratepayers are responsible for the cost of the Company's charitable

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(Mass. 1989). Boston Gas tried again in 1993 and failed to make its showing before the DPU. Investigation by the Department on its own motion as to the propriety of the rates and charges by Boston Gas Company, D.P.U. 98-60, Order at 147-152. A cursory review of subsequent DPU orders and the fact that Mr. Hamlin testified that National Grid does not receive cost recovery in Massachusetts suggests that the utilities have stopped seeking such cost recovery, presumably because they cannot show the charitable expenses provide "some clear benefits to ratepayers that is essential to serving them."

[55] *Id*. at 94-96.

[56] *Id*. at 86, 96.

[57] *Id*. at 96-97.

[58] Hr'g. Tr. at 98 (June 27, 2018).

contributions within its entire multi-jurisdictional United States territory, based on the lack of evidence of a clear ratepayer benefit, the PUC could not find that such discriminatory treatment among the jurisdictions results in just and reasonable rates for Rhode Island ratepayers. For these reasons, the PUC found that in balancing the interests of the ratepayers and shareholders, the need for a departure from the prior guidance outweighed the utility's interest in the recovery of charitable expenses through rates.

In *United Transit Authority*, the Supreme Court noted that, at that time, a majority of jurisdictions in the United States allowed recovery of charitable expenses in rates. Over the past forty-plus years, however, the majority rule has become the minority rule.[59] This was addressed by the Supreme Court of New Jersey in 2001, when it reversed a 1953 ruling[60] that had allowed recovery of charitable contributions through utility rates. In *Petition of New Jersey Water Corporation for an Increase in Rates for Water Sewer and other Tariff Modifications*,[61] the Court held that "no portion of a utility's charitable contributions may be subsidized by the utility's captive ratepayers."[62] In that case, the Court reviewed various court decisions from around the country disallowing recovery through utility rates of charitable contributions. The Court stated that on factor compelling its decision was that the "legal foundation of *Bell 's* ruling has been eroded or

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[59] R. Paul Gee, Who Pays for Charitable Contributions Made by Utility Companies?, ENERGY LAW JOURNAL, Vol 12:363 (1991), available at https://www.eba-net.org/assets/1/6/30_12EnergyLJ363(1991).pdf. Courts cited several reasons for disallowing the expense in rates including, Courts provided the following reasons for disallowing charitable contributions as an expense: imposition on ratepayers of an involuntary expense; ratepayers do not receive a direct benefit; possibility that some ratepayers may disagree with the objectives of a specific charity; general fairness grounds – ratepayers should not be forced to pay additional amounts for charitable purposes at the direction of a regulated monopoly; charitable contributions are discretionary and more appropriate that shareholders pay; and shareholders have the option of selling their shares if unhappy with a utility's charitable contributions. *Id*. at 365-68. *Petition of New Jersey Water Corporation for an Increase in Rates for Water Sewer and other Tariff Modifications*, 777 A.2d 46, 52-54 (N.J. 2001) (citations omitted).

[60] *New Jersey Bell Telephone Co. v. Board of Public Utility Commissioners*, 97 A.2d 602 (N.J. 1953).

[61] 777 A.2d 46 (N.J. 2001).

[62] *New Jersey American Water Corp.*, 777 A.2d at 48.

repudiated during the past five decades." The Court was "also persuaded by the fact that forty states, either by statute, regulation, or case law, [did] not permit a utility's charitable contributions to be treated as an operating expense."[63]

Based on the analysis by the various courts around the country since 1977, either affirming a disallowance of recovery in rates of charitable expenses or overturning decisions of utility commissions that had allowed recovery of such costs, the PUC believes that the Supreme Court of Rhode Island may be persuaded to affirm the PUC's disallowance of these costs, or to reconsider its prior holdings made so many years ago.

In *Providence Gas Company*, the Supreme Court noted that the jurisdictions were not uniform in their treatment of charitable expenses, but cited a New York Public Service Commission case as persuasive authority that the utility should be able to recover the costs if it can show the expense benefits the ratepayer.[64] The Supreme Court of New York has since held that such that charitable expenses are not recoverable in rates on constitutional grounds.[65] Thus, Rhode Island ratepayers are in the position of subsidizing expenses that are directly attributable to shareholders in National Grid's other state service territories. It is difficult to ascertain, then, how Rhode Island ratepayers may be benefiting from paying these same expenses. Furthermore, as noted above, the Company witness was unable to provide any ratepayer benefit resulting from the Company's charitable giving decisions.

Finally, the PUC believes that charitable giving generally is a laudable corporate activity and certainly conveys benefits to shareholders. But National Grid is in a very different position than other publicly-owned companies. As an electric distribution company, National Grid is not

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[63] *Id*. at 53.
[64] *Providence Gas Co. v Burman*, 376 A.2d at 699.
[65] *Cahill v. Public Service Comm'n.*, 556 N.E.2d 133 (N.Y. 1990).

in a competitive market. Its ratepayers constitute buyers. Customers who do not agree with the philosophy of the utility's charitable giving activities, such as gifts to religious organizations, do not have the option of choosing a different utility.[66] This is very different from a customer who can to choose not to purchase a product at a retail shopping establishment if it disagrees with the corporate giving philosophy. It also puts customers in a different position from shareholders who can choose not to invest in a company if they disagree with its corporate giving philosophy. Thus, the PUC does not believe that the State, through the PUC, should be endorsing the Company's corporate giving philosophy by funding utility donations through rates.

4. Earnings Report and Earnings Sharing Mechanism

In the Settlement, the parties agreed to a return on equity for both Narragansett Electric and Narragansett Gas of 9.275%, which the PUC approved. The parties also proposed new earnings sharing mechanisms for both electric and gas. An earnings sharing mechanism is a ratemaking tool whose goal is to both incent the utility to be more efficient and also protect ratepayers from the cost of earnings in excess of the allowed return on equity. The PUC first approved an earning sharing mechanism for Narragansett Electric as part of a multi-year rate freeze plan in 2000. Subsequently, in 2002, it also approved one for the Narragansett Gas predecessor, Southern Union Company, as part of a multi-year rate-freeze plan. The PUC has approved earnings sharing mechanisms of various designs over the past eighteen years.

In 2013, the PUC approved the most recent earnings sharing mechanism for Narragansett Electric and Narragansett Gas whereby accumulated earnings over the authorized return on equity

[66] The customer would have to completely disconnect from the electric grid in order to accomplish this feat.

of 9.5%, up to and including 100 basis points, would be shared 50/50 with customers. Earnings more than 100 basis points above the ROE of 9.5% would be shared 75/25 in favor of customers.[67]

a. Electric

Narragansett Electric shareholders[68] have the opportunity to realize a 9.275% return on equity through the base distribution rates set in this docket. They also benefit from a shareholder incentive on energy efficiency programs. Additionally, they enjoy statutorily mandated shareholder remuneration on long-term renewable energy contracts and the Renewable Energy Growth Program tariff payments, which are expected to grow significantly over the next several years. Finally, there is an additional sharing of benefits that shareholders may realize from the Company's participation in the Forward Capacity Market. When reviewing financial information about National Grid, plc, shareholders see all of these opportunities and accruals together as the profit of the distribution company. However, while the PUC requires the Company to submit earnings sharing reports that show the total earnings and the return on equity alone, the earnings sharing mechanism only applies to the return on equity.

The PUC explored the issue of whether that methodology should change. The PUC considered whether the electric distribution company should be subject to earnings sharing on all actual earnings, regardless of source. In an apparent attempt to provide additional transparency to earnings reports and provide for sharing by ratepayers of all earnings, the parties proposed a

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[67] Order No. 21011 at 106, In re: Application of Narragansett Electric Company d/b/a National Grid for Approval of Change in Electric and Gas Distribution Rates (Docket No. 4323) (Apr. 11, 2013).
[68] This term is somewhat of a misnomer. In order to purchase stock, an investor must purchase National Grid, plc stock. One cannot buy stock in The Narragansett Electric Company d/b/a National Grid because it is a wholly owned subsidiary of National Grid, plc. Despite this fact, Moody's Investor Service does occasionally publish Credit Opinions on The Narragansett Electric Company. In addition, the PUC is required by the Rhode Island General Assembly to consider The Narragansett Electric Company as a standalone entity for purposes of setting a return on equity. R.I. Gen. Laws § 39-1-27.7.1(b) (Actions taken by the commission in the exercise of its ratemaking authority for electric- and gas-rate cases shall be within the norm of industry standards and recognize the need to maintain the financial health of the distribution company as a stand-alone entity in Rhode Island.)

complicated new formula which, when explored fully at the hearing, provided even more additional earnings to the Company before sharing commenced. In addition, the proposal failed to capture all incentives currently provided for in rates and provided no flexibility to respond to new incentives or penalties that might be developed over the term of the multi-year rate plan.[69] Accordingly, the PUC rejected the new proposal finding it too complicated and less beneficial than the then-existing earnings sharing mechanism.

b. Gas

Narragansett Gas shareholders have the opportunity to earn a 9.275% return on equity through base distribution rates set in this docket. They also from benefit a shareholder incentive on energy efficiency programs. Additionally, they have the opportunity to realize an incentive from the Natural Gas Portfolio Management Plan and Gas Procurement Incentive Plan. Just as with the electric side, shareholders investing in National Grid, plc can see all of these opportunities and accruals together as the profit of the distribution company. The earnings sharing mechanism only applies to the return on equity allowed in distribution rates.

The PUC explored the issue of whether that methodology should change and whether the gas distribution company should be subject to earnings sharing on all actual earnings, regardless of source. Under the Settlement, the Company would not have to start sharing at 9.5% despite the fact that no other earnings opportunities would be subject to the earnings sharing provision.[70] The PUC rejected the new proposal, finding that it did not provide additional benefit to ratepayers when compared to the then-existing mechanism.

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[69] Hr'g. Tr. at 102-26; National Grid's Response to RR-45.
[70] Hr'g. Tr. at 97-100 (June 28, 2018).

c. Modification to the Settlement for Electric and Gas Earning Sharing Mechanisms

As part of its decision, the PUC provided language that was incorporated into the settlement. The language was applicable to both electric and gas earnings. The PUC's ruling required that earnings sharing begin at 9.275%. If the Company earns between 9.275% and 10.275%, earnings will be shared 50/50 with customers. If the level of earned ROE is greater than 10.275%, customers will receive 75% of those earnings and the Company will receive 25%.

5. Gas Business Enablement Program/Information Services Reports

The revenue requirement includes 85% of the projected costs for Gas Business Enablement and Cybersecurity and Information Services Technology Modernization Programs, subject to a true-up and prudence review after the end of the rate plan.[71] The Gas Business Enablement plan was described as a multi-year, enterprise-wide, gas-business program that will implement three, inter-related, core operating capabilities (Work Management, Asset Management, and Customer Enablement) necessary to support National Grid's U.S. gas distribution business.[72] The Settlement set forth a cap against which costs could be trued-up for Gas Business Enablement, but did not include a cap on Cybersecurity and Information Service Technology Modernization Programs. While the PUC found both programs to be supported by the evidence, it determined that the true-up provisions should be capped at the cost for the programs allocated to Rhode Island as represented in the Settlement. Thus, the PUC ordered the Settlement to be amended to still allow a regulatory asset to be created, but to clarify that in no case will the deferral of expenses within the regulatory asset result in recovery of a total cost in excess of the Company's forecasted

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[71] Amended Settlement at Sections 12-13.
[72] Johnston and Connolly Jt. Test. at 5-6.

allocated cost of $17.4 million ($5.1 million for Narragansett Gas and $12.3 million for Narragansett Electric).

The Settlement set forth certain reporting requirements for these programs. The PUC ordered the Company to also include the current status of the deferral position within the regulatory asset. At a minimum, the Company shall report the deferral balance, the increase or decrease, and ending balance.

6. Commencement of Investments to Enable a Modern Grid, Grid Modernization Plan, and Advanced Metering Functionality Filing

The Settlement included funding for certain investments to enable a modern grid and provided for funding to develop an updated Advanced Metering Functionality Business Case. While the PUC allowed funding in Rate Year 1 for the System Data Portal, Geographic Information System Data Enhancement Project, and the Advanced Metering Functionality study, the PUC disallowed funding in Rate Year 1 for items in Section 14.c of the Settlement. Included were "all other Grid Mod (excluding DSCADA, Geographic Information System, System Data Portal, Feeder Monitoring)" on Attachment 1, page 2 of the Settlement. They were deferred to Rate Year 2.

The Settlement contemplated the filing of an Advanced Metering Functionality Business Case, no later than December 1, 2018, and a Grid Modernization Plan, no more than six months following that filing.[73] The PUC found that an Advanced Metering Functionality Business Case to be integral to any Grid Modernization Plan. Therefore, the parties were encouraged to file the

[73] The Advanced Metering Functionality Business Plan filing has since been extended after requests by the Company and with approval of the PUC.

two as close together as possible. The timeframe of the Grid Modernization Plan should encompass the end of any proposed advanced metering functionality implementation.

The PUC provided twelve minimum requirements for inclusion in the Grid Modernization Plan.[74] These were incorporated into the Amended Settlement. Relying on the testimony from the June 18, 2018 hearing,[75] the PUC also set forth sixteen elements that should be included in an Advanced Metering Functionality Business Case.[76]

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[74] The minimum requirements were: Objectives for the electric grid to advance the Goals for the Energy System and Rate Design Principles, and potential visibility requirements of the benefit-cost framework in Docket No. 4600 Guidance Document; An explanation of the role of currently active programs; Investments and technology deployments that are planned through the end of any proposed advanced metering functionality implementation; Functionalities required to achieve those objectives identified in part one of this list; A review of options for candidate technologies to deliver those functionalities; A transparent, updated benefit cost analysis that fully incorporates the Docket No. 4600 framework; An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments; A plan and explanation for the integration and leveraging of customer-side technologies and resources in the near and long-term; Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities; An explanation of congruency with New York and Massachusetts; A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence; An explanation of the relationship between electrification of heating and transportation and efficiency in the distribution system planning process.

[75] Hr'g. Tr. at 36-52, 112-13, 119-20 (June 18, 2018).

[76] Updated costs for advanced metering functionality deployment based on information gained from a procurement effort; A transparent, updated benefit cost analysis that fully incorporates the Docket No. 4600 framework; An investigation of alternative business models and ownership models; An analysis of data latency; Deployment details; The role of non-regulated power producers, articles to share customer information, customer engagement; An ownership model for assets and telecom; Detail of advanced metering functionality functionalities; how Rhode Island will achieve those functionalities, and when the functionalities will be available; Identification of the most cost-effective way to achieve the functionalities, and how the functionalities align to the policy objectives; An explanation of whether the realization of those functionalities will require additional future work and costs over twenty years; Identification of what functionalities the advanced metering functionality will achieve that are part of the grid modernization plan and which are in addition to the grid modernization plan; Identification of which functionalities are dependent on full-scale roll out instead of a targeted roll out; A business case based on Rhode Island-only scenarios and Rhode Island plus New York scenarios; A business case based on the length (duration) of meter; Identification of the critically linked parts of grid modernization and advanced metering functionality; Identification of whether the advanced metering functionality solution would allow for proper net metering according to the tariff.

7. Clean Energy Programs

The Settlement provided for three clean energy programs similar to those originally proposed as part of the Company's Power Sector Transformation filing in Docket No. 4780. The funding in each rate year was subject to a deferral mechanism whereby the costs and annual base distribution rate allowances allocated to each of these "Special Sector Programs" are separately monitored and reconciled at the end of each Rate Year. Underspending is either deferred to subsequent years if the underspending is caused by a reasonable delay in implementation or, if caused by cost reductions or unspent funds for other reasons, the funds are held for the benefit of ratepayers in a manner to be determined by the PUC. The Company is responsible for any overspending unless the PUC later allows the creation of a regulatory asset. The burden of proof would be on the Company to prove the reasonableness of the regulatory asset, such standard which includes demonstrating that the costs were prudently incurred consistent with the program objectives and the overspending was out of the reasonable control of the Company.[77]

a. Electric Transportation

i. Off-Peak Charging Rebate Pilot

The PUC approved an off-peak charging rebate pilot. The pilot will reward customers for charging their electric vehicle during off-peak hours, study customer charging patterns at various charging locations and levels, understand customer responsiveness to time-differentiated price-signals, and evaluate technology and partnership alternatives to monitor and report charging.[78] The PUC found that it represented a small scale, targeted program that was limited in scope, time, and spending, and it was designed to test the feasibility of a future program or rate design. The

[77] Settlement at Section II.C.20.
[78] Settlement at Section II.C.20.a.i.

primary design and value of the pilot is to test rather than to achieve. Results will be reported in the Company's Annual Evaluation Report, discussed below.

ii. Charging Station Demonstration Program

The parties had identified one of the barriers to electric vehicle adoption was lack of publicly available charging infrastructure. Charging infrastructure can be expensive.[79] The Settlement provided that Narragansett Electric will demonstrate new approaches to electric charging infrastructure development. The Settlement allowed Narragansett Electric to own a certain amount of the charging infrastructure. The remainder would be owned by third parties. The amount included in rates for the site-host model would be used to fund the make-ready work necessary for charging infrastructure to be installed, owned, and operated by the site host. The amount included in rates for the utility ownership model would also include funding of the charging station. The initiative included forecasts of the number of ports to be deployed for both Level 2 and direct current fast charging stations based on the program budget. Both the make-ready model and utility ownership model were designed so that the cost to the site host was comparable "from a financial perspective...so it is really a level playing field and there's no financial upside, higher financial upside for a site host in one or the other."[80]

In approving the proposal, the PUC disallowed funding for utility ownership of the charging stations. The PUC found that the make-ready model would contribute to overcoming barriers associated with the cost of customer-side upgrades necessary to install charging

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[79] "[T]he make-ready model…addresses the cost barrier that is most suitable to be resolved by an electric distribution company, namely system upgrades and certain wiring expenses. The costs of such a program should be reasonably defined and can come with clear limit on expenditures per site or per charging station. Combined with a well-designed charging station rebate program and appropriate consumer protections, this model is the best way to jointly satisfy a number of different policy goals." Docket No. 4780, Lebel Test. at 35-36.
[80] Hr'g. Tr. at 204 (June 18, 2018).

infrastructure. The PUC also found, however, that the utility ownership model for Level 2 charging would not overcome those stated barriers for apartment buildings, income eligible community sites, or public transit stations customers. The Company ownership model may provide a convenience to customers who do not wish to maintain the equipment.[81] The Company owned model, however, does not reduce the cost below the cost of make-ready work. In fact, where the Company would then be rate basing the investment and earning a return on it,[82] the PUC found that the record did not support the reasonableness of the added overall ratepayer cost for the convenience. Nor did the record support that utility ownership of direct current fast chargers was necessary to meet demand under the forecasts presented in the record or that it would provide additional visibility to them. The PUC indicated that it would consider reevaluating utility ownership at the end of Rate Year 1 if there was evidence of unmet need.

iii. Discount Pilot for Direct Current Fast Charging Station Accounts

The Settlement provided for a time-limited discount on electric bills for dedicated, direct current fast charging electric accounts. The pilot provided for a 100% discount of the distribution demand charge for a period of three years from the start of service. The pilot was funded up to $300,000 per year. The PUC approved the pilot, finding that it represented a small scale, targeted program that was limited in scope, time, and spending, and that it was designed to test the feasibility of a future program or rate design. The pilot is designed to test whether removing the demand charge would reduce a barrier to investment in direct current fast chargers. However, the PUC modified the proposal such that the 100% rebate would be effective in Rate Year 1, subject

[81] *Id*. at 244, 251
[82] *Id*. at 200-01.

to modification to those customers enrolling after Rate Year 1.[83] This modification should protect against overpayment of rebates and may inform the answer to the question of the "right" level of rebate.

iv. Electric Transportation Initiative Evaluation[84]

Narragansett Electric will produce, file with the PUC, and publicly present an Annual Evaluation Report describing implementation of the electric transportation initiative and documenting the information gained through this initiative and any recommendations to enhance the program. The PUC included a number of minimum requirements to be included in the report.[85]

b. Electric Heat

The Settlement provided funding for equipment incentives to lower the up-front cost barrier for Rhode Island residential customers to convert from their current heating system to efficient cold-climate air-source or ground-source heat pump systems. The PUC disallowed funding for the electric heat initiative finding that it had already approved a well-designed cost-

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[83] The PUC provided that the discount for participants who enroll in Rate Year 1 will be equal to 100% of the distribution demand charge for a period of three years from the start of service. Sixty days prior to enrollment for Rate Year 2 and Rate Year 3, the Company shall make as part of the first electric Transportation Evaluation and annual program modification report, with input from the Power Sector Transformation Advisory Group on the appropriate level of the discount based on enrollment data and lessons learned for approval by the PUC. The results of the pilot and any proposed direct current fast charger demand charges or rebates will be reviewed as part of the next multi-year rate plan.

[84] The PUC made no modifications to the proposed Fleet Advisory Services, an initiative where Narragansett Electric will, through a combination of internal and third-party expertise, offer a new advisory service to support electrification of customer fleets. Settlement, Section 17.a.v.

[85] The minimum requirements are that the report include: charging Station location, category (as shown on page 54 of the Settlement), in-service date, and utilization; effectiveness of demand charge discount, and free-ridership and spillover effects; learnings on how the company can integrate electric vehicles with minimal impacts on the cost of the distribution system, including an understanding of the effectiveness of the off-peak charging pilot; evaluation of the effectiveness of each component of the initiative in stimulating consumer adoption of electric vehicles, including an understanding of the effectiveness of the type and level of the incentive; results of fleet advisory services, including how many fleet vehicles were converted to electric vehicles at the end of each rate year and at the end of the rate plan; incremental effect of the CO_2 electric vehicle performance incentive mechanism, including the level of electric vehicle adoption is attributable to the strategic behavior the performance incentive mechanism will promote and the level of electric vehicle adoption that would have occurred without the performance incentive mechanism; and evaluation of the Company's impact on fleet electric vehicle adoption.

effective program in the most recent energy efficiency program year. The evidence in the record did not support funding the same type of program through two different recovery mechanisms. The PUC will continue to consider heat pump initiatives in the energy efficiency program dockets.

c. Strategic Electrification Marketing Fund

The Settlement provided for $200,000 funding in Rate Years 1 and 2 and $300,000 in Rate Year 3 for the creation of a strategic electrification marketing fund that included electric vehicle and electric heat advertising. The PUC rejected funding for electric vehicle education and outreach and oil dealer training and support but allowed funding for off-peak marketing. It found that the former two violated the prohibition in R.I. Gen. Laws § 39-2-1.2 against including advertising in base rates where the advertising is designed to promote the use of the utility's product or service or its image. The witnesses testified that the fund will be designed to increase electric vehicle adoption and increase the use of electric heat and would include the National Grid branding on marketing material and infrastructure. The witnesses testified that an intended outcome of the fund will be increased electricity use.[86] The Off-Peak Charging Demonstration is not designed to promote the use of electricity, but rather to promote shifting load to off-peak periods, something not disallowed by the statute.

d. Energy Storage Demonstration

The Settlement provided for an energy storage demonstration project in which the Company will issue requests for proposals for two energy storage solutions. One would be for a behind-the-meter storage system co-located with a direct current fast charger site. It would consist of an approximate 250 kW two-hour energy storage system, supporting approximately two to six

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[86] Hr'g. Tr. at 212-13 (June 14, 2018).

direct current fast charger ports. The second one would be a front-of-the-meter storage system. It would consist of an approximate 500 kW three-hour energy storage system for the primary purpose of realizing distribution system value.[87]

The PUC found that it represented a small scale, targeted program that was limited in scope, time, and spending, and that was designed to test the feasibility of a future program or rate design. The primary design and value of the pilot is to test rather than to achieve. The PUC amended the provision to require Narragansett Electric to file the draft requests for proposals thirty days prior to issuance, to ensure the PUC understands the barriers the pilot demonstration is designed to overcome and the learnings the Company intends to obtain from the project.

8. Capital Efficiency Mechanism

The parties proposed a capital efficiency mechanism to apply to Narragansett Electric's annual Infrastructure, Safety, and Reliability plan investments. The purpose of the mechanism was to incent the utility to invest its approved budget efficiently and below cost. There were several design questions that arose during the hearings. The PUC rejected the mechanism as not appropriately included in the base distribution rate case and, instead, opened a new docket to separately consider the appropriateness and design of such a mechanism as part of the upcoming Infrastructure, Safety, and Reliability matters.

9. Performance-Based Incentive Mechanisms

The Settlement originally proposed seven performance incentive mechanisms in three categories that the parties stated were intended to advance state policy goals and drive benefits for customers: (1) System Efficiency: Annual MW Capacity Savings; (2) Distributed Energy

[87] Settlement at 17.d.

Resources: Installed Energy Storage Capacity; (3) Distributed Energy Resources, CO_2: Electric Vehicles; (4) Distributed Energy Resources, CO_2: Electric Heat; (5) Distributed Energy Resources: Light Duty Government and Commercial Fleet Electrification; (6) PST Enablement: Awarded Low Income and Multi-unit Electric Vehicle Supply Equipment Sites; and (7) PST Enablement: Distributed Generation (DG) Interconnection – Time to ISA.[88]

In evaluating the performance incentive mechanism designs, the PUC posed eleven questions taken from principles set forth in prior dockets assessing performance incentives.[89] The PUC found that only one performance incentive mechanism, the System Efficiency: Annual MW Capacity Savings mechanism satisfied the principles. The PUC, however, found that overall, funding for unquantified benefits should be disallowed in all performance incentives mechanisms. The PUC, therefore, also modified the System Efficiency performance incentive mechanism to remove funding for unquantified benefits. The PUC, also noting that unquantified benefits are, however, important and that there is merit in rewarding the Company for advancing them, directed the Power Sector Transformation Advisory Group to develop transparent and well-defined metrics

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[88] At the hearing, the PUC requested the DG Interconnection – Time to ISA be evaluated based on historical data. The response to Record Request 17 showed that the Company had already been exceeding the metric; http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-PUC-RR-17%20(July%2016%202018).pdf.

[89] Does the incentive promote the realization of new consumer and societal benefits? (Docket No. 4774 – Renewable Energy Growth Program); Does the incentive promote behavior that the utility otherwise would not take? (Docket No. 4774 – Renewable Energy Growth Program); Is there a clear nexus between the metric and the expected benefits? (Docket No. 4774 – Renewable Energy Growth Program); Is there a clear, stated reason why the incentive is needed to achieve each specific objective? (System Reliability Procurement Standards); Is the incentive designed to promote superior utility performance and significantly advance the expected benefits as efficiently as possible? (Energy Efficiency/System Reliability Procurement Standards); Is the incentive designed so that customers receive most of the benefit? (Energy Efficiency/System Reliability Procurement); Is the incentive designed to grant increasing levels of rewards to the utility for higher levels of performance? (Energy Efficiency/System Reliability Procurement); Will the design and implementation of the incentive be completely transparent and fully document and reveal inputs and methodologies to ensure no duplication of incentives across various ratepayer funded programs? (Energy Efficiency/System Reliability Procurement Standards); Is it possible to compare the cost of achieving the metric to the potential benefits? (Docket No. 4774); What objectives does this incentive promote? (Energy Efficiency/System Reliability Procurement Standards); Are there opportunities for the company to earn multiple incentives for attaining the same objective? (System Reliability Procurement Standards).

for describing unquantified benefits and providing evidence that unquantified benefits are advancing.

The PUC approved all other metrics, including proposed "scorecard" metrics, as track-only metrics with no funding attached. Finally, the PUC also indicated that there were three metrics it would be willing to reevaluate for funding prior to the end of the multi-year rate plan. Prior to Rate Year 2, the PUC may reevaluate whether to allow a financial incentive on the CO2:Electric Vehicles. The PUC may also reevaluate whether to allow a financial incentive at the end of Rate Year 2 on Activated Apartments and Disadvantaged Electric Vehicle Supply Equipment Sites if the Company demonstrates an unmet need in these sectors. The Distributed Energy Resources: Light Duty Government and Commercial Fleet Electrification performance incentive mechanism may also be reevaluated prior to Rate Year 2 for financial incentives if the Company demonstrates how this incentive is consistent with the PUC's policy for performance metrics.

C. Additional Provisions

1. Low Income Rate Design and Reporting

The Settlement Agreement removed funding for certain ratepayer funded Low Income Energy Assistance Program (LIHEAP) matching grants for gas recipients, expanded the low-income discount for both gas and electric customers, and changed the way that these discounts are funded by ratepayers.

National Grid has historically offered an income-eligible electric ratepayer assistance program. Prior to September 1, 2018, electric customers that were enrolled in the low-income rate received a waiver of the monthly customer charge and a discount on their distribution charges.[90]

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[90] The discounted distribution charges consist of a waiver of the $5 monthly customer charge, and a 38% discount of the per kW distribution charge. Docket No. 4323, National Grid's Compliance Filing, Attach. 3D at p. 2.

Because the discount was only on a portion of the bill (e.g., energy supply itself was excluded from the discount calculation), fluctuations in other rates on customers' bills resulted in average overall bill discounts of approximately 15%.

Prior to September 1, 2018, a gas customer had to be receiving LIHEAP assistance to be eligible for the distribution discount rate. The discount was 10% of the distribution portion of the bill. Thus the discount compared to the total bill equaled approximately 5% of the total bill. However, customers receiving LIHEAP were credited with a matching grant from the gas company (funded by ratepayers) that, when added to the distribution rate discount, provided more significant rate relief against the total bill.

The Settlement revised the low-income rate to provide a 25% discount off the total electric and/or gas bill for most low-income customers. In addition, for those customers whose eligibility for the low-income rate is based on receiving Medicaid, General Public Assistance, or Rhode Island Works benefits, the discount would set the discount at 30% off the total monthly bill.[91] The additional 5% discount to those entering the program through the lowest income-eligibility programs introduced a tiered, income-based approach to electric and gas rates. To be eligible for the low-income rate, a customer must meet the income guidelines for the federally-funded LIHEAP or receive one of the following: Supplemental Security Income, Medicaid, Supplemental Nutrition Assistance Program, general public assistance or the Rhode Island Works.[92]

Prior to the Settlement, the cost of serving low income customers not collected through the discounted rates was collected through higher distribution rates applied to non-income-eligible ratepayers, including non-income-eligible residential, commercial, and industrial customers. The

[91] RIPUC No. 2215; https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/ri/a60_ripuc_2215.pdf.
[92] *Id*.

Settlement provided that the cost of the low-income discount will be recovered by National Grid through a new and fully reconciling recovery charge. The Company had argued that the existing cost recovery mechanism shifted too much risk onto the Company. The Wiley Center, and others supporting the new funding mechanism contended that because of this perceived risk, National Grid had a disincentive to advise customers of the availability of the discounted rate and of customers' potential eligibility. The result, according to the parties, was a large underserved population. Under the Settlement, enrollment in these rates will be reviewed through new reporting requirements approved in the Amended Settlement Agreement.

The PUC also identified, through the input of parties during the rate case, a need to reassess the type and manner of information gathered from National Grid on a periodic basis. While the PUC and Division gather a great deal of data on a monthly, quarterly, and annual basis, it became clear that some of that information was both redundant and inadequate for appropriate cost-benefit analysis. Therefore, the PUC directed the Company, Division, and Wiley Center to work with PUC staff to develop revised data-gathering reports to inform better analysis relevant to National Grid's next rate case. The reporting requirements were to be designed to inform how low-income rates, programs, and discounts advance the Rate Design Principles contain in the Docket No. 4600 Guidance Document, including information that will be needed to support future investigation into more dynamic low-income rate design.[93] This is a foundational first step. A secondary goal was to consolidate the many different reporting requirements into one comprehensive document.

[93] Following the PUC's approval of the Amended Settlement, the PUC staff convened meetings with the Company, GWC, and Division. A new report was approved by the PUC in August 2019. The PUC will be reviewing the report with the parties in early 2020 to determine if any of the categories need to be amended and if prior reports have been superseded and may be replaced with this one report.

2. Power Sector Transformation Advisory Group Reporting

The parties agreed to the creation of a Power Sector Transformation Advisory Group comprised of the Company, Division, OER and representatives of the following interests: environment, clean energy industry or businesses, low income, NPP, community groups, and additional members as the Company, the Division, and OER may agree. The PST Advisory Group would review at a high level the progress on the delivery of all Power Sector Transformation components of the multi-year rate plan and to provide guidance, and prioritization to support successful delivery of the components in a comprehensive manner.[94] The PUC directed the Power Sector Transformation Advisory Group to participate in periodic technical sessions with the PUC to provide updates on its work.

3. Cost Allocation of Power Sector Transformation Costs

The Amended Settlement included an agreed-upon allocated cost-of -service study and rates calculated as a result of the cost of service study. At the hearing, Company witness Gorman[95] explained that the allocation of grid modernization and special sector programs was the result of settlement discussions and there was insufficient detail to run expenses through the allocated cost study models. He explained that, although the Company and its customers will ultimately benefit from these programs, "it was impossible to reasonably assign the costs or the benefits to any class at this point."[96] He agreed that the revenues were allocated but the expenses related to grid modernization and special sector programs were not.[97] Thus, Mr. Gorman explained that anything beyond the core business distribution revenue requirement in year one was not produced by the

[94] Amended Settlement Section 17.c.
[95] Howard Gorman was the President of HSG Group, Inc., a consulting firm that specializes in rate and regulatory support for utilities.
[96] Hr'g. Tr. at 17 (June 25, 2018).
[97] *Id*. at 17-18.

allocated cost of service study.[98] He agreed that if the expenses had been run through the models, there certainly would have been differences in the outcomes, but he did not think they would be significant.[99] Based on this testimony, the PUC accepted the allocation methodology for these expenses to be reasonable in the context of an overall settlement. In future cases, however, the PUC expects that all proposed costs will be included in the allocated cost of service study to ensure rate classes are paying their fair share of expenses.

4. Cost Recovery for Performance Incentive Mechanism Awards

The parties originally settled on using the electric revenue decoupling mechanism as the cost recovery vehicle for any performance incentive awards earned by the Company. The proposed revisions to the revenue decoupling mechanism would recover the performance incentives through a uniform per-kWh adjustment factor.[100] Company witness McCabe[101] testified that this mechanism was chosen for administrative efficiency with little thought given to whether or not the recovery should be through a uniform recovery factor or through an allocation factor.[102] Company witness Gorman agreed that where distribution rates are set based on an allocated cost of service study, uniform reconciliation factors can have the effect of moving a class of customers away from their respective cost of service, although he had not assessed the magnitude of such a shift.[103]

Revenue decoupling mechanisms in Rhode Island annually reconcile the revenue requirement allowed in the Company's most recent base distribution rate case to actual billed

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[98] *Id*. at 21-22.
[99] *Id*. at 25-26.
[100] Hr'g. Tr. at 44-45 (June 25, 2018).
[101] Scott M. McCabe was Manager of New England Electric Pricing for National Grid USA Service Company, Inc.
[102] *Id*. at 46-47.
[103] *Id*. at 53-54.

distribution revenue for the applicable twelve-month period.[104] In the event the revenues were higher than allowed, customers receive a credit in the following twelve-month period. Conversely, if revenues were lower than allowed, the Company recovers the incremental amount over the following twelve-month period. Such mechanisms have typically been proposed by utilities to make up lost revenues due to a reduction in load expected from energy efficiency or other public policy programs. In Rhode Island, the mechanisms are statutory.

A revenue decoupling mechanism is not a "catch-all" recovery mechanism. Any modifications to the tariff must be reviewed on a case-by-case basis to determine the appropriateness. There may be times when it makes sense to use the revenue decoupling mechanism, but this is not one of those times. The proposal is not designed to cover a limited time, limited scope, small adjustment. There is a desire by parties to move toward more performance incentive mechanisms in addition to, or in place of, the traditional return on equity earnings potential. While the revenue decoupling mechanism may be the most expedient way to recover such earnings today, it will not always be.

The PUC found it to be more appropriate to allow a new cost recovery mechanism. The new factor will allow the Company to file for recovery of performance incentives already earned from approved performance incentive mechanisms. It will not forecast incentive recovery, but the recovery mechanism will reconcile to ensure the Company receives and ratepayers pay no more or less than allowed. The factor shall be calculated in accordance with the results of the cost of service study used in this case. This will ensure transparency, that customers are paying their fair share, and that the utility is realizing the full value of its incentive.

5. Revised Excess Deferred Taxes True-Up

[104] R.I. Gen. Laws § 39-1-27.7.1.

As part of the Tax Cuts and Jobs Act of 2017, the Company recorded $116 million and $51 million estimates of customer-related excess deferred income tax for Narragansett Electric and Narragansett Gas, respectively. The actual amounts will not be fully calculable until the Company files its federal income tax returns in December 2018. The difference will affect the annual target revenue for purposes of revenue decoupling and may affect base distribution rates. The Company will make a filing no later than March 1, 2019 to calculate the actual amounts.[105] In the original Settlement, the language provided was subject to interpretation.[106] The Company subsequently provided amended language in response to Record Request 30. The PUC approved the revised language for inclusion in a compliance filing or amended settlement finding it to be clearer.

IV. Amended Settlement and August 24, 2018 Open Meeting Decision

Following the August 3, 2018 Open Meeting, the parties had the option to either reject the PUC's modifications and move to full evidentiary hearings on the parties' original positions or to accept the modifications and file an amended settlement.[107] On August 16, 2018, National Grid filed an Amended Settlement, signed by all parties, incorporating the PUC's modifications.[108]

At an Open Meeting held on August 24, 2018, the PUC reviewed the Amended Settlement Agreement and found that it complied with all findings and orders of the PUC made on August 3, 2018. Accordingly, the PUC approved the revenue requirement and rate design set forth in the Amended Settlement Agreement for effect on September 1, 2018. As part of the decision, it also approved the gas revenue requirements set forth in the Amended Settlement Agreement for effect

[105] The Company filed the Excess Deferred Tax matter on March 1, 2019; http://www.ripuc.org/eventsactions/docket/4770page.html. The PUC issued Order No. 23615 on June 12, 2019; http://www.ripuc.org/eventsactions/docket/4770-NGrid-EDIT-Ord23615_6-11-19.pdf.
[106] Hr'g. Tr. at 56-63 (June 26, 2018).
[107] Settlement, Section III.C.
[108] National Grid reserved its right to raise the issue of inclusion of charitable contribution expense in base rates in the next rate case.

September 1, 2019 and September 1, 2020. The electric revenue requirements for those effective dates were subject to additional compliance filings on June 1, 2019 and June 1, 2020, respectively.

In Rate Year 1, the Amended Settlement increased the revenue requirement by $12 million for Narragansett Electric and $5.8 million for Narragansett Gas;[109] in Rate Year 2, the Amended Settlement increased the revenue requirement by another $3.9 million for Narragansett Electric and $5.7 million for Narragansett Gas; and in Rate Year 3, the Amended Settlement increased the revenue requirement by another $2.5 million for Narragansett Electric and $3.4 million for Narragansett Gas.

The Amended Settlement Agreement included a revenue requirement in the Power Sector Transformation filing of the following: in Rate Year 1, the Settlement increased the revenue requirement by $2.1 million for Narragansett Electric and $0.0 for Narragansett Gas; in Rate Year 2, the Settlement increased the revenue requirement by $6.6 million for Narragansett Electric and $1.9 million for Narragansett Gas; and in Rate Year 3, the Amended Settlement increased the revenue requirement by $1.9 million for Narragansett Electric and $0.6 million for Narragansett Gas.

The total allowed revenue increases for the combined electric and gas rate case and Power Sector Transformation filing over the three-year period in the Amended Settlement was $46.3 million. The total Rate Year 1 revenue requirement of $291,130,879[110] for Narragansett Electric and $218,634,846[111] for Narragansett Gas was approved.

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[109] The revenue requirement set forth in the Amended Settlement reflected modifications to the capital structure and cost of capital as a result of a debt issuance that occurred on or about July 27, 2018. Amended Settlement Redlined; http://www.ripuc.org/eventsactions/docket/4770-4780-NGrid-AmendedSettlement(Redlined)_8-10-18.pdf.
[110] Compliance Attach. 2, Schedule 1-ELEC at 1.
[111] Compliance Attach. 2, Schedule 1-GAS at 1.

V. Rate Year Two

On May 31, 2019, Narragansett Electric filed with the Commission its Electric Base Distribution Rates for Rate Year 2 Compliance Filing together with joint testimony and schedules of Melissa Little and Robin Pieri. The Company set forth an increase in the revenue requirement of $3.7 million for Narragansett Electric plus another $6.6 million for Power Sector Transformation expense in Rate Year 2. The combined $10.3 million increase resulted in a base rate revenue requirement of $294,892,686, plus Power Sector Transformation revenue requirement of $8,679,579, for a combined total electric revenue requirement of $303,572,265.[112]

The witnesses explained the PUC's ruling on the Company's March 1, 2019 excess adjusted deferred income tax true-up compliance filing changed the revenue requirements for Narragansett Electric for the three-year rate plan. This was reflected in the Company's Second Compliance Filing.[113] However, the change in each rate year's revenue requirement was too small to warrant a change in base distribution rates at that time. Therefore, the PUC allowed the Company to reflect the updated revenue requirements that included the excess adjusted deferred income tax differential to be reflected in Narragansett Electric's annual revenue decoupling mechanism reconciliation filings. This was done through an adjustment to the amount of the Annual Target Revenue for the applicable period.[114]

On July 31, 2019, the Division filed a memorandum from John Bell, Chief Accountant, indicating that he had reviewed the filing and recommended the PUC find that it was in compliance

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[112] Little and Pieri Test. at Sch. 1, 5, 6.
[113] Docket No. 4770, Application of The Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric and Gas Base Distribution Rates Excess Deferred Income Tax True-Up – Supplemental Compliance Filing; Second Compliance Filing; http://www.ripuc.org/eventsactions/docket/4770-NGrid-Excess%20ADIT-Second%20Compliance_5-30-19.pdf.
[114] Little and Pieri Jt. Test. at 8-9; http://www.ripuc.org/eventsactions/docket/4770-NGrid-RY2-ComplianceFiling%20(5-31-19).pdf.

with the PUC's decision approving the Amended Settlement Agreement and adjusted deferred income tax order.[115] No other party filed testimony or memoranda. On August 8, 2019, the PUC reviewed the filings and approved the Rate Year 2 revenue requirement as filed, finding it to be in compliance with prior PUC orders.

Accordingly, it is hereby

(23823) ORDERED:

1. The Amended Settlement, filed on August 16, 2018 in this docket, is hereby approved as being in compliance with the Commission findings on August 3, 2018, for effect on September 1, 2018.
2. The Narragansett Electric Company d/b/a National Grid's Electric Base Distribution Rates for Rate Year 2 Compliance Filing made on May 31, 2019 are hereby approved for effect on September 1, 2019.
3. The parties shall comply with all other findings and instructions contained in this Report and Order and in the Amended Settlement.
4. The Narragansett Electric Company d/b/a National Grid shall continue to file all periodic reporting requirements previously ordered in Docket Nos. 2930, 3617, and 4243 unless otherwise previously superseded.

[115] Bell Mem. (July 31, 2019).

EFFECTIVE AT WARWICK, RHODE ISLAND ON SEPTEMBER 1, 2018 AND SEPTEMBER 1, 2019 PURSUANT TO OPEN MEETING DECISIONS ON AUGUST 3, 2018, AUGUST 24, 2018, AND AUGUST 8, 2019. WRITTEN ORDER ISSUED MAY 5, 2020

PUBLIC UTILITIES COMMISSION

Margaret E. Curran, Chairperson

Marion S. Gold, Commissioner

Abigail Anthony, 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 seven (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.

The Narragansett Electric Company
d/b/a National Grid

Amended Settlement Agreement
Docket Nos. 4770 and 4780
August 16, 2018

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:
nationalgrid

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STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

In Re: The Narragansett Electric Company d/b/a National Grid's Application to Change Electric and Gas Base Distribution Rates	)	Docket No. 4770
In Re: The Narragansett Electric Company d/b/a National Grid's Proposed Power Sector Transformation (PST) Vision and Implementation Plan	)	Docket No. 4780

AMENDED SETTLEMENT AGREEMENT

The Narragansett Electric Company d/b/a National Grid (the Company)[1] enters into this amended settlement agreement (the Settlement Agreement) with the Division of Public Utilities and Carriers (Division); the Office of Energy Resources (OER); the U.S. Department of the Navy and the Federal Executive Agencies (collectively, Navy/FEA); Conservation Law Foundation (CLF); Energy Consumers Alliance of New England, Inc. d/b/a People's Power and Light (PPL)[2]; Sierra Club (SC)[3]; Natural Resources Defense Council (NRDC)[4]; Acadia Center (Acadia); Northeast Clean Energy Council (NECEC); the George Wiley Center (GWC); New

[1] The term "Company" refers to The Narragansett Electric Company's electric and gas distribution operations on a collective basis. The electric and gas distribution operations of The Narragansett Electric Company together represent the entirety of the regulated operations conducted in Rhode Island by the Company. In this Settlement Agreement, the regulated entity is referred to as the Company. Where there is a need to refer to the individual electric and gas distribution operations of the Company, the terms "Narragansett Electric" or "Narragansett Gas," respectively, are used in this Settlement Agreement.

[2] PPL intervened in Docket No. 4770 individually and in Docket No. 4780 jointly with Sierra Club and Natural Resources Defense Council.

[3] SC intervened in Docket No. 4780 jointly with PPL and Natural Resources Defense Council.

[4] NRDC intervened in Docket No. 4780 jointly with PPL and Sierra Club.

Energy Rhode Island (NERI); Wal-Mart Stores East, LP and Sam's East, Inc. (collectively, Wal-Mart); Direct Energy Business, LLC, Direct Energy Services, LLC, and Direct Energy Solar (collectively, Direct Energy)[5]; ChargePoint, Inc. (ChargePoint)[6]; and National Railroad Passenger Corporation (Amtrak)[7] (collectively, the Settling Parties and, each individually, a Settling Party[8]), with regard to the Company's Application for Approval of a Change in Electric and Gas Base Distribution Rates Pursuant to R.I. Gen. Laws §§ 39-3-10 and 39-3-11 (the Application) and the Company's proposed Power Sector Transformation (PST) Vision and Implementation Plan (PST Plan). The Company submitted the Application and the PST Plan to the Rhode Island Public Utilities Commission (the PUC) on November 27, 2017.

Background:

The Company's Application to the PUC requested a change in base distribution rates to address a total Rate Year[9] revenue deficiency of $41,294,907 for Narragansett Electric and a total revenue deficiency of $30,322,543 for Narragansett Gas. The Company's Application was filed to seek recovery of costs necessary for the safe and reliable operation of the Company's electric and gas distribution systems for the benefit of Rhode Island customers. On March 2, 2018, the Company revised its request to account for the impacts of the Tax Cuts and Jobs Act (the Tax Act), which reduced the federal corporate income tax rate from 35 percent to 21 percent. The March 2, 2018 revision reduced the Company's Rate Year revenue deficiency to $27,434,395 for Narragansett Electric and $18,408,489 for Narragansett Gas. This revision also

[5] Direct Energy is an intervenor in Docket No. 4780 only.

[6] ChargePoint is an intervenor in Docket No. 4780 only.

[7] Amtrak is an intervenor in Docket No. 4770 only.

[8] PPL, SC, and NRDC intervened jointly in Docket No. 4780 and together are considered a Settling Party with respect to that docket.

[9] The Rate Year is the twelve-month period ending August 31, 2019.

included a $6.7 million correction from a miscalculation of accumulated deferred taxes in the Company's filing that the Division identified. Subsequently, on May 9, 2018, the Company made a second revision to its request to account for additional impacts of the Tax Act and to address certain corrections identified during the course of discovery in Docket No. 4770, also including the acceptance of an adjustment that was recommended by the Division to the amortization of excess deferred income taxes. The May 9, 2018 revision reduced the Company's Rate Year revenue deficiency to $18,877,761 for Narragansett Electric and $15,451,041 for Narragansett Gas. Accordingly, after the Company's second revision to its revenue requirement, the Company's total requested revenue increase was $34,328,802.

Additionally, concurrent with filing the Application, the Company filed its PST Plan to propose investments to further the State of Rhode Island's power sector transformation goals, as identified through the Docket No. 4600 proceedings and through the power sector transformation stakeholder process, which resulted in the Rhode Island Power Sector Transformation Phase One Report to Governor Gina M. Raimondo. The PST Plan included requests for limited Rate Year funding and a proposed funding mechanism for the Company's proposed power sector transformation investments. The PUC separated the PST Plan from the Application and created Docket No. 4780 to assess the PST Plan. After the PUC initiated Docket No. 4780, the Company revised its request related to the PST Plan and requested: (1) approval of $2 million in Rate Year funding to conduct a planning process for the implementation of Advanced Metering Functionality (AMF); (2) approval of its proposed annual PST Plan process, whereby the Company would submit annual PST Plans for the PUC and Division to review and approve PST investments; (3) approval of the Company's proposed PST Provision, which provided for the recovery of PST Plan costs on a fully reconciling basis; and (4) guidance from the PUC on the categories of proposed PST investments outlined in the Company's PST Plan filing.

The Settling Parties have filed testimony with the PUC, engaged in discovery and negotiations regarding the matters specified in the articles of this Settlement Agreement, and asserted competing and disputed claims with regard to certain issues contained in the Application and the PST Plan, including, but not limited to: (a) the magnitude of the proposed revenue deficiencies for Narragansett Electric and Narragansett Gas; (b) the scope and structure of the Company's proposed power sector transformation programs, such as AMF implementation, electric vehicle enablement, and grid modernization technology upgrades; (c) a multi-year rate plan; (d) the structure and role of performance incentive mechanisms; and (e) the appropriate cost recovery mechanisms.

The Settling Parties now wish to resolve the contested issues raised by (1) the Division, Navy/FEA, Wal-Mart, NERI, and Acadia in direct testimony and OER and GWC in written comments filed with the PUC on April 6, 2018 in Docket No. 4770; (2) Amtrak in its motion to intervene out of time filed with the PUC on June 1, 2018 in Docket No. 4770; (3) CLF jointly with PPL/SC/NRDC and CLF jointly with NRDC/PPL in direct testimony filed with the PUC on April 17, 2018 in Docket No. 4780; and (4) the Division, Navy/FEA, NERI, Acadia, Direct Energy, ChargePoint, and CLF jointly with NECEC in direct testimony and OER in written comments filed with the PUC on April 25, 2018 in Docket No. 4780, on mutually agreeable terms.

The Settling Parties believe that a settled resolution will reduce costs for Rhode Island customers through the elimination of resource-consuming litigation and achieve a just and reasonable result that takes into account the diverse views of all the Settling Parties.

Accordingly, in consideration of the exchange of promises herein contained, the Settling Parties hereby agree, subject to approval by the PUC, as follows:

ARTICLE I: INTRODUCTION

A. Procedural History

Docket No. 4770: At the outset of these proceedings, the PUC ordered that the Company's PST Plan be moved into Docket No. 4780 and be considered on a separate procedural schedule. Additionally, the PUC directed that it would not consider any settlement proposal until after the Division and intervenors submitted direct testimony setting forth their positions on the various elements of the Company's Application.

Since filing its Application on November 27, 2017, the Company has responded to 1,439 data requests issued by the PUC, the Division, the Navy/FEA, Wal-Mart, NERI, and Acadia. The Division and the intervenors also have responded to data requests issued by the Company and the PUC. On April 6, 2018, the following Division and Intervenor witnesses filed direct testimony in Docket No. 4770: Division Witnesses Tim Woolf (Policy), Michael Ballaban jointly with David J. Effron (Revenue Requirement), Tina Bennett jointly with Alan Neale (Gas Business Enablement), Gregory Booth (Grid Modernization), Matthew Kahal (Cost of Capital and Return on Equity), Tim Woolf jointly with Melissa Whited (Additional Cost of Capital Considerations and Benefit Cost Analysis), Roxie McCullar (Depreciation), Roger Colton (Low Income Discount and Income Eligible Proposals), John Athas (Electric Allocated Cost of Service and Rate Design), and Bruce Oliver (Gas Allocated Cost of Service and Rate Design), raising issues relating to the calculation of the proposed revenue requirement, the computation of allowable uncollectible expense, the cost of capital, and other ratemaking issues including, but not limited to, cost allocation, rate design, the appropriate structure and role of performance incentive mechanisms, and the appropriate cost recovery mechanisms for grid modernization investments.

- Navy/FEA Witness Ali Al-Jabir, raising issues relating to rate design and revenue allocation;
- Wal-Mart Witness Gregory W. Tillman, raising issues relating to revenue allocation, rate design, and return on equity – as well as the impact of the Tax Act;
- NERI Witness Karl Rabago, raising issues relating to the Company's proposed revenue requirement, return on equity, rate design, forecasting, revenue allocation, and the streetlighting tariff; and
- Acadia Witness Mark LeBel, raising issues relating to rate design and return on equity.

The following parties also intervened in Docket No. 4770 and filed written comment:

- OER in relation to the alignment of the Company's proposals with the State of Rhode Island's overall policy goals for the future of the power sector; and
- GWC in relation to the Company's low income discount rate design proposals.

CLF, NECEC, PPL, and Amtrak intervened in Docket No. 4770, but did not file direct testimony or written comment.

On May 9, 2018, the Company filed rebuttal testimony responding to the issues contested by the Division and the intervenor witnesses. Specifically, the Company filed the rebuttal testimony of Company Witnesses Robert E. Hevert (return on equity and capital structure); Ned Allis (depreciation); Joseph F. Gredder (electric forecasting); Theodore E. Poe, Jr. (gas forecasting); John Gilbert, Daniel J. DeMauro, and Mukund Ravipaty (information systems); Anthony Johnston and Christopher J. Connolly (Gas Business Enablement); Raymond J. Rosario, Jr., Alfred Amaral, III, and Ryan M. Constable (operational expense); Maureen Heaphy (human resources); Melissa Little (revenue requirement); Howard S. Gorman (electric allocated cost of service study, revenue allocation, and rate design); Paul M. Normand (gas allocated cost of service study, revenue allocation, and rate design); Ann E. Leary and Scott McCabe (gas and electric pricing, respectively); Kayte O'Neill (PST policy); Rob Sheridan (grid modernization); John Leana (AMF); and Meghan McGuinness and Timothy R. Roughan (performance incentive mechanisms). These witnesses responded to the positions of the Division and intervenor witnesses on each of the identified issues.

To date, the PUC has held 13 open meetings on December 20, 2017, January 3, January 19, February 2, March 5, April 13, April 16, April 17, April 23, May 15, May 16, June 7, and June 19, 2018, at which the PUC analyzed the Company's Application and the respective positions of the Company, the Division, and the intervenors.

Docket No. 4780: Since the initial filing of its Application and the PST Plan on November 27, 2017, and, after the PUC initiated Docket No. 4780 for separate consideration of the PST Plan, the Company has responded to 469 data requests issued by the PUC, the Division, the Navy/FEA, PPL/SC/NRDC, NERI, and NECEC. On April 17, 2018 and/or April 25, 2018, the following Division and Intervenor witnesses filed direct testimony in Docket No. 4780:

- Division Witnesses Gregory Booth, raising issues relating to the Company's proposed grid modernization investments, and Tim Woolf jointly with Melissa Whited, raising issues related to: (a) multi-year rate plans, (b) performance incentive mechanisms, (c) the Company's electric vehicle proposals, (d) the Company's electric heat proposals, (e) the Company's electric storage initiative, (f) the Company's proposal for Company-owned solar generation, (g) AMF, and (h) the Company's benefit-cost analyses;

- Navy/FEA Witness Ali Al-Jabir, raising issues relating to: (a) cost recovery mechanisms for PST proposals; (b) cost allocation and rate design; and (c) performance incentive mechanisms;
- CLF jointly with PPL/SC/NRDC Witness Douglas B. Jester, raising issues relating to AMF and the Company's electric vehicle proposals;
- CLF jointly with PPL/NRDC Witness Benjamin A. Stafford, raising issues relating to the Company's electric heat proposals;
- NERI Witness Karl Rabago, raising issues relating to: (a) overall PST policy and vision; (b) cost recovery mechanisms for PST investments; (c) performance incentive mechanisms; and (d) benefit cost analyses;
- NECEC and CLF Witness Nathan Phelps, raising issues relating to: (a) the Company's proposed grid modernization investments; (b) AMF; (c) the Company's electric storage initiative; (d) the Company's proposal for Company-owned solar generation; and (e) the Company's proposed Income Eligible Customer Rewards Program;
- NECEC and CLF Witness Ronald J. Binz, raising issues relating to performance-based regulation, performance incentive mechanisms, and recovery of PST-related costs;
- Direct Energy Witness Frank Lacey, raising issues relating to: (a) the Company's proposed grid modernization investments; (b) AMF; (c) time-varying rates and (d) the Company's electric vehicle proposals;

- Acadia Witness Mark LeBel, raising issues relating to: (a) performance incentive mechanisms; (b) AMF; (c) the Company's electric vehicle proposals, and (d) the Company's electric heat proposals; and
- ChargePoint Witness David Packard, raising issues relating to the Company's electric vehicle proposals.

OER also intervened in Docket No. 4780 and filed written comment raising issues relating to: (a) performance incentive mechanisms; (b) the Company's proposed grid modernization investments; (c) AMF; (d) the Company's electric vehicle proposals; (e) the Company's electric heat proposals; (f) the Company's electric storage initiative; (g) the Company's proposal for Company-owned solar generation; and (h) cost recovery mechanisms for PST proposals. The GWC also intervened in Docket No. 4780 but did not file direct testimony or written comment.

In addition to the pre-filed written testimony and the responses to data requests that have been filed in Docket No. 4780, the PUC also held technical sessions on the various elements of the Company's PST Plan. Specifically, on January 26, 2018, the PUC held a technical session on the Company's proposed grid modernization investments and cost recovery mechanisms. On January 31, 2018, the PUC held a technical session on the Company's proposed performance incentive mechanisms. On February 8, 2018, the PUC held a technical session on the Company's AMF proposal. On February 20, 2018, the PUC held two technical sessions: one on the Company's electric vehicle proposals, and another on the Company's electric heat proposals. On February 21, 2018, the PUC held two more technical sessions: one on the Company's electric storage initiative, and another on the Company's proposal for Company-owned solar generation.

The Settling Parties have conducted ongoing settlement discussions. The Company and the Division have conducted bilateral negotiations on the various proposals in the Application and the PST Plan. Additionally, the Company has held additional bilateral negotiations with certain other intervening parties to address specific areas of interest and concern to those parties. To supplement those bilateral negotiations and ensure that the positions of all the Settling Parties received appropriate attention and consideration, the Division and the Company arranged for several face-to-face meetings at which all intervenors had an opportunity to raise and advocate for the issues that were of principal concern to them and to negotiate the substance of this Settlement Agreement. Ultimately, the Company and the Division drafted the Settlement Agreement to include all the issues and matters raised by all the Settling Parties during these negotiations. After the Company and the Division completed drafting the Settlement Agreement, they shared the draft with all the intervenors and provided them an opportunity for further comments and revision. This Settlement Agreement, therefore, is the product of a collaborative, inclusive, and comprehensive process that fairly considered the interests of all parties and stakeholders.

The Settlement Agreement was initially filed with the PUC on June 6, 2018. The PUC commenced the hearing on the Settlement Agreement on June 12, 2018; held 11 days of settlement hearings on June 14, June 15, June 18 through June 22, June 25 through June 28, 2018; and concluded the hearing on July 18, 2018. The PUC subsequently held a series of open meetings on July 2, July 3, July 18, July 20, and July 31 to discuss the Settlement Agreement and the testimony from the settlement hearings. On August 3, 2018, the PUC held an open meeting at which the PUC approved the Settlement Agreement filed on June 6, 2018 with modifications.

Following the PUC's open meeting decision, the Settling Parties convened to review and discuss the PUC's modifications, which have been incorporated into this Settlement Agreement.

B. Settling Parties' Statement

This Settlement Agreement is based on extensive discovery and negotiations among the Settling Parties concerning all issues involved in: (1) establishing new base distribution rates for the Company's electric and gas operations to become effective September 1, 2018; and (2) making investments in new programs and initiatives to facilitate power sector transformation. The Settling Parties agree that the outcome of this Settlement Agreement is just and reasonable and in the public interest.

C. Scope

The Settlement Agreement addresses the full scope of all issues presented in and resolves all issues contested among the Settling Parties in both Docket No. 4770 and Docket No. 4780 and establishes base distribution rates for the Company's electric and gas residential, commercial and industrial (C&I), and outdoor lighting customers in Rhode Island.

ARTICLE II: TERMS OF SETTLEMENT

A. Multi-Year Rate Plan Overall Framework

As a result of the collaborative and inclusive settlement negotiations among the Settling Parties in addition to bilateral negotiations between the Company and the Division on the various proposals in the Application and the PST Plan, the Settling Parties have developed a comprehensive set of terms and conditions for a three-year rate plan for Narragansett Electric and Narragansett Gas. The terms and conditions of this rate plan are set forth below and in the Attachments to this Settlement Agreement. Specifically, this Settlement Agreement addresses the following topics:

1. Effective Date and Term;
2. Changes in Revenue Requirements for Three Rate Years;
3. Base Distribution Rate Changes for Rate Year 2 and Rate Year 3;
4. Narragansett Electric - Revenue Requirement;
5. Narragansett Electric - Revenue Allocation, Rate Design, and Tariffs;
6. Narragansett Electric - Earnings Report and Earnings Sharing Mechanism;
7. Narragansett Electric - Other Tariffs and Reconciling Mechanisms;
8. Narragansett Gas - Revenue Requirement;
9. Narragansett Gas - Revenue Allocation, Rate Design, and Tariff;
10. Narragansett Gas - Earnings Report and Earnings Sharing Mechanism;
11. Narragansett Gas - Other Tariffs and Reconciling Mechanisms;
12. Gas Business Enablement Program;
13. Cyber Security and Information Services (IS) Technology Modernization Programs;
14. Commencement of Investments to Enable a Modern Grid;
15. Grid Modernization Plan (GMP);
16. AMF;
17. Clean Energy Programs;
18. Capital Efficiency Mechanism for Narragansett Electric;
19. Performance-Based Incentive Mechanisms;
20. Tracking and Deferral of Certain “Special Sector” Program Costs and Revenues;
21. Next Rate Case Filing;
22. Additional Provisions; and
23. Other Provisions.

B. Definitions

"**Docket 4600 Guidance Document**" means the PUC's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid adopted on October 27, 2017 in Docket No. 4600-A.

"**Effective Date**" means September 1, 2018, or such other date as the PUC may determine.

"**ISR**" means the infrastructure, reliability, and safety planning and cost recovery process governed by Section 39-1-27.7.1(c), (d) of Rhode Island General Laws.

"**Rate Year 1**," sometimes referred to herein as "RY1," means September 1, 2018 through August 31, 2019.

"**Rate Year 2**," sometimes referred to herein as "RY2," means September 1, 2019 through August 31, 2020.

"**Rate Year 3**," sometimes referred to herein as "RY3," means September 1, 2020 through August 31, 2021.

The three rate years are referred to herein collectively as "Rate Years," or "RYs," and individually as a "Rate Year," or "RY."

"**Test Year**," means July 1, 2016 through June 30, 2017.

C. Rate Plan

1. Effective Date and Term

The term of the Company's electric and gas rate plan is three years, beginning September 1, 2018 and continuing through August 31, 2021 (Rate Plan or MRP). For administrative reasons, certain targets and mechanisms are on different twelve-month schedules (*e.g.,* calendar year (CY) periods), as provided herein. In addition, unless specifically noted in this Settlement

Agreement, all terms of this Settlement Agreement will continue in effect until changed by the PUC.

2. Changes in Revenue Requirements for Three Rate Years

This Settlement Agreement provides for the following changes in base distribution rate annual revenue requirements for Narragansett Electric and Narragansett Gas for each of the Rate Years of the Rate Plan (*i.e.*, Rate Year 1, Rate Year 2, and Rate Year 3) to provide funding for the Company's electric and gas operations and PST Plan initiatives, including: Updated AMF Business Case (as defined in Section 16 below); GIS Investments; System Data Portal; DSCADA; other Grid Modernization investments; Electric Transportation; and Electric Storage.

	Narragansett Electric ($M)	Narragansett Gas ($M)	Total ($M)
Base Case			
Rate Year 1	$12.0	$5.8	$17.8
Rate Year 2	$3.9	$5.7	$9.6
Rate Year 3	$2.5	$3.4	$5.9
Subtotal – Base Case	$18.4	$14.9	$33.3
Power Sector Transformation			
Rate Year 1	$2.1	$0.0	$2.1
Rate Year 2	$6.6	$1.9	$8.4
Rate Year 3	$1.9	$0.6	$2.5
Subtotal – PST	$10.6	$2.5	$13.0
Base Case plus PST			
Rate Year 1	$14.1	$5.8	$19.9
Rate Year 2	$10.5	$7.6	$18.0
Rate Year 3	$4.3	$4.0	$8.4
TOTAL	$28.9	$17.4	$46.3

A summary of the revenue requirement settlement terms is provided in Attachment 1, Page 1. The base case components of the base distribution revenue requirements for Narragansett Electric and Narragansett Gas are set forth in Attachment 2, Schedules 1-ELEC and

2-GAS, respectively. The PST Plan components of the base distribution revenue requirements for Narragansett Electric and Narragansett Gas are set forth in Attachment 4 and Attachment 5.

To reach a settlement in these proceedings, the Company accepted the majority of the downward adjustments to operating expenses and rate base that were recommended by the Division, as outlined in the table below.

	Rate Year ($M)		
	1	2	3
Company Base Rate Request			
March 2, 2018 (REV-1) Base Rate Request	$45.8		
Refund of Excess Deferred Taxes	($9.0)		
A&G Expense Reclassification to Capital	($4.5)		
March 2, 2018 (REV-1) Base Rate Request adjusted	$32.4[10]		
Settlement Adjustments			
Subtotal - Expense Adjustments	($14.3)		
Subtotal - Rate Base Adjustments	($3.1)		
Adjustment to Revenue Requirement for Rate Base Adjustments	($0.3)		
Total Adjustments	($14.6)		
Subtotal - Adjusted Base Rate Request	$17.8	$9.6	$5.9
PST Additions			
PST Adjustments	$2.1	$8.4	$2.6
Total Settlement - Base Case plus PST	$19.9	$18.0	$8.5

As detailed in Attachment 2, for Rate Year 1, the revenue requirements are based on the following parameters and adjustments:

a. A return on equity (ROE) of 9.275 percent;

b. A capital structure recommended by the Division and overall cost of capital, including a 51 percent common equity ratio. The resulting weighted average cost of capital (WACC) is applicable to the calculation of the revenue requirements associated with the

[10] As described in Section 4.h. (Narragansett Electric) and Section 8.h. (Narragansett Gas), the Company will include all other revenue requirement adjustments either (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal cost of service, and (3) resulting from changes presented in the rebuttal testimony in its compliance filing revenue requirement in this docket. These adjustments account for the difference between the Company's adjusted March 2, 2018 request of $32.4 million and the request of $34.3 million submitted with the Company's rebuttal filing on May 9, 2018.

ISR Plans and any other reconciling mechanism that calculates a return based on the approved WACC, which is the same as it is today;

c. A reduction in depreciation expense of $3.1 million. The Company's depreciation rates for Narragansett Electric and Narragansett Gas have been reduced and are set forth in Attachment 2, respectively;

d. The impacts of the tax rate change to 21 percent and the amortization of excess accumulated deferred income taxes (ADIT);

e. A reduction to Administrative and General expense to reflect a reclassification to capital;

f. An adjustment to labor expense to reflect a smooth hiring pattern over the term of the Rate Plan for all incremental full time equivalents (FTEs) that were included in the Company's November 27, 2017 initial filing but have not yet been filled, as shown on Attachment 2, Schedule 12 and Attachment 3, Workpaper 4;

g. An adjustment to the calculation of the average of net write-offs as a percentage of total revenues for the five years ended June 30, 2017 for Narragansett Gas to eliminate the twelve-month period ended June 30, 2013 from this calculation. The average write-off rate is applied to the Rate Year 1 revenue to calculate the pro forma Rate Year 1 uncollectible accounts expense. This adjustment reduces the average Narragansett Gas write-off rate from 2.08 percent to 1.91 percent;

h. An adjustment to reflect the Division's position on Gas Growth capital;

i. Adjustments to reflect the Division's position on Gas Business Enablement and the IS Technology Modernization Programs (see Sections 12 and 13 below);

j. Existing reconciling mechanisms for costs recovered outside of base distribution rates remain in effect as operating today, as listed in Attachment 22; and

k. Adjustment to Service Company rents and Gas Business Enablement for reduced ROE at 9.275 percent; and

l. Adjustment for the depreciation expense impact of the growth adjustment.

3. Base Distribution Rate Changes for Rate Year 2 and Rate Year 3

Under the Rate Plan governed by this Settlement Agreement, base distribution rates for Narragansett Electric and Narragansett Gas shall change annually at the start of each Rate Year, effective September 1, 2018, September 1, 2019, and September 1, 2020. The annual increase in base distribution rates shall be allocated to each of Narragansett Electric's and Narragansett Gas's respective rate classes in the same proportion as determined from the final revenue allocation of the revenue requirements for Rate Year 1. The allocation of the increases to rate classes is presented in Attachment 8 for Narragansett Electric and Attachment 16 for Narragansett Gas, and base distribution rates based upon each rate class's Rate Year revenue requirement for Rate Year 2 and Rate Year 3 is contained in Attachment 9 for Narragansett Electric and Attachment 16 for Narragansett Gas.

a. The development of each Rate Year's base distribution rates consistent with the Rate Plan governed by this Settlement Agreement is incorporated in this Settlement Agreement, and through the PUC's approval of this Settlement Agreement, the base distribution rates for the Rate Years are approved for implementation, subject to any changes pursuant to Sections 8, 15, and/or 16;

b. Bill impacts for all rate classes comparing the rates in effect at the time of the Company's initial filing and Rate Year 1; Rate Year 1 and Rate Year 2; and Rate

Year 2 and Rate Year 3, are presented in Attachment 10 and Attachment 17 for Narragansett Electric and Narragansett Gas, respectively; and

c. The PUC's approval of the base distribution rates contained in this Settlement Agreement represents its determination that the proposed base distribution rates are reasonable and consistent with the MRP.

On or before June 1 of each year of the Rate Plan, Narragansett Electric shall submit to the PUC its Summary of Retail Delivery Rates tariff updating this tariff to reflect the base distribution rates approved by the PUC as part of this Settlement Agreement, together with testimony and supporting schedules explaining and itemizing the change in revenue requirement from the prior September 1 through the upcoming September 1, unless otherwise changed pursuant to a separate proceeding before the PUC consistent with Sections 8, 15, and/or 16.

The rate schedule provisions of Narragansett Gas's tariff contained in Attachment 19 include the base distribution rates for each of the Rate Years.

4. <u>Narragansett Electric - Revenue Requirement</u>

a. *Revenue Requirements for the Rate Years*. This Settlement Agreement provides that the base distribution rates for Narragansett Electric shall be set in these proceedings based on a Rate Year 1 revenue requirement increase of $14.1 million, a Rate Year 2 revenue requirement increase of $10.4 million, and a Rate Year 3 revenue requirement increase of $4.4 million, using a test-year ended June 30, 2017 (Test Year), as detailed in Attachment 1 to this Settlement Agreement.[11] The resulting revenue requirements for the Rate Years are: $293.2 million for RY1, $303.5 million for RY2, and $308.0 million for RY3. The base case revenue requirement for Rate Year 1 was determined using a total rate base of $729.5 million; pro forma

[11] Schedule A to this Settlement Agreement lists the attachments supporting this Settlement Agreement. Schedule A also provides a cross-reference to the bound volume that contains each respective attachment.

Test Year operating revenues of $279.2 million; distribution operating expenses of $150.6 million; income taxes of $1.1 million; and an overall rate of return of 6.97 percent. The base case revenue requirement for Rate Year 1 established by the Settling Parties allows for recovery of a revenue deficiency of $12.0 million in Rate Year 1, which represents a reduction of $29.3 million from the November 27, 2017 original request and a reduction of $6.9 million from the May 9, 2018 second revision to the cost of service.

b. *Calculation of Rate Base*. The Settling Parties agree that rate base for Narragansett Electric for the Rate Years shall be calculated to include capital additions approved in the ISR Plans for Fiscal Year 2014 (Docket No. 4382), Fiscal Year 2015 (Docket No. 4473), Fiscal Year 2016 (Docket No. 4539), Fiscal Year 2017 (Docket No. 4592), and estimated Fiscal Year 2018 (Docket No. 4682), estimated Fiscal Year 2019, and estimated Fiscal Year 2020 additions through Rate Year 1 (*i.e.*, August 31, 2019). Narragansett Electric's rate base for the Rate Years also shall be calculated to include non-ISR capital additions through August 31, 2021.[12] Narragansett Electric's rate base for the Rate Years also shall reflect the unamortized cost of long-term debt issuance expense. ISR-eligible capital additions for Rate Year 2 and Rate Year 3 will be addressed in the ordinary course outside of base distribution rates through the ISR Plan and included for recovery in future ISR Plans.

c. *Other Adjustments*. The revenue requirements contained in Attachment 2 reflect adjustments agreed to by the Settling Parties associated with the Tax Cuts and Jobs Act, a change in the Company's A&G capitalization policy, and estimated Service Company excess deferred federal income taxes.

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[12] Capital additions currently recovered through the ISR Plan will be included in rate base as of September 1, 2018, concurrent with the effective date of new base distribution rates in these proceedings. Therefore, the capital-related portion of the ISR factor will be set to zero as of September 1, 2018.

d. *Operating Expenses*.

i. Uncollectible Accounts Expense

The Settling Parties agree that the recovery of distribution-related uncollectible-accounts expense[13] shall be calculated using Narragansett Electric's actual five-year average ratio of actual distribution net write-offs as a percentage of distribution revenues (as calculated in Docket No. 4323 and Docket No. 4065) ending with the Test Year, or 1.30 percent. The actual, five-year average write-off rate of 1.30 percent shall also be used to calculate recovery of the uncollectible accounts expense allowance in those reconciling mechanisms that provide for the recovery of uncollectible account expense.

ii. Non-Deferrable Storm Expense

This Settlement Agreement provides that the amount of non-deferrable storm expense allowed for recovery through base distribution rates shall be set at $3,193,756[14] annually, subject to the following: If the actual level of non-deferrable storm expense in any calendar year commencing in 2019 is greater than $5,193,756, then the amount in excess of $5,193,756 shall be charged to the Storm Contingency Fund (the Storm Fund). If the actual level of non-deferrable storm expense in any calendar year commencing in 2019 is less than $1,193,756, then the amount by which $1,193,756 exceeds the actual non-deferrable storm expense in that calendar year shall be credited to the Storm Fund. Because new base distribution rates go into effect on September 1, 2018, the dead band for 2018 shall be applied to the average of

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[13] This amount does not include the commodity-related portion of uncollectible accounts expense, which is recovered through various reconciling mechanisms as governed by their respective tariff provisions (see Pre-Filed Direct Testimony of Company Witness Melissa A. Little at Page 47 (Bates Page 51 of Book 8). The calculation of uncollectible account expense is provided in Schedule MAL-22 (Rev-2) (Rebuttal Book 3).

[14] Represents the five-year average of non-deferrable storm expense for the twelve month periods ended June 30, 2013 to June 30, 2017 (see Schedule MAL-31 (Rev-2) at Page 7, Line 13, Column (e)).

$3,722,000[15] for 8/12ths of the year and $3,193,756 for 4/12ths of the year, or $3,545,919.

iii. Storm Contingency Fund

As further described on Attachment 23, the Storm Contingency Fund is subject to the provisions of the Joint Proposal and Settlement between the Company and the Division filed with the PUC on September 25, 2017 in Docket No. 4686 and approved by the PUC on April 27, 2018 (Docket No. 4686 Settlement Agreement).

The total base distribution rate contributions to Narragansett Electric's Storm Fund effective September 1, 2018 will be $7.3 million annually, which includes:

(1) $4.3 million in annual base distribution rate contributions; and

(2) $3.0 million of supplemental Hurricane Sandy base distribution rate contributions through their currently scheduled expiration in March 2021. Thereafter, the continuation of this supplemental $3.0 million annual Storm Fund contribution will be subject to PUC review.

In addition, a contribution of $21.1 million annually is credited to the Storm Fund from the Storm Fund Replenishment Factor through its currently scheduled expiration in June 2021.

e. *Return on Rate Base*

i. Capital Structure

The Settling Parties agree that the revenue requirement established by this Settlement Agreement for Narragansett Electric shall be determined by the WACC and its components, as shown in Attachment 2.

[15] The amount of non-deferrable storm expense allowed for recovery through base distribution rates for Narragansett Electric was set at $3,722,000 in Docket No. 4323, representing the five-year average of non-deferrable storm costs for calendar years 2007 to the 2011 test year in Docket No. 4323. As approved in Docket No. 4323, a $2,000,000 dead band was established, which would trigger additional charges to the Storm Fund for non-deferrable storm costs in excess of $5,722,000 in a calendar year, or credits to the Storm Fund for non-deferrable storm costs less than $1,722,000. See Docket No. 4686 Settlement Agreement, Paragraph (9), at 3.

The actual capital structure shall be adjusted further to include the long-term debt issued on July 27, 2018 pursuant to the separate Settlement Agreement entered into between the Division and the Company dated February 15, 2017, in Division Docket D-17-36, which was approved as set forth in the Division's Report and Order issued February 19, 2017, and as set forth in the statement of basic terms that the Company filed with the Division on August 1, 2018.

ii. Cost of Long-Term Debt

As stated above, the new long-term debt shall be pro-formed at an interest rate of 3.919 percent and debt expense estimated at 0.46 percent, or $1.61 million. Upon completion of the long-term debt issuance, the revenue requirement established by the Settlement Agreement shall be adjusted to use the actual weighted cost of long-term debt and debt expense after the new debt issuance. The Company shall make a filing to the PUC within 60 days of the completion of the long-term debt issuance to adjust base distribution rates for Narragansett Electric to incorporate the actual debt rate and issuance costs in base distribution rates.

iii. Return on Common Equity

The Settling Parties agree that the return on common equity shall be set at 9.275 percent.

iv. Weighted Average Cost of Capital

The computation of the WACC established by this Settlement Agreement is set forth in Attachment 2. The weighted average cost of capital set forth in Attachment 2, as adjusted pursuant to Section 4(e), above, shall be used for ratemaking purposes, including in the ISR Plan, until the next base distribution rate proceeding for Narragansett Electric.

f. *Miscellaneous Corrections*. The Settling Parties agree that Narragansett Electric shall make all corrections (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal cost of service, and (3) resulting from changes presented in the rebuttal testimony of Company Witness Melissa A. Little in finalizing the cost of service for Narragansett Electric.

5. Narragansett Electric - Revenue Allocation, Rate Design, and Tariffs

a. *Allocated Cost of Service*. The Settling Parties agree, for the purpose of settlement in these proceedings (except with respect to the customer charge as reflected in this Settlement Agreement), to use the allocated cost of service study (ACOSS) included in Attachment 6, consistent with the ACOSS filed by Narragansett Electric on May 9, 2018.[16] In future rate cases, the Company shall include all costs associated with the PST programs and investments in its revenue requirements and ACOSS.

b. *Revenue Allocation and Rate Design*. The Settling Parties agree that Narragansett Electric's revenue allocation contained in Attachment 8, prepared consistent with the Updated Revenue Allocation (Schedule HSG-3(R)) filed with the PUC on May 9, 2018, and which shall be incorporated into the design of base distribution rates, shall include:

i. A reduction to present revenue for Rate X-01 of $322,000, which is a reduction from Rate X-01 present revenue of $692,000 (shown on Line 40 in Attachment 8, Page 2) to $370,000 to address the concerns raised by Amtrak in these proceedings regarding the significant difference between Rate X-01 revenue at present rates and Rate X-01's allocated rate year revenue requirement. This represents a reduction that balances a significant benefit to Amtrak with the impact this reduction will have on other customers. In addition, the Company will commit, on a going forward basis, to (1) in future general rate cases, propose other changes to address any remaining difference between Rate X-01 revenue at then-present rates and Rate X-01's allocated rate year revenue requirement resulting from an ACOSS filed in those general

[16] See Rebuttal Testimony of Company Witness Howard S. Gorman, at Page 5 (Bates Page 7 of Rebuttal Book 6), and Schedule HSG-1A(R), at Bates Page 37 of Rebuttal Book 6.

rate cases, and will specifically propose to address any difference, to the extent the ACOSS identifies a significant difference in relation to differences identified for the Company's other rate classes, and (2) inform Amtrak of its next general rate case filing for Narragansett Electric reasonably in advance of such filing.

ii. The allocation of the annual base distribution rate allowance of the revenue requirements associated with Grid Modernization programs and Special Sector Programs, as described in Sections 15 and 20, respectively, and the Rate Year 2 and Rate Year 3 annual base distribution rate increases as stated above in Section 4.

The Settling Parties agree with Narragansett Electric's rate design included in Attachment 9, which reflects:

i. The Rate A-16/Rate A-60 rate design reflects a monthly customer charge of $6.00 and a base distribution per-kWh rate sufficient to recover the remaining Rate A-16/Rate A-60 revenue requirement after consideration of the $6.00 customer charge.

ii. The Rate A-60 customer charge shall be phased-in over the term of the Rate Plan as proposed by the Company in its initial filing as follows: a customer charge of $2.00 effective September 1, 2018; a customer charge of $4.00 effective September 1, 2019; and a customer charge of $6.00 effective September 1, 2020.

iii. The Rate C-06 rate design reflects a monthly customer charge of $10.00 and a base distribution per-kWh rate sufficient to recover the remaining Rate C-06 revenue requirement after consideration of the $10.00 customer charge.

iv. The Rate G-32 rate design reflects impact of the results of the ACOSS submitted on May 9, 2018 in Schedule HSG-1A(R) which redefines transmission level voltage to be electric service received at no less than 69 kV.

c. *Other Settlement Provisions*. The Settling Parties agree to the following:

i. For customers receiving delivery service on Rate A-60, a total bill discount shall be applied. Specifically, (a) the percentage discount off of the total amount billed shall be 25 percent, and (b) for customers receiving benefits through Medicaid, General Public Assistance, and/or the Family Independence Program, an additional discount of 5 percent off of the total amount billed. The Settling Parties agree that Narragansett Electric shall implement the Low Income Discount Recovery Factor (LIDRF) calculated in Attachment 20. Customers billed on Rate A-60 shall not be assessed the LIDRF.

ii. A revision to the Credit for High Voltage Delivery (HVD) provision contained in the Large Demand Rate (G-32) retail delivery service tariff (Rate G-32 Tariff) and Large Demand Backup Service Rate (B-32) retail delivery service tariff (Rate B-32 Tariff) that defines transmission level voltage to be electric service at no less than 69 kV.

iii. The Fox Point Hurricane Barrier (Hurricane Barrier) operated by the United States Army Corps of Engineers (USACE)[17] is designed to protect the City of Providence from flooding and is tested periodically. The USACE has begun conducting its periodic testing of the Hurricane Barrier during off-peak hours, as defined in the Rate G-32 Tariff, to avoid the demand ratchet provision for the assessment of billing demand that would occur for testing during peak hours.

To address the concerns raised by Navy/FEA with respect to the Hurricane Barrier, if the Hurricane Barrier is operated during peak hours, as defined in the Rate G-32 Tariff, as a result of a weather event, (1) immediately following the operation of the Hurricane Barrier during peak hours, the USACE will contact the Company, in writing, notifying the Company that a weather

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[17] The USACE is represented in these proceedings by the Navy on behalf of the FEA.

event required the operation of the Hurricane Barrier; (2) after review and confirmation of the conditions at the time of the Hurricane Barrier's operation during peak hours, the Company will waive the demand ratchet provision resulting from the operation of the Hurricane Barrier during peak hours, for the 11 billing months following the month of peak hour operation (billing months 2 through 12). This waiver would be pursuant to the Rate G-32 Tariff under the Demand provision, which defined billing demand "under ordinary load conditions;" and (3) the USACE will be billed based on the billing demand as determined pursuant to the Rate G-32 Tariff based on peak hours metered demand measured in kW and kVa during the month of operation. If the USACE tests the Hurricane Barrier during peak hours, the demand ratchet of the Rate G-32 Tariff would apply for the billing of distribution demand charges in months 2 through 12. However, the USACE can avail itself of the Optional Determination of Demand provision in the Rate G-32 Tariff.

To ensure that the billing account remains on Rate G-32 as a result of the Hurricane Barrier's continued testing during off-peak hours, the Company has revised the availability provision of the Rate G-32 Tariff and the Rate B-32 Tariff to define customers eligible for Rate G-32 and Rate B-32 based on metered demand during all hours, rather than billing demand, which is determined during peak hours. This change will allow a large customer, such as the Hurricane Barrier, respond to the price signals of Rate G-32 and Rate B-32 and remain on Rate G-32 and Rate B-32, and not be transferred to the General C&I Rate (G-02) tariff.

iv. The Company shall add to Rate S-05 another operating schedule allowing customer-owned light-emitting diode (LED) streetlights to operate at an output level that would result in 3,080 annual operating hour equivalents. As this operating schedule is preferred by NERI as compared to the operating schedule Narragansett Electric presented in its

May 9, 2018 rebuttal testimony in Schedule PP-6(R), Narragansett Electric will withdraw its May 9, 2018 operating schedule proposal. In addition, for purposes of billing LED streetlights that operate at an output level that is less than the Dusk-to-Dawn operating schedule existing in the Rate S-05 tariff, the annual operating hour equivalent of such a streetlight shall be compared to the operating schedules contained in the Rate S-05 tariff. If the streetlight's annual operating hour equivalent is no more than five percent of an existing operating schedule's annual operating hour equivalent, the streetlight shall be placed on that operating schedule. If the streetlight's annual operating hour equivalent exceeds the annual operating hour equivalent of an existing operating schedule by more than five percent, the streetlight shall be placed on the operating schedule with the next highest annual operating hour equivalent.

v. The Company shall implement a returned check fee of $8.00.

vi. The Company shall cancel its Optional Telephone or Web Page Payment Provision, RIPUC No. 2154.

d. *Miscellaneous Corrections*. The Settling Parties agree that Narragansett Electric shall make all corrections (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal ACOSS and rate design, and (3) resulting from changes presented in the rebuttal testimony of Company Witness Howard S. Gorman in finalizing the ACOSS, revenue allocation, and rate design.

e. *Bill Impacts and Tariffs*. Attachment 10 sets forth the electric bill impacts resulting from this Settlement Agreement. Attachment 12 presents the other rates and charges that are impacted by this Settlement Agreement, consistent with what was initially filed on November 27, 2017. Attachment 13 contains the tariffs and tariff provisions, marked to show changes from those currently in effect, that are proposed to become effective September 1, 2018.

The impact of this Settlement Agreement on the monthly bill of a 500 kWh residential customer receiving Standard Offer Service, as compared to the rates which were in effect at the time of the Company's filing in this case, in each of the Rate Years is as follows:

	Dollar Increase	Percent Increase
Rate Year 1	$3.67	3.5%
Rate Year 2	$1.03	0.9%
Rate Year 3	$0.44	0.4%

6. Narragansett Electric - Earnings Report and Earnings Sharing Mechanism

a. *Annual Earnings Report*. The Company shall file with the PUC and the Division annual earnings reports for Narragansett Electric consistent with and in a form similar to that which the Company has been filing for several years, most recently in Docket No. 4323, calculating electric regulatory earnings for the calendar year with the additions/changes set forth in subsections b. through d. below. The timing of the filing of the annual earnings report for Narragansett Electric shall be May 1 of each year.

b. *Definitions*.

i. **"Actual Earnings"** means earnings including all Performance Incentives earned for the applicable calendar year.

ii. **"Base Earnings"** means earnings excluding all Performance Incentives earned for the applicable calendar year. The Base Earnings calculation also shall exclude any financial penalties incurred by Narragansett Electric that may have been assessed by the PUC or the Division during the calendar year, and the report shall disclose those excluded amounts separately.

iii. **"EE Performance Incentive"** means the Energy Efficiency Program (EEP) Incentive.

iv. **"Performance Incentives"** means the EE Performance Incentive; any earned System Reliability Procurement incentives; LTCR Remuneration Costs; RE Growth Remuneration Costs; Performance Incentive Mechanisms Incentives; and any other performance incentive that has been or may be approved by the PUC in a future proceeding and that was earned and recorded by Narragansett Electric for performance applicable to the calendar year.

v. **"Performance Incentive Mechanisms Incentives"** means the incentives earned from the incentive mechanisms as set forth in Section 19 of this Settlement Agreement.

c. *Calculation of Earnings for Annual Earnings Report*. The Company shall show the calculation of the regulatory earned return on distribution rate base and the earned return on distribution common equity, in two ways:

i. Actual Earnings for the applicable calendar year; and

ii. Base Earnings for the applicable calendar year.

d. *Earnings Sharing With Customers*. If and when the Base Earnings exceed the allowed ROE of 9.275 percent in any calendar year, the amount in excess of 9.275 percent will be deemed "shared earnings."

i. If the level of earnings is greater than the allowed ROE of 9.275 percent, but is less than or equal to 10.275 percent, 50 percent of the shared earnings in this tier shall be credited to customers and the Company shall retain 50 percent of the shared earnings, which shall not be reflected in any earnings reports.

ii. If the level of earnings is greater than 10.275 percent, 75 percent of the shared earnings in this tier shall be credited to customers and the Company shall retain 25 percent of the shared earnings, which shall not be reflected in any earnings report.

Narragansett Electric shall retain 100 percent of any excess earnings of the Actual Earnings that are attributable to any of the Performance Incentives. Any shared earnings credited to customers shall be credited to the Storm Fund, unless the PUC otherwise directs the credit to customers in another manner.

7. Narragansett Electric - Other Tariffs and Reconciling Mechanisms

The Settling Parties agree that this Settlement Agreement does not (and is not intended to) amend, modify, or change in any respect any tariff or mechanism currently in effect for Narragansett Electric for costs recovered outside of base distribution rates pursuant to any statute or prior PUC order that is not specifically addressed in this Settlement Agreement, or contained in Attachment 22.

Consistent with the impact of the results of a general rate case and the PUC's rulings thereon, the Company shall implement changes to its other factors and charges associated with its various reconciling mechanisms, effective September 1, 2018, to reflect updated net write off percentages, WACCs, and consolidation of Rate G-32 and Rate G-62. In its compliance filing pursuant the PUC's approval of the Rate Plan, the Company shall file schedules in support of the requisite changes to its other factors and charges that will be reflected in its bills to customers effective September 1, 2018, as illustrated in Attachment 12.

8. Narragansett Gas - Revenue Requirement

a. *Revenue Requirements for the Rate Years*. This Settlement Agreement provides that base distribution rates for Narragansett Gas shall be set in these proceedings based on a Rate Year 1 revenue requirement increase of $5.7 million, a Rate Year 2 revenue requirement increase of $7.6 million, and a Rate Year 3 revenue requirement increase of $4.0 million, using a test-year ended June 30, 2017, as detailed in Attachment 2 to this Settlement Agreement. The resulting revenue requirements for the Rate Years are: $218.6 million for RY1, $226.2 million for RY2, and $230.2 million for RY3. The revenue requirement for Rate Year 1 was determined using a total rate base of $760.6 million; pro forma Test Year operating revenues of $212.8 million; distribution operating expenses of $86.1 million; income taxes of $5.7 million; and an overall rate of return of 7.15 percent. The revenue requirement for Rate Year 1 established by the Settling Parties allows for recovery of a revenue deficiency of $5.8 million in Rate Year 1, which represents a reduction of $24.4 million from the November 27, 2017 original request and a reduction of $9.6 million from the May 9, 2018 second revision to the cost of service.

As noted in Attachment 23 , the Company will credit the Net Revenue received for Narragansett Gas storm response services performed in other jurisdictions, including those outside of National Grid USA operating companies' service territories, back to customers through the Distribution Adjustment Charge, applicable.

b. *Calculation of Rate Base*. The Settling Parties agree that rate base for Narragansett Gas for the Rate Years shall be calculated to include capital additions approved in the ISR plans for Fiscal Year 2014 (Docket No. 4380), Fiscal Year 2015 (Docket No. 4474), Fiscal Year 2016 (Docket No. 4540), Fiscal Year 2017 (Docket No. 4590), and estimated Fiscal

Year 2018 (Docket No. 4678), estimated Fiscal Year 2019, and estimated Fiscal Year 2020 additions through Rate Year 1 (*i.e.*, August 31, 2019).[18] Narragansett Gas' rate base for the Rate Years also shall be calculated to include non-ISR capital additions through August 31, 2021. The Narragansett Gas rate base also shall reflect the unamortized cost of the long-term debt issuance expense. ISR-eligible capital additions for Rate Year 2 and Rate Year 3 will be addressed in the ordinary course outside of base distribution rates through the ISR and included for recovery in future ISR Plans.

c. *Other Adjustments.* The revenue requirements contained in Attachment 2 reflect adjustments agreed to by the Settling Parties associated with the Tax Cuts and Jobs Act, a change in the Company's A&G capitalization policy, and estimated Service Company excess deferred federal income taxes.

d. *Operating Expenses*

i. Uncollectible Accounts Expense

The Settling Parties agree that the recovery of distribution-related uncollectible-accounts expense[19] shall be calculated using Narragansett Gas's actual five-year average ratio of actual distribution net write-offs as a percentage of distribution revenues (as calculated in Docket No. 4323 and Docket No. 3943) ending with the Test Year, except as follows:

> The twelve-month period ended June 30, 2013 will be eliminated from this calculation for Narragansett Gas for the Rate Year(s) in these proceedings. This adjustment reduces the average write-off rate that is applied to the Rate Year 1

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[18] Capital additions that are being recovered currently through the ISR will be included in rate base as of September 1, 2018, concurrent with the effective date of new base rates in these proceedings. Therefore, the capital-related portion of the ISR factor will be set to zero as of September 1, 2018.

[19] This amount does not include the commodity-related portion of uncollectible accounts expense (see Pre-Filed Direct Testimony of Company Witness Melissa A. Little at Page 47 (Bates Page 51 of Book 8). The calculation of uncollectible account expense is provided in Schedule MAL-22 (Rev-2) (Rebuttal Book 3).

revenues to calculate the pro forma Rate Year 1 uncollectible accounts expense. This adjustment reduces the average Narragansett Gas write-off rate from 2.08 percent to 1.91 percent.

The write-off rate of 1.91 percent also shall be used to calculate the uncollectible accounts expense allowance in those reconciling mechanisms that provide for the recovery of uncollectible account expense.

e. *Return on Rate Base*

i. Capital Structure

The Settling Parties agree that the revenue requirement established by this Settlement Agreement for Narragansett Gas shall be set, as shown on Attachment 2. The actual capital structure shall be adjusted further to include the long-term debt issued on July 27, 2018 pursuant to the separate Settlement Agreement entered into between the Division and the Company dated February 15, 2017, in Division Docket D-17-36, which was approved as set forth in the Division's Report and Order issued February 19, 2017, and as set forth in the statement of basic terms that the Company filed with the Division on August 1, 2018.

ii. Cost of Long-Term Debt

As stated above, the new long-term debt shall be pro-formed at an interest rate of 3.919 percent and debt expense estimated at 0.46 percent, or $1.61 million. Upon completion of the debt issuance, the revenue requirement established by the Settlement Agreement shall be adjusted to use the actual weighted cost of long-term debt and debt expense after the new debt issuance. The Company shall make a filing to the PUC within 60 days of the completion of the issuance to adjust base distribution rates to incorporate the actual debt rate and issuance costs in distribution rates.

iii. Return on Common Equity

The Settling Parties agree that the return on common equity shall be set at 9.275 percent.

iv. Weighted Average Cost of Capital

The computation of the pre-tax WACC established by this Settlement Agreement is set forth in Attachment 2. The weighted average cost of capital set forth in Attachment 2, as adjusted pursuant to Section 8(e), above, shall be used for ratemaking purposes, including in the ISR Plan, until the next base-distribution rate proceeding for Narragansett Gas.

f. *Miscellaneous Corrections*. The Settling Parties agree that Narragansett Gas shall make all corrections (1) identified during discovery, (2) in the preparation of the May 9, 2018 rebuttal cost of service, and (3) resulting from changes presented in the rebuttal testimony of Company Witness Melissa A. Little in finalizing the cost of service for Narragansett Gas.

9. Narragansett Gas - Revenue Allocation, Rate Design, and Tariff

a. *Allocated Cost of Service*. The Settling Parties agree, for the purpose of settlement in these proceedings, to use the ACOSS included in Attachment 14, consistent with the ACOSS filed by Narragansett Gas on April 3, 2018.

b. *Revenue Allocation and Rate Design*. The Settling Parties agree that Narragansett Gas' revenue allocation contained in Attachment 16, prepared consistent with the Division's recommended revenue allocation filed with the PUC on April 6, 2018,[20] shall be incorporated into the design of base distribution rates. The Settling Parties agree to the allocation of the annual base distribution rate allowance of the revenue requirements associated with Grid Modernization programs allocable to Narragansett Gas, as described in Section 15, and

[20] Schedule BRO-4 of the Direct Testimony of Witness Bruce R. Oliver on behalf of the Division.

the Rate Year 2 and Rate Year 3 annual base distribution rate increases as stated above in Section 8.

The Settling Parties agree with Narragansett Gas' rate design included in Attachment 16, which reflects:

i. The rate designs for Rates 10/11 and Rates 12/13 reflect a monthly customer charge of $14.00 and uniform base distribution per-therm rates sufficient to recover the remaining revenue requirement of these two rate classes after consideration of the $14.00 customer charge.

ii. The rate designs for Rates 10/11 and Rates 12/13 reflect different uniform base distribution per-therm rates effective during the peak months of November through April as compared to uniform base distribution per-therm rates effective during the non-peak months of May through October.

iii. The rate design for Rate 21 reflects a monthly customer charge of $25.00 and uniform base distribution per-therm rates sufficient to recover the remaining revenue requirement of these two rate classes after consideration of the $25.00 customer charge.

iv. The rate designs for Rate 21 reflects different uniform base distribution per-therm rates effective during the peak months of November through April as compared to uniform base distribution per-therm rates effective during the non-peak months of May through October.

c. *Other Settlement Provisions*. The Settling Parties agree to the following:

i. For customers receiving delivery service on Rates 11 and 13, a total bill discount shall be applied. Specifically, (a) the percentage discount off of the total amount billed shall be 25 percent, and (b) customers receiving benefits through Medicaid, General Public Assistance, and/or the Family Independence Program, an additional discount of 5 percent off the total amount billed. The Settling Parties agree that Narragansett Gas shall implement the LIDRF calculated in Attachment 20. Customers billed on Rates 11 or 13 shall not be assessed the LIDRF.

ii. The Company shall implement a returned check fee of $8.00.

iii. Narragansett Gas shall remove the Optional Credit Card Payment Provision from its tariff.

iv. Narragansett Gas will weather-normalize the demand billing units of its medium, large, and extra-large commercial and industrial rate classes in future general rate cases.

v. Narragansett Gas shall revise the language in the Distribution Adjustment Clause of its tariff to clarify the determination of System Pressure costs consistent with the Division's recommendation.

vi. Narragansett Gas shall revise the language in the Gas Cost Recovery (GCR) Clause of its tariff that will allow for it to include in its annual GCR factor filings an estimate of operation and maintenance (O&M) expense associated with its liquefied natural gas (LNG) activities as a component of fixed gas supply costs. This estimate is subject to reconciliation to actual LNG O&M expense incurred during the applicable GCR factor term, subject to the PUC's review of reasonableness and prudency, consistent with the other fixed gas supply costs, which also are subject to the PUC's review and approval. The implementation of this change in ratemaking treatment of LNG O&M expense is intended to capture any decreases in LNG O&M expense noted by the Division in its April 6, 2018 direct testimony. The amount of LNG O&M expense can be lower or higher than the amount removed from the Rate Year 1 distribution revenue requirement. The proposed revisions to the GCR Clause are included in Attachment 19.

d. *Miscellaneous Corrections*. The Settling Parties agree that, in finalizing the ACOSS, revenue allocation, and rate design, Narragansett Gas shall make all corrections identified during discovery.

e. *Bill Impacts and Tariff*. Attachment 17 sets forth the gas bill impacts resulting from this Settlement Agreement. Attachment 18 presents the other rates and charges that are impacted by this Settlement Agreement, consistent with what was initially filed on November 27, 2017. Attachment 19 contains the tariff, marked to show changes from that currently in effect, proposed to become effective September 1, 2018.

The impact of this Settlement Agreement on the annual bill of an 845 therm residential heating customer, as compared to the rates which were in effect at the time of the Company's filing in this case, in each of the Rate Years is as follows:

	Dollar Increase (Decrease)	Percent Increase (Decrease)
Rate Year 1	($10.78)	(0.9%)
Rate Year 2	$23.01	1.9%
Rate Year 3	$11.94	1.0%

10. Narragansett Gas - Earnings Report and Earnings Sharing Mechanism

a. *Annual Earnings Report*. The Company shall file with the PUC and the Division annual earnings reports for Narragansett Gas consistent with and in a form similar to that which the Company has been filing for several years, most recently in Docket No. 4323, calculating gas regulatory earnings for the calendar year with the additions/changes set forth in subsection b. below. The timing of the filing of the annual earnings report for Narragansett Gas shall change from September 1 to May 1 each year to align with the timing of the filing of the Company's earnings report for Narragansett Electric on May 1 of each year. The Company's Annual Report to the PUC for Narragansett Gas will reflect the twelve-month period ending December 31. The Company will file its gas earnings report for Fiscal Year 2018 on or before September 1, 2018. The Company will file its first gas earnings report for the twelve-month period ending December 31, 2018 by May 1, 2019.

b. *Calculation of Earnings for Annual Earnings Report*. The Company shall show the calculation of the regulatory earned return on distribution rate base and the earned return on distribution common equity, in two ways:

i. Earnings including all Performance Incentives (as hereinafter defined below) earned for the applicable calendar year (Actual Total Earnings); and

ii. Earnings excluding all Performance Incentives earned for the applicable calendar year (Base Earnings). The Base Earnings calculation also shall exclude any financial penalties incurred by Narragansett Gas that may have been assessed by the PUC or the Division and recorded during the calendar year, and the report shall disclose those excluded amounts separately.

For purposes of this Section, the term "Performance Incentives" refers to each of the following incentives:

i. Energy Efficiency Program (EEP) incentive;

ii. The Company's share of any incentive earned pursuant to the Natural Gas Portfolio Management Plan recorded during the calendar year;

iii. The Company's share of any incentive earned or penalties incurred pursuant to the Gas Procurement Incentive Plan recorded during the calendar year; and

iv. Any other performance incentive that may be approved by the PUC in a future proceeding that was earned and recorded by Narragansett Gas for performance applicable to the calendar year, unless the PUC determines at the time of approval that any such future incentive should be included in the calculation of Base Earnings.

For informational purposes, the Company shall include a separate calculation of the basis point value on the earned return on distribution common equity resulting from and for each of the individual Performance Incentives.

c. *Earnings Sharing With Customers*. If and when the Narragansett Gas Base Earnings exceed the allowed ROE of 9.275 percent in any calendar year, the amount in excess of 9.275 percent will be deemed "shared earnings."

i. If the level of Base Earnings is greater than the allowed ROE of 9.275 percent but is less than or equal to 10.275 percent, 50 percent of the shared earnings in this tier shall be credited to customers and the Company shall retain 50 percent of the shared earnings, which shall not be reflected in any earnings reports.

ii. If the level of Base Earnings is greater than 10.275, 75 percent of the shared earnings in this tier shall be credited to customers and the Company shall retain 25 percent of the shared earnings, which shall not be reflected in any earnings reports.

Narragansett Gas shall retain 100 percent of any excess gas earnings of the Actual Total Earnings that are attributable to any of the Performance Incentives. Any shared gas earnings credited to customers shall be credited to the Distribution Adjustment Clause (DAC), unless the PUC otherwise directs the credit to customers in another manner.

11. Narragansett Gas - Other Tariffs and Reconciling Mechanisms

The Settling Parties agree that this Settlement Agreement does not (and is not intended to) amend, modify, or change in any respect any tariff or mechanism currently in effect for Narragansett Gas for costs recovered outside of base distribution rates pursuant to any statute or prior PUC order that are not specifically addressed in this Settlement Agreement, or contained in Attachment 22.

Consistent with the impact of the results of a general rate case and the PUC's rulings thereon, the Company shall implement changes to its other factors and charges associated with its various reconciling mechanisms, effective September 1, 2018, to reflect updated net write off percentages, LNG O&M expense, WACCs, and cash working capital percentages. In its compliance filing pursuant the PUC's approval of the Rate Plan, the Company shall file schedules in support of the requisite changes to its other factors and charges that will be reflected in its bills to customers effective September 1, 2018, as illustrated in Attachment 18.

12. Gas Business Enablement Program

a. *Program Scope; Service Company Rents; Overall Capital Investment*. The Company will continue to implement the Gas Business Enablement Program during the term of the Rate Plan. The Gas Business Enablement Program is a shared investment across all National Grid USA operating companies, which will be implemented and owned by the National Grid USA Service Company, Inc. (Service Company), with a portion of the costs allocated to the Company. The total Service Company costs of the Gas Business Enablement Program for capital expenses and project operating expenses relating to the capital investment (excluding run the business costs) are forecasted to be $478.3 million through Fiscal Year (FY) 2023.

b. *Capital Investment Levels for the Company*. The revenue requirements for Narragansett Electric and Narragansett Gas include 85 percent of the Company's share, as charged to the Company by the Service Company as a rent expense, of the annual revenue requirement on forecasted Gas Business Enablement Program capital investments. The rent expense charged to the Company for the Gas Business Enablement Program includes the return on, and the amortization of, the Company's allocated portion of current Gas Business Enablement Program capital investments along with incremental Gas Business Enablement Program capital investments that are forecasted to be placed in service during the Rate Years. Notwithstanding the specified program level spending amounts, nothing in this Settlement Agreement is intended to alter the Company's flexibility during the term to substitute, change, or modify the timing of its Gas Business Enablement Program capital investments to deliver the scope of the Gas Business Enablement Program.

c. *10-Year Amortization of Operating and Maintenance (O&M) Costs for the Company*. The revenue requirements for Narragansett Electric and Narragansett Gas for each Rate Year include 85 percent of the Company's forecasted annual non-recurring O&M expense for the Gas Business Enablement Program to be charged to the Company during each Rate Year, amortized over 10 years and including a return at Narragansett Electric's and Narragansett Gas's WACC, as applicable. The revenue requirements include a reduction to the non-recurring O&M expense allowance in each Rate Year, representing 100 percent of Type I forecasted O&M savings and 85 percent of Type II forecasted O&M savings expected to be realized as a result of the Gas Business Enablement Program.

d. *Run-the-Business Costs.* The revenue requirements include forecasted incremental costs to maintain the Gas Business Enablement technology in the Rate Years at the level proposed by the Company in its initial filing: $779,580, $1.2 million, and $1.3 million, respectively, for Narragansett Gas. In the Company's initial request, it included an offset to these run-the-business costs representing 100 percent of Type I forecasted O&M savings. As part of the settlement, the Company has agreed to further offset these costs by an amount representing 85 percent of Type II forecasted O&M savings expected to be realized as a result of the Gas Business Enablement Program. The adjustment to reflect these additional savings result in a reduction to the revenue requirement of $49,823, $157,867, and $265,584 in each Rate Year, respectively.

e. *Deferral*. To the extent the Company incurs costs less than the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 12.b. and 12.c. above, the Company shall create a regulatory liability to defer that amount to be returned to customers. The credit to customers of the balance of the regulatory liability account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. To the extent the Company incurs costs in excess of the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 12.b. and 12.c. above, the Company shall create a regulatory asset to defer that amount, but in no case will the deferral to the regulatory asset result in recovery of a total cost in excess of the Company's forecasted revenue requirement allowances included in base distribution rates for the items described in Section 12.b. and Section 12.c. above, of $43.8 million ($38.3 million for Narragansett Gas and $5.5 million for Narragansett Electric). The recovery of the balance of the regulatory asset account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. All Gas Business Enablement costs to be recovered shall be subject to the PUC's review of the reasonableness and prudency of such costs. The Company will accrue carrying charges on the deferral balances using the pre-tax WACC.

f. *Gas Business Enablement Program Reporting*. The Company will file quarterly Gas Business Enablement Program reports with the PUC and the Division within 60 days after the end of each quarter of each Rate Year. The report will address the status of the Gas Business Enablement Program and budget, including: (i) a narrative explaining overall program status; (ii) detail on budgets and actual spending; (iii) identification of allocations of costs to the Company; (iv) explanations of variances between budgeted and actual spending; and (v) an update on the status of the deferral balance created pursuant to subsection e. above, including, at a minimum, the increase, decrease, and balance of the deferral at the end of each quarter.

The Company will work with the Division to accommodate more in-depth reviews by the Division, PUC Staff, or the Division's consultants of the systems associated with Gas Business Enablement during the term of the Rate Plan.

13. Cyber Security and Information Services (IS) Technology Modernization Programs

a. *Scope of Programs; Service Company Rents; Overall Capital Investment*. The Company will continue to implement the Cyber Security and IS Technology Modernization Programs during the term of the Rate Plan. The Cyber Security and IS Technology Modernization Programs are shared investments across all National Grid USA operating companies, which will be implemented and owned by the Service Company, with a portion of the costs allocated to the Company. The total Service Company costs of the Cyber Security and IS Technology Modernization Programs for capital investments and project operating expenses relating to the capital investment (excluding run the business costs) are included in the revenue requirement.

b. *Capital Investment Levels for the Company*. The revenue requirements for Narragansett Electric and Narragansett Gas include 85 percent of the Company's share, as charged to the Company by the Service Company as rent expense, of the annual revenue requirement on forecasted Cyber Security and IS Technology Modernization Programs capital investments. The rent expense charged to the Company for the Cyber Security and IS Technology Modernization Programs includes the return on, and the amortization of, the Company's allocated portion of current Cyber Security and IS Technology Modernization Program capital investments and incremental Cyber Security and IS Technology Modernization Programs capital investments that are forecast to be placed in service during the Rate Years. Notwithstanding the specified program level spending amounts, nothing in this Settlement Agreement is intended to alter the Company's flexibility during the term to substitute, change, or modify the timing of its Cyber Security and/or IS Technology Modernization Programs capital investments to deliver the scope of the Cyber Security and/or IS Technology Modernization Programs.

c. *Deferral*. To the extent the Company incurs costs less than the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 13.b. above, the Company shall create a regulatory liability to defer that amount to be returned to customers. The credit to customers of the balance of the regulatory liability account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. To the extent the Company incurs costs in excess of the Narragansett Electric and Narragansett Gas revenue requirement allowances included in base distribution rates for the items described in Section 13.b. above, the Company shall create a regulatory asset to defer that amount, but in no case will the deferral of the regulatory asset result in recovery of a total cost in excess of the Company's forecasted revenue requirement of $17.3 million ($5.2 million for Narragansett Gas and $12.1 million for Narragansett Electric). The recovery of the balance of the regulatory asset account shall be determined from the Company's next general rate case or extension of the Rate Plan governed by this Settlement Agreement. All Cyber Security and IS Technology Modernization Program costs to be recovered shall be subject to the PUC's review of the reasonableness and prudency of such costs. The Company will accrue carrying charges on the deferral balances using the pre-tax WACC.

d. *Cyber Security and IS Technology Modernization Programs Reporting*. The Company will file quarterly Cyber Security and IS Technology Modernization Programs reports with the PUC and the Division within 60 days after the end of each quarter of each Rate Year. The report will address the status of the Cyber Security and IS Technology Modernization Programs and budgets, including: (i) a narrative explaining overall program status; (ii) detail on budgets and actual spending; (iii) identification of allocations of costs to the Company; (iv) explanations of variances between budgets and actual spending, and (v) an update on the status of the deferral balance created pursuant to subsection c. above, including, at a minimum, the increase, decrease, and balance of the deferral at the end of each quarter. In the report for the last quarter of each Rate Year (quarter ending March 31), the Company will also include (i) any cost or timeline differences that exceed ten percent for the Rate Year; and (ii) the latest Cyber Security and IS Technology Modernization Programs sanction papers authorized during that Rate Year.

The Company will work with the Division to accommodate more in-depth reviews by the Division, PUC Staff, or the Division's consultants of these programs during the term of the Rate

Plan. The Company commits to submit to the Division and PUC the report produced by the independent cyber security consultant who reviewed the Company's cyber security investments and strategy no later than 30 days after the approval of the Settlement Agreement. The report will be filed under the protection of confidentiality.

14. Commencement of Investments to Enable a Modern Grid

The Company shall commence implementation of the following initiatives that the Company originally identified in its PST Plan filing in Docket No. 4780, as provided below:

a. *System Data Portal*

Narragansett Electric will implement this project beginning in Rate Year 1. The revenue requirement in Rate Year 1 will include \$0.5 million for up to two FTEs in support of this project; the revenue requirement in Rate Year 2 will include an incremental \$0.2 million for one additional FTE in Rate Year 2.

b. *Control Center Enhancements*

i. Geographic Information System (GIS) Data Enhancement Project

Narragansett Electric will commence the GIS Data Enhancement Project, as proposed in its initial filing, in Rate Year 1, and will use reasonable efforts to complete it within 12 months after the project is commenced. The Company's allocated share of the GIS Data Enhancement Project is \$427,000, which will be amortized over the three years of the MRP and included in Narragansett Electric's revenue requirement, with a return at the customer deposit rate. Narragansett Electric will commence populating the system with Rhode Island information in Rate Year 2. An allowance of \$1 million will be included in the revenue requirements for Rate Year 2 and Rate Year 3 for this project.

ii. Distribution Supervisory Control and Data Acquisition (DSCADA) and Advanced Distribution Management System (ADMS)

Narragansett Electric shall begin the DSCADA/ADMS project, as proposed in its initial filing, during the MRP. To provide Narragansett Electric an opportunity to coordinate implementation of DSCADA/ADMS with its Massachusetts affiliates, Narragansett Electric shall have the discretion to determine the commencement date of the DSCADA/ADMS project. An allowance for the Company's multi-jurisdictional share of the DSCADA/ADMS project in an amount of $0.4 million to cover the initial costs for project Requirements and Definition will be included in the revenue requirement in Rate Year 2. If, however, the DSCADA/ADMS project commences on a later schedule during the MRP, the allowance shall be deferred and applied to the cost of the project, regardless of the timing of completion, and the deferral of which will accumulate interest at the customer deposit rate. A three-year project development and deployment phase will then commence with an expected in-service date beyond the term of the MRP; therefore, revenue requirements for the deployment are not included in this plan.

iii. Remote Terminal Unit (RTU) Separation

Narragansett Electric will begin a program to separate distribution RTUs from transmission RTUs in support of DSCADA/ADMS. Distribution system data will be disaggregated from transmission system data by separating the field RTUs that capture the data and incorporating it into the Company's Supervisory Control and Data Acquisition (SCADA) system. In addition to enabling dedicated DSCADA, a secondary benefit from creating a bright line separation between transmission operations and distribution operations is that it eliminates FERC Critical Infrastructure Protection (CIP) oversight, and its associated risks and costs, from distribution operations. Allowances of $0.0 million, $0.2 million, and $0.3 million are included in Rate Year 1, Rate Year 2, and Rate Year 3 revenue requirements, respectively, for RTU investments.

c. *Other Grid Modernization Investments*. In addition to these foundation initiatives, the following IS-related grid modernization investments are included in the Rate Year 2 and Rate Year 3 revenue requirements: Enterprise Service Bus, Data Lake, PI Historian, Advanced Analytics, Telecommunications, and Cybersecurity.

15. Grid Modernization Plan (GMP)

a. Narragansett Electric will engage with stakeholders via the PST Advisory Group or relevant subcommittee, to develop a comprehensive Grid Modernization Plan (GMP), in parallel with the collaborative effort to develop the Updated AMF Business Case. The GMP will provide a full assessment of the various initiatives being contemplated, including an explanation and evaluation of how the initiatives link to each other. The assessment will consider short and long-term initiatives to include active and future programs. The GMP will present implementation plans outlining the details and technologies over a five-year horizon plus an outline of how this plan aligns with the longer term (i.e., a ten year roadmap). The GMP will provide a roadmap of potential investments beyond the term of the current MRP; requests to fund those investments will be included as part of a general rate case, MRP, or ISR Plan filings.

b. Narragansett Electric will file the GMP with the PUC within a reasonable time after, or in conjunction with, the filing of the Updated AMF Business Case, as described in Section 16, below, but in any event no later than six (6) months following the filing of the Updated AMF Business Case to allow the PUC to consider the GMP and Updated AMF Business Case together.

c. The GMP will take into account the time period for any proposed AMF implementation, and it will include, at a minimum:

i. Objectives for the electric grid to advance the Goals for the Energy System and Rate Design Principles, and potential visibility requirements of the benefit-cost framework in Docket 4600 Guidance Document.

ii. Explanation of the role of currently active programs;

iii. Investments and technology deployments planned through the end of any proposed AMF implementation;

iv. Functionalities to achieve those objectives;

v. Review of options for candidate technologies to deliver those functionalities;

vi. Transparent, updated benefit cost analyses that fully incorporate the Docket No. 4600 framework;

vii. An implementation plan that provides a detailed explanation of the prioritization, sequencing, and pace of investments;

viii. A plan and explanation for the integration and leveraging of customer-side technologies and resources in the near and long-term;

ix. Identification of the possible communications solutions that address current and future needs and support a wide array of potential grid modernization programs and activities;

x. Explanation of congruency with grid modernization activities in New York and Massachusetts;

xi. A plan and explanation of how the selected investments and implementation plan address risks of redundancy or obsolescence; and

xii. A description of how the GMP, in particular the distribution planning components, addresses the relationship between electrification of heating and transportation and energy efficiency to allow for the furtherance of overall reduced peak demand while also encouraging electrification of heating and transportation.

d. The Settling Parties recognize that the Company's GMP and associated Company proposals will be subject to consideration by the PUC in a separate docket in conjunction with the Updated AMF Business Case, and all interested parties will have an opportunity to participate in any such docket prior to PUC action on the GMP and proposals contained therein. The Settling Parties acknowledge and agree that the PUC will make a final determination on whether and how to implement the GMP.

e. To the extent it is determined by the PUC that implementation of any grid modernization initiatives not already funded in the MRP should move forward, and Narragansett Electric must begin to incur costs during the MRP to begin the implementation process, the MRP may be re-opened to include the revenue requirement for any such approved initiatives during the term of the MRP in base distribution rates, as approved by the PUC.

16. AMF

a. *Updated AMF Business Case.* Provided this Settlement Agreement is approved by the PUC, the Company will commence the next phase of work to refine and update its AMF business case (referred to herein as the Updated AMF Business Case) for the Company's proposed AMF investments. Design and procurement efforts undertaken during that phase will be in coordination with the development of a similarly updated AMF business case for the Company's New York affiliate as part of a collaborative with the New York Public Service Commission Staff and other interested parties in that jurisdiction. The Company will use reasonable efforts to file the Updated AMF Business Case for Rhode Island with the PUC no later than February 1, 2019, which will include an evaluation of shared communications infrastructure and various ownership models for key AMF components, including the potential for incremental revenue that might be generated by these models in the future. Furthermore, the Updated AMF Business Case will address data governance regarding customer, non-regulated power producer (NPP), and third party access to system and customer data, with the proper privacy and security protections in place. The Updated AMF Business Case will propose to implement AMF in the most cost-effective way, and will provide a cost estimate that can be relied upon for purposes of establishing future revenue requirements for deployment of AMF in Rhode Island.

The Company's share of the costs to develop the Updated AMF Business Case is forecasted to be approximately $2 million. An allowance for this forecasted cost is included in the revenue requirements, which will be spread evenly over the three years of the MRP.

b. *Stakeholder Process and Regulatory Filing*. The Company will convene a preliminary meeting with Division staff and the Office of Energy Resources (OER) to develop a common understanding of the next phase of work, to identify areas of the current AMF business plan (as filed in Docket No. 4780, Book One, Chapter 4) requiring further exploration or refinement, and to identify areas for input from the PST Advisory Group (as defined in Section 17(e) below), or relevant subcommittee. An output of this preliminary meeting of the Company, the Division, and OER will be a document to formally agree on additional areas of exploration, pending the PUC's approval of the Company's $2 million funding request for the Updated AMF Business Case. The schedule for the phase of work starting August 1, 2018 and concluding February 1, 2019 with the filing of the Updated AMF Business Case is further discussed below:

i. Between August 1, 2018 and November 15, 2018, the Company will refine and update its AMF business case. As part of this process, the Company will engage stakeholders, via the PST Advisory Group, or relevant subcommittee, to explore and develop a common understanding of specific AMF proposal areas, a customer engagement plan for AMF, including the role of non-regulated power producers (NPP), and assumptions and rationale upon which a proposal to develop time varying rates will be based.

ii. By September 15, 2018, the Company will convene a second meeting with Division staff and OER to present its Updated AMF Business Case addressing stakeholder identified areas, and further discuss additional questions, comments, or proposed modifications for the Company's consideration.

iii. By October 30, 2018, the Company will convene a third meeting with Division staff and OER. At this meeting, the Company will seek clarification, as required, of stakeholder concerns and comments on the Company's Updated AMF Business Case, and provide new information, if any, to address stakeholder concerns and comments.

iv. The Company will use reasonable efforts to file the Updated AMF Business Case with the PUC for review and approval of the funding necessary to deploy statewide AMF in Rhode Island in a timeframe consistent with the Updated AMF Business Case no later than February 1, 2019. The Updated AMF Business Case will contain the following elements:

- A refined and updated AMF business plan, benefit-cost analysis (BCA), and a detailed customer engagement plan;
- An updated AMF deployment schedule with a BCA (using the Societal Cost Test) for different meter deployment periods;

- Revenue requirement for AMF deployment;
- Deployment proposals, a proposal for cost recovery of AMF, and any activities associated with implementation of AMF;
- A proposal to allocate AMF costs among rate classifications;
- Assumptions upon which a proposal to develop time varying rates will be based;
- A Data Governance Plan regarding timely customer, NPP, and third-party access to system and customer data, (e.g., elements may include, but are not limited to, customer assigned peak load contribution, energy and capacity loss factors, interval usage, or other information needed for efficient wholesale and retail market participation) in place and billing quality customer data (e.g., elements may include, but are not limited to, electric usage in kilowatt-hours containing both "register reads" and "interval reads") with the proper privacy and security protections;
- Updated costs for AMF deployment based on information gained from a procurement effort;
- Transparent, updated benefit cost analysis that fully incorporates the Docket No. 4600 framework;
- Investigation of alternative business models and ownership models;
- Analysis of data latency;
- Deployment details;
- Role of non-regulated power producers, including articles to share customer information and customer engagement;
- Ownership model for assets and telecom;

- Detailed AMF functionalities, how Rhode Island will achieve those functionalities, and a timeline for when those functionalities will be available;
- Identification of the most cost effective way to achieve the functionalities, and how the functionalities align to the policy objectives;
- Explanation of whether the realization of those functionalities will require additional future work and costs over 20 years;
- Identification of what functionalities the AMF will achieve that are part of the grid modernization plan and which are in addition to the Grid Modernization Plan;
- Identification of which functionalities are dependent on a full-scale roll out instead of a targeted roll out;
- Business cased based on both a Rhode Island-only scenario and a Rhode Island/New York scenario;
- A business case based on the length (duration) of meter deployment;
- Identification of the critically linked parts of grid modernization and AMF; and
- Identification of whether the AMF solution would allow for proper net metering according to the tariff.

The Settling Parties recognize that the Company's Updated AMF Business Case and associated Company proposals in relation to time varying rates will be subject to consideration by the PUC in a separate docket, and all interested parties will have an opportunity to participate in any process provided prior to PUC action on the Updated AMF Business Case and proposals contained therein. The Settling Parties acknowledge and agree that the PUC will make a final determination on whether and how to implement AMF and time varying rates in the Company's service territory.

c. To the extent it is determined by the PUC that deployment of AMF should move forward and the Company must incur costs during the MRP to begin the deployment process, the MRP may be re-opened to propose the revenue requirement for any such approved initiatives during the term of the MRP in base distribution rates, as approved by the PUC.

17. Clean Energy Programs

The Solar Demonstration Program for Income Eligible Customers and the Income Eligible Customer Rewards Program, originally proposed in the Company's PST Plan filing in Docket No. 4780, are hereby withdrawn. Narragansett Electric will implement a portfolio of clean energy programs in other areas that the Company originally identified in its PST Plan filing in Docket No. 4780, with some modifications to the programs, as provided below:

a. *Electric Transportation*. The Settling Parties recognize that the Company has a role in facilitating the growth of Electric Vehicle (EV) adoption and scaling of the market for EV charging equipment to advance Rhode Island's zero emission vehicles and greenhouse gas emissions policy goals. In furtherance of these goals, Narragansett Electric will implement a phased electric transportation initiative over the term of the MRP, which will be comprised of the following components: (i) Off-Peak Charging Rebate Pilot, (ii) Charging Station Demonstration Program, (iii) Discount Pilot for Direct Current Fast Charging (DCFC) Station Accounts, (iv) fleet advisory services, and (v) Electric Transportation Initiative Evaluation. The revenue requirement for this initiative will include \$0.7 million in Rate Year 1, \$1.1 million in Rate Year 2, and \$2.1 million in Rate Year 3. The costs of this initiative shall be subject to a deferral mechanism, as described in Section 20, below.

i. Off-Peak Charging Rebate Pilot

Narragansett Electric will offer an Off-Peak Charging Rebate as a pilot to reward customers for charging their EV during off-peak hours, study customer charging patterns at various charging locations and levels, understand customer responsiveness to time-differentiated price signals, and evaluate technology and partnership alternatives to monitor and report charging. Participating customers will earn a rebate for every kWh charged between 9 p.m. and 1 p.m. The off-peak charging rebate will be 6 cents per kWh during the summer months (June through September), and 4 cents per kWh in all other months. Narragansett Electric reserves the right to offer the higher rebate value in the winter months if, for example, system conditions warrant, or to otherwise modify the rebate value. Narragansett Electric will evaluate the rebate value following the first full year of the program and will include any findings and recommendations in the Annual Evaluation Report, as discussed in subsection d., below.

ii. Charging Station Demonstration Program

Narragansett Electric will demonstrate new approaches to electric charging infrastructure development. Narragansett Electric may not own any of the Level 2 charging ports (*i.e.*, charging power between 10-20 miles per hour) to be developed as part of this initiative. Narragansett Electric also may not own any of the DCFC ports to be developed as part of this initiative. Prior to Rate Year 2, Narragansett Electric may propose to re-evaluate utility ownership of Level 2 and DCFC ports as a program design modification in the Annual Program Modification Report. The proposed categories of charging stations under the program are set forth in the tables below.

Charging Station Demonstration Project: Level 2

Level 2	Total Sites	Ports Per Site	Total Ports
Workplaces	14	10	140
Apartment Buildings	6	6	36
Income Eligible Community Sites	6	6	36
Public Transit Stations	6	10	60
Government light-duty fleet	**3**	**8**	**24**
Corporate light-duty fleet	3	8	24
Total	**38**		**320**

Charging Station Demonstration Project: DCFC

DCFC	Total Sites	Ports per Site	Total Ports
Public DCFC	4	5	20
Public transit buses	2	5	10
Rideshare company charging hub	1	5	5
Other heavy-duty/DCFC (port, airport)	2	4	8
Municipal school buses	3	1	3
Total	**12**		**46**

Narragansett Electric may not act to preclude third party provider market development. This Settlement Agreement does not impose any limitations or prohibitions on non-utility product and competitive service providers from offering EV-related products and services, including charging station hardware and software, to the government light duty fleets or to site hosts located in underserved market segments.

As part of this program, Narragansett Electric will provide site hosts with the Make-Ready work necessary to host a charging station up to the costs as provided in this section. As such, Narragansett Electric will be responsible for making the site ready for charging to be installed, owned, and operated by the Site Host. For all Make-Ready sites, Site Hosts will have a choice of both EV charging equipment and network services. The Company will pre-qualify options for equipment and network services. All pre-qualified equipment will have open standards for communications and operations.

For DCFC stations, the Company will work closely with the PST Advisory Group, or relevant subcommittee, to ensure that DCFC stations deployed via this initiative are complementary to deployments using the Volkswagen Settlement Agreement funds administered by the Rhode Island Department of Environmental Management. Narragansett Electric will coordinate with OER and will reserve up to twenty-five percent (25%) of the DCFC ports to be allocated to State-funded, -supported, or -hosted stations that deliver benefits to the public. The Company will seek to co-locate one of the DCFC sites with a storage unit, as further described in subsection d. of this section, below. Deployment of the remaining DCFC sites will be in coordination with OER and the Division. For energy supply for the charging stations, the site host is the customer of record and accordingly will select competitive generation supply or standard offer service (the Company does not, and should not, have a say in the customer's decision on its choice of energy supplier).

iii. <u>Discount Pilot for Direct Current Fast Charging Station Accounts</u>

Narragansett Electric will offer a time-limited discount on the electric bills for dedicated DCFC electric accounts. This discount pilot will be available on a first come, first served basis, with the annual value limited to $300,000 per year. Any existing or new customers with General C&I Rate G-02 or Large Demand Rate G-32 for dedicated DC Fast Charging purposes will be eligible for the discount, provided that twenty five percent (25%) of the stations receiving the discount shall be in stations that enable electric public transit. The monthly bill discount will be based on a per kW credit set at the same rate as the applicable (Rate G-02 or Rate G32) distribution demand charge. The discount for participants who enroll in Rate Year 1 will be equal to one hundred percent (100%) of the distribution demand charge for a period of three years from the start of service. Sixty (60) days prior to enrollment for Rate Year 2 and Rate Year 3, the Company shall make, as part of the Electric Transportation Evaluation and Annual Program Modification Report, with input from the PST Advisory Group, a recommendation for the appropriate level of discount for new participants in such Rate Year based on enrollment data and lessons learned, for approval by the PUC. The results of the pilot and any proposed DCFC demand charges or rebates will be reviewed as part of the next MRP, which may include a phase out over years four, five, and six with the details of such phasing out to be included in the next MRP.

iv. Fleet Advisory Services

As a new component of the program arising from the settlement discussions, and not included in the Company's original filing, Narragansett Electric will, through a combination of internal and third-party expertise, offer a new advisory service to support electrification of customer fleets, the scope of which will include conducting long-term fleet electrification studies for a total of approximately twelve (12) fleet operators in Rhode Island, including government light-duty, corporate light-duty, public transit, government medium/heavy-duty (on-road and off-road), and municipal school buses. This program will replace Narragansett Electric's originally proposed Company Fleet Expansion program, which shall be eliminated, and Narragansett Electric will reallocate thirty-six percent (36%) of the funds previously identified for the Company Fleet Expansion program to fleet advisory services, provided that twenty-five percent (25%) of the funds address fleets owned by government or public transit entities.

v. Electric Transportation Initiative Evaluation

Narragansett Electric is committed to evaluating each element of the electric transportation initiative on an annual basis, and sharing its learnings with stakeholders and industry participants. In furtherance of this goal, Narragansett Electric will produce and publicly present an Annual Evaluation Report, using the metrics provided in the original filing, with appropriate modifications to be made to reflect the programs as approved in this Settlement Agreement within two months following the end of each Rate Year, describing implementation of the electric transportation initiative, and documenting the information gained through this initiative and any recommendations to enhance the program. The Company will file a copy of the Annual Evaluation Report with the PUC. The Company's Annual Evaluation Report will include, at a minimum, the following information, if available:

- location, category (as defined in the table in Section 17.a.ii. of this Settlement Agreement), in-service date, and utilization of each charging station installed;
- effectiveness of the Discount Pilot for DCFC Station Accounts, accounting for free-ridership and spillover effects;
- learnings on how the Company can integrate Electric Vehicles with minimal impacts on the cost of the distribution system, including an understanding of the effectiveness of the Off-Peak Charging Rebate Pilot;
- evaluation of the effectiveness of each component of the initiative in stimulating consumer adoption of electric vehicles, including an understanding of the effectiveness of the type and level of the incentive;

- results of the Fleet Advisory Services program, including the number of fleet vehicles converted to electric vehicles at the end of each rate year and at the end of the rate plan;
- the incremental CO_2 reductions resulting from incremental vehicle adoption as described under the Distributed Energy Resources, CO_2: Electric Vehicles metric; and
- evaluation of the Company's impact on fleet electric vehicle adoption.

The process for implementing any findings or recommendations contained in the Annual Evaluation Report will be through the PST Advisory Group, as discussed in subsection (e), below.

b. *Electric Heat.* Narragansett Electric shall not receive any funding for its proposed electric heat initiative through base distribution rates. Narragansett Electric may propose an electric heat initiative similar to the initiative proposed in this docket through the Energy Efficiency program plan, which, if proposed, will: (1) offer equipment incentives to lower the upfront cost barrier for Rhode Island residential customers to convert to efficient cold-climate air-source or ground-source heat pump systems; (2) offer rebates to a mix of standard offer service, competitive supply, and Income Eligible customers with approximately fifty percent (50%) of the rebate budget to be used for Income Eligible customers; and (3) be limited to residential customers for whom efficient electric heating has a Societal Cost Test ratio greater than 1 (e.g., currently delivered fuel customers and electric resistance customers). For standard offer service customers, the rebate level will depend on the installed system. For Income Eligible customers, the rebate level will be one hundred percent (100%) of the all-in cost of heating capacity.

c. *Strategic Electrification Education Fund.* The Settling Parties acknowledge that the ongoing electrification of transportation in Rhode Island has the potential to significantly reduce greenhouse gas emissions and to provide significant distribution system benefits. At the same time, the Settling Parties acknowledge that electric transportation, if not optimally integrated, has the potential to increase peak electric demand with negative consequences for system cost, system efficiency and emissions. To support the electric transportation initiatives discussed above, Narragansett Electric will create a Strategic Electrification Education Fund. The fund shall be administered consistent with R.I. Gen. Laws § 39-2-1.2. The revenue requirement shall include the following amounts for the fund: $7,500 in Rate Year 1 to inform customers of the availability of the off-peak charging rate; $11,250 in Rate Year 2 to inform customers of the availability of the off-peak charging rate; and $18,750 in Rate Year 3 to inform customers of the availability of the off-peak charging rate. The Settling Parties also agree that, prior to the beginning of Rate Year 2, the Company may submit, in consultation with the Division, OER, and the members of the PST Advisory Group, a revised proposal to the PUC for funding the Strategic Electrification Education Fund, consistent with R.I. Gen. Laws § 39-2-1.2. The Settling Parties agree that this provision may be severed from the remainder of this Settlement Agreement without affecting the validity of the overall settlement if the PUC deems this provision inconsistent with its motions.

d. *Energy Storage Demonstration.* The Settling Parties agree that energy storage is critical for achieving a clean energy future as it provides the ability to optimize system performance over time and allows intermittent renewable resources, such as wind and solar, to make a larger contribution to overall generation. The Settling Parties also recognize the Company has a role to effectively integrate storage. To this end, Narragansett Electric will demonstrate two energy storage solutions: (i) one behind-the-meter storage system co-located with a DCFC site, which will consist of an approximate 250 kW two hour energy storage system, supporting approximately two to six DCFC ports, and (ii) one front-of-the-meter storage system, which will consist of an approximate 500 kW three hour energy storage system for the primary purpose of realizing distribution system value, with the exact storage size and capacity to be determined by system need and location. The revenue requirement for this initiative will include $0.1 million in Rate Year 1, $0.2 million in Rate Year 2, and $0.4 million in Rate Year 3. The costs of this initiative shall be subject to a deferral mechanism, as described in Section 20, below.

Narragansett Electric will procure each storage solution through a competitive RFP process, which will set forth the technical requirements, and will request proposals for both a third party-owned system with a service agreement, and an Engineering Procurement and Construction delivered system owned by the utility, which will explore alternative ownership models on a like-for-like basis, and benefits associated with each model. Narragansett Electric will share the draft RFP with stakeholders, via the PST Advisory Group, for feedback. The Company will file each draft RFP with the PUC no fewer than 30 days before it is issued to ensure that the PUC understands the barriers the pilot demonstration is designed to overcome and the learnings the Company intends to obtain from the project. The proposal(s) that have the best value and that also are compliant with the RFP will be selected. The Company will work with the Division and OER to ensure the procurement process and selection process has been done in an independent, transparent, and fair manner. The costs included in the revenue requirement for this initiative are based on a Company ownership model. The Company will prepare a cost/benefit analysis at the conclusion of each pilot/demonstration using the Docket No. 4600

Benefit-Cost Framework.

e. *Engagement and guidance in support of PST Programs*. The Company and the Settling Parties recognize that the initiatives included in this section are new in nature, with a higher level of uncertainty about the performance and results and that delivery of these programs over the period of the MRP will benefit from broad stakeholder engagement, review, and guidance. To formalize engagement of stakeholders that will be additional to the regular engagement of the Company with the Division and OER, the Company proposes the following:

- Establishment of a "PST Advisory Group," to be chaired by the Company and whose members shall include the Division, OER, and representatives of the following interests: environment, clean energy industry or businesses, low income, NPP, community groups, and additional members as the Company, the Division, and OER may agree. The mission of the PST Advisory Group shall be to review at a high level progress on the delivery of all PST components of the MRP (Grid Modernization, AMF, time-varying rates, Electric Transportation, Storage, and Performance Incentive Mechanisms) and to provide guidance, and prioritization to support successful delivery of the components as a holistic suite. The Advisory Group shall also serve as a connection with other relevant programs / proceedings outside the MRP, for example, the Energy Efficiency Resource Management Council (EERMC), and to enable appropriate participation, alignment and coordination with such programs and proceedings.
- Creation of subcommittees under the PST Advisory Group, including but not limited to: 1) Strategic Electrification Subcommittee, and 2) AMF and Grid Modernization Subcommittee. Subcommittees shall be chaired by the Company and will include

Division and OER participation. The mission of the subcommittees shall be to provide guidance and prioritization on a more granular level in relation to the individual program.

- Quarterly updates: on a quarterly basis, commencing October 2018, the PST Advisory Group, and relevant subcommittees, will each meet to discuss the progress and challenges in the development and implementation of the PST components of the MRP, along with emerging insights and learnings. The schedule will be designed such that, wherever possible, meetings will all take place in one day, with the PST Advisory Group in the morning, followed by sequential subcommittee meetings. Prior to each quarterly meeting the Company will consult with the Division and OER to plan the agenda and topics for discussion. All PST Advisory Group members will have an opportunity to provide input on the agendas for meetings. PUC staff and Commissioners may also provide input on the agendas for topics to be addressed at PST Advisory Group meetings.
- Annual evaluation and program modification: The first PST Advisory Group meeting after the end of each Rate Year shall include a review of results and learnings from the previous year's performance. The meeting will also review recommendations for any modifications to program design or funding for the electric transportation and storage programs. The Company will file any recommendations requiring a transfer of funds between programs, following review by the PST Advisory Group, with the PUC for review and approval.
- In the event that the Company, the Division, and OER unanimously agree to adjust the schedule of meetings in the public interest, they are empowered to do so without

the agreement of all signatories to this Settlement Agreement, but they shall advise all signatories of the revised schedule.

- The Division and OER commit to leverage the guidance of the PST Advisory Group in its engagement with the Company on the development of future PST program development.
- The PST Advisory Group shall participate in two to four technical sessions or open meetings with the PUC. The PUC and all PST Advisory Group members shall have the opportunity to provide input on the creation of the agendas for these technical sessions or open meetings. The subcommittees of the PST Advisory Group shall attend and, if the PUC so directs, shall make presentations at these technical sessions or open meetings.

18. Capital Efficiency Mechanism for Narragansett Electric

The PUC is considering the Capital Efficiency Mechanism for Narragansett Electric in Docket No. 4857.

19. Performance-Based Incentive Mechanisms

The Settling Parties agree that the goal of a performance incentive mechanism is the development of meaningful performance incentives in support of key state energy policy goals. This Settlement Agreement represents a starting point for the role of performance incentive mechanisms in Rhode Island, which the Settling Parties expect will grow over time, both in terms of their financial importance and their role in driving important outcomes. Currently, the Company shall not earn any performance incentives based on values associated with unquantified benefits. The Settling Parties agree that the Division, in consultation with the Company, OER, and the members of the PST Advisory Group shall develop transparent and well-defined metrics for describing unquantified benefits and providing evidence that such unquantified benefits have been advanced, for purposes of providing a future value for a performance incentive to drive such unquantified benefits. The Settling Parties further acknowledge that the appropriate mix and definitions of performance incentive mechanisms may evolve over time as PST progresses.

Narragansett Electric will implement the following performance incentive mechanism: System Efficiency: Annual MW Capacity Savings. The System Efficiency metric includes minimum, mid, and maximum targets, with an increasing earning opportunity at each level. The Company may earn proportionally for achievements that fall between target levels up to the maximum level.[21] The potential earnings for the System Efficiency metric are calculated as 45% of the Quantified Net Benefits of achieving the metrics, as set forth in Attachment 28. The maximum earnings the Company can achieve from the System Efficiency metric are set forth in the table below.

2019	2020	2021
$362,085	$622,370	$944,141

Additionally, the Settling Parties have identified several additional metrics to be tracked at this time, and for some of which the Company may become eligible for a financial performance incentive during the term of the MRP. These additional metrics are: (1) Distributed Energy Resources: Installed Energy Storage Capacity; (2) Distributed Energy Resources, CO_2: Electric Vehicles; (3) Distributed Energy Resources: Light Duty Government and Commercial Fleet Electrification; (4) PST Enablement: Awarded Low-income and Multi-unit EVSE Sites; and (5)

[21] In other words, for achievement at or above the minimum and up to the target level, the award will be calculated as the product of the maximum earnings level and the ratio of the achieved level to the maximum target.

PST Enablement: Distributed Generation (DG) Interconnection – Time to ISA.

a. *System Efficiency: Annual MW Capacity Savings*. The metric for this performance incentive mechanism will be the mega-watts (MW) of annual peak capacity savings. This metric is intended to reflect avoided capacity coincident with the ISO-NE peak hour. The proposed list of eligible resources for Annual MW Capacity Savings includes: (i) Demand Response, which will not be eligible for an incentive under the existing energy efficiency shareholder incentive; (ii) incremental net-metered behind-the-meter PV distributed generation in excess of Company forecast levels; (iii) incremental installed energy storage capacity; and (iv) any additional actions that the Company can identify to reduce peak demand, including non-wires alternatives expected to influence system peak that are not captured already under this or other metrics, and partnerships with third parties to provide peak reduction solutions. Achievement of the target is not based on any pre-determined mix of qualifying resources, but rather a total count of MW savings across all categories. The table below sets forth the targets and maximum earnings opportunity.

Annual MW Capacity Savings: Targets and Maximum Earnings Opportunity

	2019	2020	2021
Minimum	14	17	21
Target	17	21	24
Maximum	20	25	29
Earnings at Maximum ($000)	$362.09	$622.37	$944.14

For reporting performance on this metric, Narragansett Electric will submit resource-specific estimated MW savings. For existing eligible resources, Narragansett Electric will base savings on the following assumptions:

- For solar PV, Narragansett Electric will estimate the peak impact as the product of annual incremental installed capacity in excess of forecast levels available at the time of the ISO New England system peak, multiplied by a coincidence factor of 0.21. Narragansett Electric will report the forecast capacity and peak impacts of PV included in its annual peak forecast for the compliance year from the most recent annual forecast.[22]

- For residential Demand Response under the Company's Connected Solutions program, Narragansett Electric will report the number of participating customers multiplied by a deemed kW savings value per thermostat of 0.46 kW. Should the Company modify the structure of this program or otherwise expand residential demand response offerings, the calculation of savings will be appropriately modified. Any such modifications to the incentive calculation will be presented to the PUC for approval prior to the commencement of the relevant performance year.
- For commercial and industrial Demand Response, Narragansett Electric will report the average observed MW savings over called events.
- For any resources not listed above, Narragansett Electric will report the calculation of resource-specific savings and provide explanation of any underlying assumptions.

b. *Distributed Energy Resources*

i. <u>Installed Energy Storage Capacity</u>

This metric will be a scorecard metric as described in subsection f., below.

ii. <u>CO2: Consumer Electric Vehicles</u>

The metric is the incremental avoided tons of CO2 resulting from the Company's proposed Electric Transportation Initiative, as shown in the table below. The Company forecast was developed by applying a growth rate in EV sales for 2018 through 2021 derived from the

[22] For example, the Company's 2018 peak forecast projects incremental peak impacts from load-reducing solar PV in 2019 of 7.41 MW (35.3 MW of incremental capacity) in 2019.

Energy Information Administration's Annual Energy Outlook 2018 projection of EV sales in New England, to historic data on EV registrations in Rhode Island from R.L. Polk. The Company's forecast for incremental EVs adopted for years 2019 through 2021 is provided in the table below.

Narragansett Electric Forecast of Incremental EVs Registered in Rhode Island (Number of incremental vehicles)

	2019	2020	2021
Forecast incremental EVs	857	1,180	1,644

The Company will track and report performance by (1) calculating incremental vehicles above Company forecasts; (2) calculating the number of incremental BEVs and PHEVs by multiplying the total number of incremental vehicles by the share of all new registrations that were BEVs, and the share of all new registrations that were PHEVs; and (3) applying per vehicle annual CO2 emissions reduction values as follows:

- Incremental BEVs x 2.32 metric tons CO2
- Incremental PHEVs x 2.08 metric tons CO2

The PUC will evaluate whether to allow a financial performance incentive to be attached to the achievement of this metric prior to Rate Year 2.

iii. <u>Light Duty Government and Commercial Fleet Electrification</u>

This metric is intended to capture the impact of Narragansett Electric's electric transportation initiative on light-duty fleet adoption in Rhode Island relative to predicted market trends. The metric will measure incremental increase – above predicted levels – of government and commercial light-duty fleet electric vehicles in the state on an annual basis. The Company will track and report the incremental registrations (both in total and above the Company forecast included in Attachment 29) based on R.L. Polk data or an acceptable substitute should the Polk data become unavailable. The PUC will evaluate whether to allow a financial performance incentive to be attached to the achievement of this metric prior to Rate Year 2.

c. *PST Enablement*. This category of incentives will track Narragansett Electric's activities that support broad access to the benefits of power sector transformation activities, or otherwise provide foundational support for power sector transformation objectives. These incentives are reflective of the qualitative benefits of this support and enablement. Incentives are described in more detail below:

i. Activated Apartment Building and Disadvantaged Community EVSE Sites

This metric will track the Company's activation of EVSE sites for apartment buildings and disadvantaged communities. The Company will report the in-service date for make-ready work and charging stations installed in both site categories.

ii. Distributed Generation (DG) Interconnection – Time to ISA

This metric will be a scorecard metric, as described in subsection f., below.

d. *Calculating Incentive Value*. For the System Efficiency performance incentive, the value of the incentive is established using the following steps:

- the quantified net benefits of the relevant initiative were estimated using the Company's BCA assumptions and methodology; and
- 45% of the quantified net benefits were used to determine the utility incentive; the remaining 55% of net benefits will go to customers.

When the Company achieves one of the System Efficiency targets, it will receive an incentive based upon the dollar value associated with the relevant target. The magnitude of the utility incentive will be based upon the BCA results used at the time the Commission approves the Performance Incentive Mechanism. The utility incentive will not be modified based on after-the-fact reassessment of benefits and costs of the initiatives.

The Settling Parties agree that establishing a certain and meaningful incentive value is essential in order to most effectively drive Company performance in the delivery of the objectives supported by the incentive, and for these reasons, the Settling Parties agree that the System Efficiency Annual MW Capacity Savings performance incentive mechanism targets require a presumption of cost-effectiveness to establish the incentive size based on the BCA results, as more fully described below. For this initiative, the Company will be allowed to earn the incentive regardless of whether it turns out to be cost-effective. The Settling Parties agree and acknowledge that the Company's demand response initiatives are expected to play an important role in achievement of the System Efficiency Annual MW Capacity Savings targets. It is not clear that these programs will be demonstrated as cost-effective based on quantifiable benefits in their initial years; however, given their expected value to the system as they are further developed and expanded, their importance to enabling investment in and development of load management solutions, and the potential savings to participating customers, they are assumed to be cost-effective (via the assumed ratio of costs to benefits for the incentive) for the purpose of setting the value of the Annual MW Capacity Savings incentive.

e. *Reporting Performance*. Narragansett Electric will file an annual performance incentive mechanism report with the PUC no later than March 1 annually (1) comparing the Company's performance relative to each performance incentive mechanism target; (2) describing the savings achieved, (3) calculating incentives earned, including proration of any incentives related to metric achievement between the minimum, midpoint, and the maximum target levels, (4) any targets not achieved, and (5) demonstrating the cost and benefit impacts of the metric on the energy system, customers, and society using the Docket No. 4600 Benefit-Cost Framework. Narragansett Electric will file a mid-year update on or before September 1 annually that describes the Company's progress toward each Performance Incentive Mechanism metric target and the actions taken by the Company to achieve target performance. The mid-year update also will include an assessment of whether (and, for the Annual MW Capacity Savings performance incentive mechanism, through which measures) the Company expects to meet its annual performance incentive mechanism targets.

f. *Scorecard Metrics*. The Company is proposing to track and report the following scorecard metrics:

i. DG Interconnections

Narragansett Electric will track the number of business days from executed ISA to distribution system modifications by category of interconnection (*i.e.*, simple, expedited, standard). For each category, the Company will calculate and report the averages and the variances from the averages.

ii. DG-Friendly Substation Transformers

Narragansett Electric will base reporting on the number of incremental 3VO installations completed.

iii. Utilization of EVSE in Low-income Areas

Narragansett Electric will report utilization rates at all EVSE sites installed through the Charging Station Demonstration Program. The reports will identify which EVSE sites are in low income areas.

iv. Reduction of Uncollectable Debt

Narragansett Electric will report enrollment in the Arrearage Management Plan (AMP) at the point of potential termination from service for purposes of developing a baseline and eventually setting an improvement target from this baseline, to maintain service to the low-income customer and prevent expansion of uncollectible debt.

v. Increased Stability of Service through Increased Enrollment in the Low Income Discount

Narragansett Electric will report enrollment in the low-income discount, represented by number of customers receiving delivery service on Rate A-60, for the purposes of developing a baseline and eventually setting an enrollment target that improves upon the baseline. Such a target would incentivize expanded enrollment on Rate A-60 thus increasing stability of service and reducing the frequency of the termination/reconnection cycle. This provision shall not be construed to allow customers to remain on Rate A-60 if they no longer are eligible for Rate A-60.

vi. NPP Residential Customer Demand Response Participation

Narragansett Electric will work with NPPs to measure the number of NPP residential customers participating in Narragansett Electric's Connected Solution program or any future demand response program that works with WiFi-enabled or smart thermostat(s) and other connected smart devices to reduce electricity use during periods of high energy demand.

vii. Distributed Energy Resources - Installed Energy Storage Capacity

Narragansett Electric will track incremental installed energy storage capacity. It is the intention of the Settling Parties that Narragansett Electric will coordinate deployment of energy storage with its distribution system planning and heat map activities, and that storage activities undertaken by Narragansett Electric should provide opportunities for market engagement by NPPs and other third-parties.

viii. PST Enablement - Distributed Generation (DG) Interconnection – Time to ISA

Narragansett Electric will track its performance for the simplified, expedited without supplemental review, and standard tracks in meeting or outperforming tariff timelines for providing an executable interconnection service agreement. Narragansett Electric's performance will be measured by:

- aggregating the average time measured in Business Days necessary to issue an executable Interconnection Service Agreement commencing from the date an application is received, for each track identified above (Aggregate Necessary Tariff Time Frames), and comparing such performance to
- the total aggregate number of Business Days allowed by its Interconnection Tariff to issue an executable Interconnection Service Agreement commencing from the date an application is received (Aggregate Allowed Tariff Time Frames).

g. *Recovery of Earned Incentives*. The Company shall recover any approved performance incentives earned for achieving the performance incentive mechanism targets listed above through the operation of a new reconciling mechanism pursuant to the Performance Incentive Recovery Provision. The Company will make an annual filing with the PUC to request recovery of performance incentives earned pursuant to the Performance Incentive Mechanisms authorized by the PUC and approval of a separate Performance Incentive Factor filing based upon the requested earned incentives.

20. Deferral of Certain "Special Sector" Program Costs and Revenues

a. In recognition of the uncertainty of timing and control of certain Special Sector Programs identified below, a deferral mechanism shall be implemented in accordance with this section.

b. The Special Sector Programs to which this section shall apply includes:

i. The Electric Transportation program, described in Section 17.a. of this Agreement; and

ii. The Energy Storage Demonstration program, described in Section 17.d. (collectively referred to as the Special Sector Programs).

c. The costs and annual base distribution rate allowances allocated to each of the Special Sector Programs shall be separately monitored and reconciled at the end of each Rate Year.

d. To the extent the base distribution rate allowances allocated to the program exceed the actual costs incurred, the Company shall record the difference to a regulatory liability account. To the extent the deferral was caused by a reasonable delay in implementation, the deferral shall be applied to program cost incurrence when the program costs are later incurred. To the extent the deferral was caused by a cost reduction or funds not spent for reasons other than a reasonable delay, the deferral shall be held for the benefit of customers and the PUC shall determine how it shall be applied against other programs or costs that otherwise might have been borne by customers. The amount of any such deferral shall incur carrying charges at the WACC for Narragansett Electric for capital expenses and the customer deposit rate for Narragansett Electric for O&M costs.

e. To the extent the actual costs of a program exceed the base distribution rate allowances that were allocated to the program, the overspending shall be borne by the Company, unless the PUC allows the Company to record the difference to a regulatory asset for recovery at a later date. The PUC shall be under no obligation to approve a regulatory asset; however, a regulatory asset shall only be approved if the Company demonstrates that the costs were prudently incurred consistent with the program objectives and the overspending was out of its reasonable control.

21. <u>Next Rate Case Filing</u>

The Company's next general rate case shall be a combined electric and gas rate case unless the Company and the Division mutually agree that they should be filed separately. When the Company's next rate case is filed, the Company shall file complete revenue requirements for the rate year and no fewer than two additional consecutive twelve-month rate-year periods, to facilitate the PUC's and Division's review and potential approval of a multi-year rate plan.

a. The Company shall submit its next rate case filing to the PUC so that new base distribution rates take effect no later than September 1, 2022. Nothing in this Settlement Agreement shall preclude the Company from filing its next general rate case at any time earlier during the term of this Rate Plan or any extension thereof.

b. If the Division provides its consent to an extension of the term of this Rate Plan, the Division may specify another date upon which new base distribution rates are to become effective beyond September 1, 2022 in its place, but is not required to do so.

i. To the extent new base distribution rates resulting from the filing of the Company's next general rate case are not in effect by September 1, 2022, the Settlement

Agreement shall remain in effect during the interim and if required, the Performance Incentive Mechanism provision shall be extended to cover the additional interim period.

22. <u>Additional Provisions</u>

a. *Excess Deferred Taxes True Up*. As discussed in the Company's response to PUC 4-1 (Supplemental), a copy of which is provided as Attachment 24 hereto, to account for revisions to the corporate tax rate modified by the federal Tax Cuts and Jobs Act (Tax Act), the Company has recorded the $116 million and $51 million estimates of customer-related excess deferred federal income tax for Narragansett Electric and Narragansett Gas, respectively, to a tax regulatory liability account in recognition that customers will be refunded those excess deferred taxes. The Company will be able to calculate more accurately excess deferred taxes and the timing over which they should be returned when its fiscal year ended March 31, 2018 audited financial statements are completed during the late summer 2018. These estimates will become final with the filing of the fiscal year ended March 31, 2018 federal income tax return in December 2018, and the excess deferred tax regulatory liability will be adjusted to reflect that final balance.

This Settlement Agreement provides for a reduction to Narragansett Electric and Narragansett Gas revenue requirements by a high level estimate of excess deferred income tax amortization of $5.1 million and $2.0 million, respectively. The Company will true up these estimates in a supplemental compliance filing to be filed with the PUC in Docket No. 4770 after the Company files its Fiscal Year 2018 federal income tax return in December 2018. The true-up will reconcile the impact of the actual excess deferred tax amortization with the estimated amounts identified above, and will determine the final revenue requirements for Narragansett Electric and Narragansett Gas effective September 1, 2018. From these supplemental revenue requirements, the Company will calculate the difference between the revenue requirements it began recovering September 1, 2018 and the revenue requirements in the supplemental compliance filing in Docket No. 4770 (Deferred Tax Differential). The Company will submit to the PUC for its review and approval a filing to address the ratemaking treatment of the Deferred Tax Differential for Narragansett Electric and Narragansett Gas no later than March 1, 2019. The filing shall propose the following:

Narragansett Electric: The Company will provide the calculation of the Narragansett Electric Deferred Tax Differential and the revised Annual Target Revenue (ATR) of its Revenue Decoupling Mechanism (RDM), reflecting an adjustment for the Deferred Tax Differential. In addition, Narragansett Electric will evaluate the appropriateness of proposing revised base distribution rates based upon the amount of the true-up to the revenue requirement to reflect the effect of the Deferred Tax Differential if the difference is determined to be of an amount that adjusting base distribution rates would be appropriate. The Company will present its evaluation on the necessity of revising base distribution rates as part of its proposal regarding the ratemaking treatment of the Deferred Tax Differential.

Narragansett Gas: The Company will provide the calculation of the Narragansett Gas Deferred Tax Differential. In addition, Narragansett Gas will evaluate the appropriateness of (i) proposing revised base distribution rates based upon the amount of the true-up to the revenue requirement to reflect the effect of the Deferred Tax Differential as described below, or (ii) proposing that the Deferred Tax Differential be credited through the DAC if the difference is determined to be relatively small such that adjusting base distribution rates would not be needed. The Company will present its evaluation on the necessity of revising base distribution rates as part of its proposal regarding the ratemaking treatment of the Deferred Tax Differential. If

Narragansett Gas proposes to change base distribution rates, the filing shall include the following: (1) for all customers, new base distribution rates effective on a prospective basis on a date determined with respect to the timing of the supplemental compliance filing; (2) for customers included in Narragansett Gas's RDM,[23] revised target revenue-per-customer amounts based upon the supplemental revenue requirements; and (3) for customers excluded from Narragansett Gas's RDM,[24] the difference for this group of customers be credited to, or recovered from, these customers through a one-time adjustment included in the DAC filing submitted to the PUC by August 1, 2019. If Narragansett Gas revises its target revenue-per-customer amounts, the revised revenue-per-customer amounts shall be reflected in its subsequent RDM reconciliation filings submitted to the PUC annually by July 1 until the effective date of base distribution rates resulting from a future general rate case. Any revised target revenue-per-customer amounts shall be subject to Section 22.c. of this Settlement Agreement.

For this high level estimate, this Settlement Agreement provides for the amortization of all property related excess deferred taxes over an approximate 30 year average service life of its assets. The composite depreciation rate currently in effect is 3.40 percent and 3.38 percent for Narragansett Electric distribution plant and Narragansett Gas plant, respectively, both of which equate to average service lives of just under 30 years. The Company agrees to amortize its non-property related excess deferred taxes over a period of ten years, as was proposed by the Division, until the true-up is performed.

b. *Minimum Funding Obligation*. For the purpose of determining its "Minimum Funding Obligation" and the carrying costs that apply to that obligation, the

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[23] Pursuant to Narragansett Gas's tariff, customers included in the RDM are those receiving service on Narragansett Gas's residential, small C&I, and medium C&I rate schedules.
[24] Pursuant to Narragansett Gas's tariff, customers excluded from the RDM are those receiving service on Narragansett Gas's large C&I, extra-large C&I, and non-firm rate schedules.

Company shall be permitted to combine the funding of pensions and post-employment benefits other than pensions (PBOPs), thereby offsetting, for example, any deficiencies in PBOPs funding with any excess pension funding. The Company will be required to accrue and defer carrying charges on only the net unfunded pension/PBOP amount. The Minimum Funding Obligation is the Company's obligation to contribute amounts recovered from customers to the pension and PBOP plans as it is being recovered. The Minimum Funding Obligation level is equal to the amount billed to customers plus the amounts of capitalized pension and PBOP costs. The amount billed to customers includes (1) the pension and PBOP allowance in base distribution rates, and (2) plus or minus the amount billed or credited to customers through the PAF. If the Company does not fund its pension and PBOP plans at the Minimum Funding Obligation level, the Company will pay a carrying charge to customers at the weighted average cost of capital. This payment will be applied to the cumulative five-quarter average shortfall between the Minimum Funding Obligation level and amounts the Company contributes to the pension and PBOP plans, plus amounts paid to the Service Company for allocated pension and PBOP costs. The ability to combine the funding of pension and PBOPs will give the Company the flexibility to avoid permanently overfunding the PBOP plan, while at the same time, giving the Company the ability to meet its Minimum Funding Obligation.

c. *Narragansett Gas Forecast of Plant Additions for Gas Growth*. To ensure that customers will be credited with an accurate level of gas growth revenue and to address the Division's concern regarding the Company's growth capital forecast, this Settlement Agreement provides that Narragansett Gas will calculate the difference between the forecast gas-growth capital revenue requirement and the actual gas growth capital revenue requirement in Rate Year 1. Attachment 25 provides an illustrative calculation to be employed at the end of Rate

Year 1. As shown on this attachment, this difference shall be added to or subtracted from the total Revenue Decoupling Mechanism (RDM) class revenue requirement used to establish base distribution rates in these proceedings. This adjusted total RDM class revenue requirement will be divided by the actual average customer totals per rate class during Rate Year 1 to arrive at the class revenue per customer amount to be used in the calculation of RDM adjustments for all periods commencing September 1, 2018, and until new base distribution rates are established for gas service. The method illustrated in Attachment 25 does not establish any precedent for the calculation of RDM adjustments subsequent to future gas base distribution rate cases.

d. *Charitable Contributions*. Intentionally Deleted.

e. *American Gas Association (AGA) and Edison Electric Institute (EEI) Annual Membership Dues*. To settle concerns raised by NERI associated with lobbying costs, which are not included in the Company's revenue requirements for Narragansett Gas and Narragansett Electric, charged to the Company by AGA and EEI, respectively, the Company has agreed to send letters to AGA and EEI requesting information regarding how such trade associations allocate costs between lobbying and non-lobbying expenses and substantiation of the allocation. The Company will provide the responses to the Division and the PUC.

f. *Low Income Reporting*. The Company, the Division, and GWC shall work together with PUC Staff to develop reporting requirements for existing and new electric and natural gas low-income rates, programs, and discounts. These reporting requirements shall be designed to: (1) inform the PUC how the low-income rates, programs, and discounts advance the rate design principles set forth in the Docket 4600 Guidance Document, and (2) provide information needed to support future investigation into a more dynamic low-income-rate design.

23. Other Provisions

a. The Settling Parties agree to request that the PUC adopt the terms of this Settlement Agreement without modification. The Settling Parties intend that this Settlement Agreement will be adopted by the PUC as being in the public interest and agree individually to advocate its adoption by the PUC in its entirety and to act so as to expedite that result.

b. The Settling Parties intend this Settlement Agreement to be a complete resolution of all issues in Docket No. 4770 and Docket No. 4780. It is understood that each provision of this Settlement Agreement is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the PUC. Except as expressly set forth herein, none of the Settling Parties is deemed to have approved, agreed to, or consented to any principle, methodology, or interpretation of law underlying or supposed to underlie any provision herein, including without limitation with respect to the PUC's August 3, 2018 open meeting decisions (and rationale therefor) regarding charitable contributions, carrying charges, and R.I. Gen. Laws § 39-2-1.2.

c. Except as otherwise stated in this Settlement Agreement, the provisions of the Settlement Agreement apply solely to, and are binding only in the context of, this Settlement Agreement and these proceedings. It is not the intention of this Settlement Agreement that it establishes any binding precedent. None of the positions taken by any Settling Party with respect to this Settlement Agreement nor the fact that a Settling Party is a signatory to this Settlement Agreement, may be referred to, cited by, or relied upon by anyone in any manner as precedent or otherwise in any other proceeding before the PUC or any other regulatory body or before any court of law as proof of assent or agreement by such Settling Party to the approval of any particular regulatory policy or principle that may be interpreted to arise out of this Settlement

Agreement. Concessions made by any Settling Party on any issue do not preclude that party from addressing such issues in future rate proceedings or in other proceedings. Any failure by any Settling Party to abide by the terms of this subsection shall not give rise to any claim against such Settling Party for breach of this Settlement Agreement, unless: (i) the Settling Party is provided notice of such failure and an opportunity to cure such failure; and (ii) such Settling Party does not cure such failure within seven (7) business days after such notice.

d. The Settling Parties recognize that certain provisions of this Settlement Agreement contemplate actions to be taken in the future and agree to cooperate with each other in good faith in taking such actions.

In the event of any disagreement over the interpretation of this Settlement Agreement that cannot be resolved informally among the Settling Parties, the party claiming a dispute will serve a Notice of Dispute on the remaining parties, briefly identifying the provision or provisions of this Settlement Agreement under dispute and the nature of the dispute, and convening a conference in a good faith attempt to resolve the dispute. If any such efforts are not successful in resolving the dispute among the Settling Parties, the matter will be submitted to the PUC for resolution.

e. Except as set forth herein, following the expiration of the term of the Rate Plan, all provisions of this Settlement Agreement will continue until changed by order of the PUC. Except as expressly provided otherwise, any targets, goals, deferral thresholds, or other similar items set forth in this Settlement Agreement for Rate Year 3 will continue beyond Rate Year 3 until modified by the PUC.

f. Nothing in this Settlement Agreement will be construed as precluding the active parties from convening additional conferences and from reaching agreement to extend this

Settlement Agreement on mutually-acceptable terms and from presenting an agreement concerning such extension to the PUC for its approval.

g. The Settling Parties recognize that the PUC has an ongoing obligation to modify rates to protect the public against improper and unreasonable rates that cannot be precluded by a settlement agreement

h. This Settlement Agreement sets forth the entire agreement of the Settling Parties and supersedes any prior or contemporaneous written documents or oral understandings among the Settling Parties concerning the matters addressed herein. In the event of any conflict between this Settlement Agreement and any other document addressing the same subject matter, this Settlement Agreement will control. Notwithstanding the foregoing, nothing in this Settlement Agreement is intended to modify the terms of the Docket No. 4686 Settlement Agreement.

i. Notices and other communications required to be provided or made under the Settlement Agreement shall be in writing and shall be deemed to have been given:

i. When delivered by hand (with written confirmation of receipt);

ii. When received by the addressee if sent by a nationally recognized overnight courier or by certified or registered mail, return receipt requested, postage prepaid; or

iii. On the date sent by e-mail if sent before 5:00 p.m., recipient's time, and on the next day that is not a Saturday, Sunday, or Federal Holiday, if sent thereafter; in each case, to the applicable address and/or email address set forth on Attachment 27; provided that, if any notice is tendered to an addressee and the delivery thereof is refused by such addressee, such notice shall be effective upon such tender.

Any party hereto may change its address and/or email address reflected in Attachment 27 upon 15 days' prior notice of such change to the other parties hereto.

ARTICLE III: SETTLEMENT CONDITIONS

A. This Settlement Agreement is the result of negotiations among the Settling Parties. The discussions that have produced this Settlement Agreement have been conducted on the explicit understanding that all offers of settlement and discussions relating hereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussion, and are not to be used in any manner in connection with these or other proceedings involving any one or more of the parties to this Settlement Agreement or otherwise. The agreement by a party to the terms of this Settlement Agreement shall not be construed as an agreement as to any matter of fact or law for any other purpose.

B. Unless expressly stated herein, the making of this Settlement Agreement establishes no principles and shall not be deemed to foreclose any Settling Party from making any contention in any other proceeding or investigation.

C. The Settling Parties submit this Settlement Agreement on the condition that it be approved in full by the PUC and on the further condition that, if the PUC (i) rejects this Settlement Agreement; (ii) fails to accept this Settlement Agreement as filed; or (iii) accepts this Settlement Agreement subject to conditions unacceptable to any Settling Party hereto, then this Settlement Agreement shall be deemed withdrawn, shall not constitute part of the record in any proceeding or be used for any purpose, and shall be deemed null and void, and the Settling Parties will be free to pursue their respective positions in these proceedings without prejudice.

D. The Settling Parties recognize that the PUC has an ongoing obligation to modify rates to protect the public against improper and unreasonable rates, and that obligation cannot be precluded by a settlement agreement.

E. This Settlement Agreement may be signed in counterparts, each of which shall be deemed an original and all of which together shall constitute one in the same document, and will be binding on each Settling Party when the counterparts have been executed.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF, the parties agree that this Settlement Agreement is reasonable and have caused this document to be executed by their respective representatives, each being fully authorized to do so, as of this 16th day of August, 2018.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:____________________
Its: PRESIDENT
Dated: 8/15/18

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:____________________
Its:
Dated:________________

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:____________________
Its:
Dated:________________

CONSERVATION LAW FOUNDATION

By:____________________
Its:
Dated:________________

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:____________________
Its:
Dated:________________

THE GEORGE WILEY CENTER

By:____________________
Its:
Dated:________________

NORTHEAST CLEAN ENERGY COUNCIL

By:____________________
Its:
Dated:________________

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:____________________
Their:
Dated:________________

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:______________________________
Its:
Dated:__________________

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By: [signature]
Its: Counsel
Dated: August 16, 2018

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:______________________________
Its:
Dated:__________________

CONSERVATION LAW FOUNDATION

By:______________________________
Its:
Dated:__________________

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:______________________________
Its:
Dated:__________________

THE GEORGE WILEY CENTER

By:______________________________
Its:
Dated:__________________

NORTHEAST CLEAN ENERGY COUNCIL

By:______________________________
Its:
Dated:__________________

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:______________________________
Their:
Dated:__________________

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:______________________________
Its:
Dated:__________________

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:______________________________
Its:
Dated:__________________

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:______________________________
Its: Attorney
Dated: 8/14/2018

CONSERVATION LAW FOUNDATION

By:______________________________
Its:
Dated:__________________

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:______________________________
Its:
Dated:__________________

THE GEORGE WILEY CENTER

By:______________________________
Its:
Dated:__________________

NORTHEAST CLEAN ENERGY COUNCIL

By:______________________________
Its:
Dated:__________________

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:______________________________
Their:
Dated:__________________

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:____________________
Its:
Dated:________________

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:____________________
Its:
Dated:________________

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:____________________
Its:
Dated:________________

CONSERVATION LAW FOUNDATION

By: Jerry Elmer
Its: SENIOR ATTORNEY
Dated: 8/14/18

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:____________________
Its:
Dated:________________

THE GEORGE WILEY CENTER

By:____________________
Its:
Dated:________________

NORTHEAST CLEAN ENERGY COUNCIL

By:____________________
Its:
Dated:________________

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:____________________
Their:
Dated:________________

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THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:____________________
Its:
Dated:____________

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:____________________
Its:
Dated:____________

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:____________________
Its:
Dated:____________

CONSERVATION LAW FOUNDATION

By:____________________
Its:
Dated:____________

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By: Kelsey A. Hen
Its: Attorney
Dated: 15 Aug 2018

THE GEORGE WILEY CENTER

By:____________________
Its:
Dated:____________

NORTHEAST CLEAN ENERGY COUNCIL

By:____________________
Its:
Dated:____________

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:____________________
Their:
Dated:____________

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID

By:________________________________
Its:
Dated:____________________

RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

By:________________________________
Its:
Dated:____________________

RHODE ISLAND OFFICE OF ENERGY RESOURCES

By:________________________________
Its:
Dated:____________________

CONSERVATION LAW FOUNDATION

By:________________________________
Its:
Dated:____________________

DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES

By:________________________________
Its:
Dated:____________________

THE GEORGE WILEY CENTER

By:__________________
Its: Attorney
Dated:__8/15/18__________

NORTHEAST CLEAN ENERGY COUNCIL

By:________________________________
Its:
Dated:____________________

WAL-MART STORES, LP AND SAM'S EAST, INC.

By:________________________________
Their:
Dated:____________________

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Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID	RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS
By:______________________ Its: Dated:______________	By:______________________ Its: Dated:______________
RHODE ISLAND OFFICE OF ENERGY RESOURCES	CONSERVATION LAW FOUNDATION
By:______________________ Its: Dated:______________	By:______________________ Its: Dated:______________
DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES	THE GEORGE WILEY CENTER
By:______________________ Its: Dated:______________	By:______________________ Its: Dated:______________
NORTHEAST CLEAN ENERGY COUNCIL	WAL-MART STORES, LP AND SAM'S EAST, INC.
By:______________________ Its: ATTORNEY Dated: 8/15/18	By:______________________ Their: Dated:______________

IN WITNESS WHEREOF, the parties agree that this Settlement Agreement is reasonable and have caused this document to be executed by their respective representatives, each being fully authorized to do so, as of this 16th day of August, 2018.

Respectfully submitted,

THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID	RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS
By:________________	By:________________
Its:	Its:
Dated:__________	Dated:__________
RHODE ISLAND OFFICE OF ENERGY RESOURCES	CONSERVATION LAW FOUNDATION
By:________________	By:________________
Its:	Its:
Dated:__________	Dated:__________
DEPARTMENT OF THE NAVY AND THE FEDERAL EXECUTIVE AGENCIES	THE GEORGE WILEY CENTER
By:________________	By:________________
Its:	Its:
Dated:__________	Dated:__________
NORTHEAST CLEAN ENERGY COUNCIL	WAL-MART STORES, LP AND SAM'S EAST, INC.
By:________________	By: Melissa Horne
Its:	Their: Attorney
Dated:__________	Dated: 8/15/18

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By: James Rhodes
Its: Attorney
Dated: 8/15/2018

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By: James Rhodes
Their: Attorney
Dated: 8/15/2018

CHARGEPOINT, INC.

By:____________________
Its:
Dated:____________________

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:____________________
Their:
Dated:____________________

NEW ENERGY RHODE ISLAND

By:____________________
Its:
Dated:____________________

NATIONAL RAILROAD PASSENGER CORPORATION

By:____________________
Its:
Dated:____________________

ACADIA CENTER

By:____________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:________________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:________________________________
Their:
Dated:____________________

CHARGEPOINT, INC.

By: Edward D. Pare, Jr. JDR
Its: Attorney
Dated: August 15, 2018

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:________________________________
Their:
Dated:____________________

NEW ENERGY RHODE ISLAND

By:________________________________
Its:
Dated:____________________

NATIONAL RAILROAD PASSENGER CORPORATION

By:________________________________
Its:
Dated:____________________

ACADIA CENTER

By:________________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:______________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:______________________________
Their:
Dated:____________________

CHARGEPOINT, INC.

By:______________________________
Its:
Dated:____________________

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By: Craig Waksler /
Their: Counsel
Dated: 8/15/18

NEW ENERGY RHODE ISLAND

By:______________________________
Its:
Dated:____________________

NATIONAL RAILROAD PASSENGER CORPORATION

By:______________________________
Its:
Dated:____________________

ACADIA CENTER

By:______________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:________________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:________________________________
Their:
Dated:____________________

CHARGEPOINT, INC.

By:________________________________
Its:
Dated:____________________

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:________________________________
Their:
Dated:____________________

NEW ENERGY RHODE ISLAND

By:________________________________
Its: Counsel
Dated: August 15, 2018

NATIONAL RAILROAD PASSENGER CORPORATION

By:________________________________
Its:
Dated:____________________

ACADIA CENTER

By:________________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:______________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:______________________________
Their:
Dated:____________________

CHARGEPOINT, INC.

By:______________________________
Its:
Dated:____________________

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:______________________________
Their:
Dated:____________________

NEW ENERGY RHODE ISLAND

By:______________________________
Its:
Dated:____________________

NATIONAL RAILROAD PASSENGER CORPORATION

By: [signature]
Its: Attorney
Dated: 18 August 2018

ACADIA CENTER

By:______________________________
Its:
Dated:____________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT

By:______________________________
Its:
Dated:__________________

ENERGY CONSUMERS ALLIANCE OF NEW ENGLAND , INC. D/B/A PEOPLE'S POWER AND LIGHT; SIERRA CLUB; AND NATURAL RESOURCES DEFENSE COUNCIL, jointly

By:______________________________
Their:
Dated:__________________

CHARGEPOINT, INC.

By:______________________________
Its:
Dated:__________________

DIRECT ENERGY BUSINESS, LLC; DIRECT ENERGY SERVICES, LLC; AND DIRECT ENERGY SOLAR

By:______________________________
Their:
Dated:__________________

NEW ENERGY RHODE ISLAND

By:______________________________
Its:
Dated:__________________

NATIONAL RAILROAD PASSENGER CORPORATION

By:______________________________
Its:
Dated:__________________

ACADIA CENTER

By: [signature]
Its: Attorney
Dated: Aug 15, 2018

SCHEDULE A

List of Attachments

Compliance Attachment No.	Compliance Attachment Name	Book No.
1	Narragansett Electric and Narragansett Gas Revenue Requirement Settlement Terms (Rate Years 1, 2, 3)	1
2	Narragansett Electric and Narragansett Gas Revenue Requirements (Rate Years 1, 2, 3)	1, 2
3	Narragansett Electric and Narragansett Gas Supporting Workpapers, including Cash Working Capital Studies	2, 3, 4
4	Narragansett Electric and Narragansett Gas Grid Modernization Revenue Requirements (Rate Years 1, 2, 3)	5
5	Narragansett Electric Special Sector Programs Revenue Requirements (Rate Years 1, 2, 3)	5
6	Narragansett Electric Allocated Cost of Service Study (Rate Year 1)	5
7	Narragansett Electric Allocator Study	5
8	Narragansett Electric Revenue Allocation (Rate Years 1, 2, 3) (including allocation of results of Rate Year 1 Allocated Cost of Service Study, plus (2) Years 2 and 3 increases, plus (3) PST revenue requirements for Rate Years 1, 2, 3))	5
9	Narragansett Electric Distribution Rate Design (Rate Years 1, 2, 3)	5
10	Narragansett Electric Bill Impacts (November 1, 2017 vs. Rate Year 1, Rate Year 1 vs. Rate Year 2, Rate Year 2 vs. Rate Year 3)	5
11	Narragansett Electric Streetlight Replacement Cost Study	6
12	Narragansett Electric Development of Rates Associated With Various Recovery Mechanisms	6
13	Narragansett Electric Redlined Tariffs (Marked to Show Changes from Those Currently in Effect)	6
14	Narragansett Gas Allocated Cost of Service Study (Rate Year 1)	6
15	Narragansett Gas Allocator Study	7
16	Narragansett Gas Revenue Allocation, Firm and Non-Firm Distribution Rate Design, and Revenue-per-Customer Targets by Rate Class (Rate Years 1, 2, 3; would include (1) allocation of results of Rate Year 1 Allocated Cost of Service Study, plus (2) Years 2 and 3 increases, plus (3) gas-related PST revenue requirements for Rate Years 1, 2, 3))	7
17	Narragansett Gas Bill Impacts (November 1, 2017 vs. Rate Year 1, Rate Year 1 vs. Rate Year 2, Rate Year 2 vs. Rate Year 3)	7
18	Narragansett Gas Development of Rates Associated With the Distribution Adjustment Clause and Gas Cost Recovery Clause	7

SCHEDULE A

List of Attachments

Compliance Attachment No.	Compliance Attachment Name	Book No.
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The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line	Description	Settlement: Rate Year Ending August 31, 2019 (a)	Settlement: Base Revenue Increase Required (b)	Settlement: Rate Year Ending August 31, 2019 with Base Revenue Requirement (c)=(a)+(b)	Compliance: Rate Year Ending August 31, 2019 (d)	Compliance: Base Revenue Increase Required (e)	Compliance: Rate Year Ending August 31, 2019 with Base Revenue Requirement (f)=(d)+(e)	Delta: Rate Year Ending August 31, 2019 (g)=(d)-(a)	Delta: Base Revenue Increase Required (h)=(e)-(b)	Delta: Rate Year Ending August 31, 2019 with Base Revenue Requirement (i)=(f)-(c)
1	Revenues	$279,192,430	$14,081,470	$293,273,900	$279,091,943	$12,038,936	$291,130,879	($100,487)	($2,042,534)	($2,143,021)
2										
3	Purchased Power & Other Reconciling Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0
4										
5	Net Distribution Revenues	$279,192,430	$14,081,470	$293,273,900	$279,091,943	$12,038,936	$291,130,879	($100,487)	($2,042,534)	($2,143,021)
6										
7	Operation & Maintenance Expenses	$152,904,072	$183,467	$153,087,538	$150,603,298	$156,855	$150,760,152	($2,300,774)	($26,612)	($2,327,386)
8										
9	Amortization of Regulatory Deferrals	$332,482	$0	$332,482	$471,908	$0	$471,908	$139,426	$0	$139,426
10										
11	Amortization of Utility Plant	$0	$0	$0	$0	$0	$0	$0	$0	$0
12										
13	Depreciation	$50,128,332	$0	$50,128,332	$50,128,332	$0	$50,128,332	$0	$0	$0
14										
15	Municipal Taxes	$30,530,258	$0	$30,530,258	$30,530,258	$0	$30,530,258	$0	$0	$0
16										
17	Payroll Taxes	$4,198,324	$0	$4,198,324	$4,154,522	$0	$4,154,522			
18										
19	Gross Receipts Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0
20										
21	Other Taxes	$454,406	$0	$454,406	$454,406	$0	$454,406	$0	$0	$0
22										
23	Interest on Customer Deposits	$132,127	$0	$132,127	$132,127	$0	$132,127	$0	$0	$0
24										
25	Total Operating Revenue Deductions	$238,680,001	$183,467	$238,863,467	$236,474,851	$156,855	$236,631,706	($2,205,150)	($26,612)	($2,231,761)
26										
27	Operating Income Before Income Taxes	$40,512,429	$13,898,004	$54,410,433	$42,617,092	$11,882,081	$54,499,173	$2,104,663	($2,015,923)	$88,740
28										
29	Income Taxes	$687,356	$2,918,581	$3,605,936	$1,157,091	$2,495,237	$3,652,328	$469,735	($423,344)	$46,392
30										
31	Operating Income After Income Taxes	$39,825,074	$10,979,423	$50,804,497	$41,460,001	$9,386,844	$50,846,845	$1,634,927	($1,592,579)	$42,348
32										
33	Rate Base	$728,902,391		$728,902,391	$729,509,971		$729,509,971	$607,580		$607,580
34										
35	Rate of Return	5.46%	Line 31(a) / Line 33(a)		5.68%	Line 31(d) / Line 33(d)				
36										
37										

Line	Description	Settlement (a)	Settlement reference	Compliance (d)	Compliance reference	Delta (g)
38	Revenue Deficiency					
39	Earned Rate of Return	5.46%	Line 35(a)	5.68%	Line 35(d)	0.22%
40	Rate Year Required Rate of Return	6.97%	Attachment 2, Schedule 1 ELEC, Page 4, Line 9(c)	6.97%	Compliance Attachment 2, Schedule 1-ELEC, Page 4, Line	0.00%
41	Rate of Return Deficiency	1.51%	Line 40(a) - Line 39(a)	1.29%	Line 40(d) - Line 39(d)	-0.22%
42	Rate Base	$728,902,391	Line 33(a)	$729,509,971	Line 33(d)	$607,580
43	Net Operating Income Deficiency	$10,979,423		$9,386,844		($1,592,579)
44	Gross Revenue Conversion Factor	1.282533	Line 53(a)	1.282533	Line 53(d)	1.282533
45	**Revenue Deficiency**	$14,081,470	Line 43(a) * Line 44(a)	$12,038,936	Line 43(d) * Line 44(d)	($2,042,534)
46						
47	Gross Revenue Conversion Factor					
48	Gross Revenue	1.000000		1.000000		
49	Uncollectible expense	(0.013029)	Attachment 2, Schedule 22, Page 6, Line 15	(0.013029)	Compliance Attachment 2, Schedule 22, Page 6, Line 15	
50	Revenue net of Uncollectibles	0.986971		0.986971		
51	Composite income tax rate	(0.207260)	Line 50(a) x (- 0.21%)	(0.207260)	Line 50(d) x (- 21%)	
52	Net income effect of 1.000 Revenue	0.779707	Line 50(a) + Line 51(a)	0.779707	Line 50(d) + Line 51(d)	
53	Gross Revenue Conversion Factor	1.282533	1 / Line 52(a)	1.282533	1 / Line 52(d)	

Line Notes:
Line 1 - decrease in rate year ISR revenues due to tax reform (lower tax rate, elimination of bonus depreciation and lower pre-tax return on rate base)
Line 9 - increase in projected rate case expenses (Record request 39)
Line 7 - refer to Pages 2 and 3
Line 33 - refer to explanations at Page 4

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary - ELECTRIC

			Settlement			Compliance			Delta		
			Rate Year Ending August 31, 2019	Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2019	Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2019	Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2021
	Operation & Maintenance Expenses:	Schedule Reference	(a)	(b)	(c)	(d)	(e)	(f)	(g)=(d)-(a)	(h)=(e)-(b)	(i)=(f)-(c)
1	Labor	Schedule 12	$51,707,477	$53,560,974	$55,183,457	$50,809,286	$52,633,681	$54,227,114	($898,191)	($927,293)	($956,343)
2	Health Care	Schedule 13	$6,458,547	$6,689,763	$6,892,463	$6,391,424	$6,620,876	$6,821,489	($67,123)	($68,887)	($70,974)
3	Group Life Insurance	Schedule 14	$567,542	$602,957	$635,879	$560,647	$595,688	$628,212	($6,895)	($7,269)	($7,667)
4	Thrift Plan	Schedule 15	$2,426,402	$2,513,267	$2,589,419	$2,398,472	$2,484,577	$2,559,860	($27,930)	($28,690)	($29,559)
5	FAS 112 / ASC 712	Schedule 16	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Service Company Rents	Schedule 17	$13,285,082	$13,656,706	$13,442,382	$13,117,011	$13,497,420	$13,887,951	($168,071)	($159,286)	$445,569
7	Joint Facilities	Schedule 18	$1,065,547	$1,093,891	$1,120,473	$1,176,621	$1,207,920	$1,237,272	$111,074	$114,029	$116,799
8	Uninsured Claims	Schedule 19	$1,858,628	$1,908,068	$1,954,434	$1,840,172	$1,889,121	$1,935,026	($18,456)	($18,947)	($19,408)
9	Insurance Premium	Schedule 20	$2,090,894	$2,146,512	$2,198,672	$2,090,894	$2,146,512	$2,198,672	$0	$0	$0
10	Regulatory Assessment Fees	Schedule 21	$4,286,454	$4,286,454	$4,286,454	$4,286,454	$4,286,454	$4,286,454	$0	$0	$0
11	Uncollectible Accounts	Schedule 22	$4,122,270	$4,305,737	$4,356,617	$4,122,270	$4,279,125	$4,329,551	$0	($26,612)	($27,066)
12	Postage	Schedule 23	$2,557,424	$2,625,451	$2,689,250	$2,557,424	$2,625,451	$2,689,250	$0	$0	$0
13	Strike Contingency	Schedule 24	$8,573	$8,573	$8,573	$8,573	$8,801	$9,015	$0	$228	$442
14	Environmental Response Fund	Schedule 25	$3,078,000	$3,078,000	$3,078,000	$3,078,000	$3,078,000	$3,078,000	$0	$0	$0
15	Paperless Bill Credit	Schedule 26	$551,281	$551,281	$551,281	$551,281	$551,281	$551,281	$0	$0	$0
16	PBOP	Schedule 27	$4,901,371	$4,901,371	$4,901,371	$4,815,932	$4,815,932	$4,815,932	($85,439)	($85,439)	($85,439)
17	Pension	Schedule 28	$6,233,401	$5,075,109	$3,988,824	$6,000,874	$4,842,582	$3,756,296	($232,527)	($232,527)	($232,528)
18	Energy Efficiency Program	Schedule 29	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$38,809,400	$39,834,291	$40,795,469	$37,880,827	$38,881,018	$39,819,031	($928,573)	($953,273)	($976,438)
20	Storm Cost Recovery	Schedule 31	$7,023,726	$7,023,726	$7,023,726	$7,023,726	$7,023,726	$7,023,726	$0	$0	$0
21	Gas Commodity OM	Schedule 32	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	NEP IFA Credit	Schedule 33	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Wheeling	Schedule 34	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$186,193	$153,798	$153,798	$186,193	$153,798	$153,798	$0	$0	$0
25	Gas Business Enablement	Schedule 36	$460,685	$476,534	$457,527	$482,041	$511,352	$494,859	$21,356	$34,818	$37,332
26	Electric Operations	Schedule 37	$611,550	$572,000	$618,083	$611,550	$572,000	$618,083	$0	$0	$0
27	Gas Operations	Schedule 38	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Customer Affordability Program	Schedule 39	$613,623	$543,256	$288,128	$613,623	$543,256	$288,128	$0	$0	$0
29	Sub Total		$152,904,072	$155,607,719	$157,214,281	$150,603,295	$153,248,571	$155,409,000	($2,300,777)	($2,359,148)	($1,805,281)
30											
31	Purchased Power/ Purchased Gas	Schedule 40	$0	$0	$0	$0	$0	$0	$0	$0	$0
32											
33	Sub Total		$0	$0	$0	$0	$0	$0	$0	$0	$0
34											
35	TOTAL		$152,904,072	$155,607,719	$157,214,281	$150,603,298	$153,248,572	$155,409,002	($2,300,774)	($2,359,147)	($1,805,279)

The Narragansett Electric Company d/b/a National Grid
Summary of Adjustments - Settlement Filing to Compliance Filing
ELECTRIC Operation & Maintenance Expense

	Labor	
1	**Settlement Balance**	**$51,707,475**
2	Remove RE Growth labor captured in Docket 4748 (PUC 3-32/PUC Decision)	($347,134)
3	Additional Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($315,185)
4	Remove lobbying costs (Record request 1-4)	($178,815)
5	Remove Band A non-financial variable pay (Rebuttal adjustment)	($112,087)
6	Update 2018 non-union wage increase from 3.0% to 3.25% (Rebuttal adjustment)	$69,444
7	Adjusted O&M % for balance sheet adjustments (accounts 242/184) (PUC 1-31)	($13,192)
8	Additional rebuttal adjustments	($825)
9	FTE Smoothing (Rebuttal adjustment)/Remove CEI Marketing Analyst double-counted in Customer Affordability Program (DIV 3-7/DIV 3-9)	($395)
10	**Compliance Balance**	**$50,809,286**
11		
12	**Health Care**	
13	**Settlement Balance**	**$6,458,547**
14	Labor flow-through	($67,122)
15	**Compliance Balance**	**$6,391,424**
16		
17	**Group Life Insurance**	
18	**Settlement Balance**	**$567,542**
19	Remove lobbying costs (Record Request 1-4); labor flow-through	($6,895)
20	**Compliance Balance**	**$560,647**
21		
22	**Thrift Plan**	
23	**Settlement Balance**	**$2,426,402**
24	Remove lobbying costs (Record request 1-4); labor flow-through	($27,930)
25	**Compliance Balance**	**$2,398,472**
26		
27	**Service Company Rents**	
28	**Settlement Balance**	**$13,285,082**
29	Revised IS forecast (DIV 38-1)	($276,029)
30	Microsoft SaaS Contract/Renewal (Rebuttal adjustment)	$107,958
31	**Compliance Balance**	**$13,117,011**
32		
33	**Joint Facilities**	
34	**Settlement Balance**	**$1,065,547**
35	Reclass of IFA Rents adjustment (Rebuttal adjustment)	$130,387
36	Removal of Airplane charge from Joint Facilities (Rebuttal adjustment)	($19,313)
37	**Compliance Balance**	**$1,176,621**
38		
39	**Uninsured Claims**	
40	**Settlement Balance**	**$1,858,628**
41	Labor flow-through	($18,456)
42	**Compliance Balance**	**$1,840,172**
43		
44	**PBOP**	
45	**Settlement Balance**	**$4,901,371**
46	Labor flow-through	($85,439)
47	**Compliance Balance**	**$4,815,932**
48		
49	**Pension**	
50	**Settlement Balance**	**$6,233,401**
51	Labor flow-through	($232,527)
52	**Compliance Balance**	**$6,000,874**
53		
54	**Other Operating and Maintenance Expenses**	
55	**Settlement Balance**	**$38,809,400**
56	Contractors - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($748,196)
57	Donations - remove all charitable contributions as disallowed (PUC Decision)	($606,735)
58	Third Party Rents - Reclass of IFA Rents adjustment (Rebuttal adjustment)	$531,517
59	Other Benefits - Reclass labor portion of RE Growth costs to labor (PUC 3-32/PUC Decision)	$331,214
60	Contractors - Contact Voltage - remove from base rates to recover through ISR (Rebuttal adjustment)	($231,986)
61	Consultants - Remove lobbying costs (Record request 1-4)	($105,882)
62	Employee Expenses - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($103,094)
63	Contractors - Update RE Growth costs to most recent filing, Docket 4748 (PUC Decision)	$3,142
64	Other - Update RE Growth costs to most recent filing, Docket 4748 (PUC Decision)	$1,887
65	Consultants - Update RE Growth costs to most recent filing, Docket 4748 (PUC Decision)	($441)
66	**Compliance Balance**	**$37,880,827**
67		
68	**Gas Business Enablement**	
69	**Settlement Balance**	**$460,685**
70	Revised project forecast with change in allocations (DIV 17-13)	$21,356
71	**Compliance Balance**	**$482,041**
72		
73	Total Settlement balance for items above	$127,774,080
74	Total Compliance balance for items above	$125,473,307
75	Total change in O&M expense (agrees to Page 2, Line 35)	($2,300,773)

The Narragansett Electric Company d/b/a National Grid
Rate Base Calculation - Electric

		Settlement			Compliance			Delta		
	Description	Rate Year Ending August 31, 2019 (a)	Rate Year Ending August 31, 2020 (b)	Rate Year Ending August 31, 2021 (c)	Rate Year Ending August 31, 2019 (d)	Rate Year Ending August 31, 2020 (e)	Rate Year Ending August 31, 2021 (f)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Rate Year Ending August 31, 2020 (h)=(e)-(b)	Rate Year Ending August 31, 2021 (i)=(f)-(c)
1	Utility Plant In Service	$1,601,539,723	$1,602,539,723	$1,604,539,723	$1,601,539,723	$1,602,539,723	$1,604,539,723	($0)	$0	$0
2										
3	Property Held for Future Use	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$2,496,405	$0	$0	$0
4	Less: Contribution in Aid of Construction	$2,756	$2,756	$2,756	$2,756	$2,756	$2,756	($0)	$0	$0
5	Less: Accumulated Depreciation	$688,355,184	$688,470,384	$688,563,184	$688,355,184	$688,470,384	$688,563,184	($0)	$0	$0
6										
7	Net Plant	$915,678,188	$916,562,988	$918,470,188	$915,678,188	$916,562,988	$918,470,188	$0	$0	$0
8										
9	Materials and Supplies	$3,493,676	$3,403,498	$3,327,193	$3,493,676	$3,403,498	$3,327,193	($0)	$0	$0
10	Prepayments	$0	$0	$0	$0	$0	$0	$0	$0	$0
11	Loss on Reacquired Debt	$1,401,214	$1,244,585	$1,112,052	$1,401,214	$1,244,585	$1,112,052	($0)	$0	$0
12	Cash Working Capital	$17,043,665	$17,043,665	$17,043,665	$17,922,078	$17,922,078	$17,922,078	$878,413	$878,413	$878,413
13	Unamortized Interest Rate Lock	$1,638,006	$1,237,463	$898,542	$1,638,006	$1,237,463	$898,542	$0	$0	$0
14	Unamortized Debt Issuance Costs $550M	$901,943	$795,916	$706,200	$901,943	$795,916	$706,200	$0	$0	$0
15	Unamortized Debt Issuance Costs $250M	$866,236	$826,723	$793,290	$866,236	$826,723	$793,290	$0	$0	$0
16	Unamortized Debt Issuance Costs $350M	$848,309	$801,319	$774,113	$577,476	$511,041	$454,826	($270,833)	($290,278)	($319,287)
17	Subtotal	$26,193,050	$25,353,168	$24,655,055	$26,800,630	$25,941,303	$25,214,181	$607,580	$588,135	$559,126
18										
19	Accumulated Deferred FIT	$203,540,205	$201,385,915	$199,252,781	$203,540,205	$201,385,915	$199,252,781	$0	$0	$0
20	Accumulated Deferred FIT -Loss on Reacquired Debt	$540,073	$509,711	$479,349	$540,073	$509,711	$479,349	($0)	($0)	($0)
21	Customer Deposits	$8,888,568	$9,011,230	$9,115,021	$8,888,568	$9,011,230	$9,115,021	($0)	$0	$0
22	Subtotal	$212,968,847	$210,906,856	$208,847,151	$212,968,847	$210,906,856	$208,847,151	$0	($0)	($0)
23										
24	Rate Base	$728,902,391	$731,009,300	$734,278,092	$729,509,971	$731,597,435	$734,837,218	$607,580	$588,135	$559,126

Line Notes

12(g) (h) (i) - Change in Cash Working Capital caused by (1) $1.8 million increase to correct error in Settlement filing; CWC was calculated on total O&M of $133.3 million , which should have been calculated on $148.7 million (total $152.9 million minus uncollectible expense of $4.2 million). Results in an increase of $1.85 million in CWC from Settlement ; (2) decrease in O&M expense from Settlement to Compliance drives a decrease of $275,000; and (3) decrease in tax expense drives a decrease of $691,000 from Settlement.

16(g) (h) (i) - Change in Unamortized debt issuance costs related to new debt issued in July 2018. Original estimate of $2.3 million over a 30 year term; revised to $1.6 million over a 10 year term.

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

		Settlement			Compliance			Delta		
		Rate Year Ending August 31, 2019 (a)	Base Revenue Increase Required (b)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (c)=(a)+(b)	Rate Year Ending August 31, 2019 (d)	Base Revenue Increase Required (e)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (f)=(d)+(e)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Base Revenue Increase Required (h)=(e)-(b)	Rate Year Ending August 31, 2019 with Base Revenue (i)=(f)-(c)
1	Revenues	$214,523,590	$5,598,282	$220,121,872	$212,811,375	$5,823,471	$218,634,846	($1,712,215)	$225,189	($1,487,026)
2										
3	Purchased Power & Other Reconciling Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0
4										
5	Net Distribution Revenues	$214,523,590	$5,598,282	$220,121,872	$212,811,375	$5,823,471	$218,634,846	($1,712,215)	$225,189	($1,487,026)
6										
7	Operation & Maintenance Expenses	$87,171,898	$106,784	$87,278,682	$86,147,527	$111,079	$86,258,606	($1,024,372)	$4,295	($1,020,077)
8										
9	Amortization of Regulatory Deferrals	$1,520,606	$0	$1,520,606	$1,577,216	$0	$1,577,216	$56,611	$0	$56,611
10										
11	Amortization of Utility Plant	$426,184	$0	$426,184	$426,184	$0	$426,184	$0	$0	$0
12										
13	Depreciation	$39,136,909	$0	$39,136,909	$39,136,909	$0	$39,136,909	($0)	$0	($0)
14										
15	Municipal Taxes	$26,869,455	$0	$26,869,455	$26,869,455	$0	$26,869,455	$0	$0	$0
16										
17	Payroll Taxes	$2,738,063	$0	$2,738,063	$2,660,389	$0	$2,660,389			
18										
19	Gross Receipts Taxes	$0	$0	$0	$0	$0	$0	$0	$0	$0
20										
21	Other Taxes	$227,533	$0	$227,533	$227,533	$0	$227,533	$0	$0	$0
22										
23	Interest on Customer Deposits	$35,184	$0	$35,184	$35,184	$0	$35,184	$0	$0	$0
24										
25	Total Operating Revenue Deductions	$158,125,832	$106,784	$158,232,616	$157,080,397	$111,079	$157,191,476	($1,045,435)	$4,295	($1,041,140)
26										
27	Operating Income Before Income Taxes	$56,397,758	$5,491,498	$61,889,256	$55,730,978	$5,712,392	$61,443,370	($666,780)	$220,894	($445,886)
28										
29	Income Taxes	$5,930,858	$1,153,215	$7,084,072	$5,863,385	$1,199,602	$7,062,987	($67,473)	$46,388	($21,085)
30										
31	Operating Income After Income Taxes	$50,466,900	$4,338,284	$54,805,184	$49,867,593	$4,512,790	$54,380,383	($599,307)	$174,506	($424,801)
32										
33	Rate Base	$762,241,779		$762,241,779	$760,564,795		$760,564,795	($1,676,984)		($1,676,984)
34										
35	Rate of Return	6.62%	Line 31(a) / Line 33(a)		6.56%	Line 31(d) / Line 33(d)				
36										
37										
38	Revenue Deficiency									
39	Earned Rate of Return	6.62%	Line 35(a)		6.56%	Line 35(d)		-0.06%		
40	Rate Year Required Rate of Return	7.19%	Attachment 2, Schedule 1 GAS, Page 4, Line 9(c)		7.15%	Compliance Attachment 2, Schedule 1-ELEC, Page 4, Line		-0.04%		
41	Rate of Return Deficiency	0.57%	Line 40(a) - Line 39(a)		0.59%	Line 40(d) - Line 39(d)		0.02%		
42	Rate Base	$762,241,779	Line 33(a)		$760,564,795	Line 33(d)		($1,676,984)		
43	Net Operating Income Deficiency	$4,338,284			$4,512,790			$174,506		
44	Gross Revenue Conversion Factor	1.290437	Line 53(a)		1.290437	Line 53(d)		1.2904		
45	**Revenue Deficiency**	$5,598,282	Line 43(a) * Line 44(a)		$5,823,471	Line 43(d) * Line 44(d)		$225,189		
46										
47	Gross Revenue Conversion Factor									
48	Gross Revenue	1.000000			1.000000					
49	Uncollectible expense	(0.019074)	Attachment 2, Schedule 22, Page 6, Line 15		(0.019074)	Compliance Attachment 2, Schedule 22, Page 6, Line 15				
50	Revenue net of Uncollectibles	0.980926			0.980926					
51	Composite income tax rate	(0.205994)	Line 50(a) x (- 0.21%)		(0.205994)	Line 50(d) x (- 21%)				
52	Net income effect of 1.000 Revenue	0.774931	Line 50(a) + Line 51(a)		0.774931	Line 50(d) + Line 51(d)				
53	Gross Revenue Conversion Factor	1.290437	1 / Line 52(a)		1.290437	1 / Line 52(d)				

Line Notes:
Line 1 - decrease in rate year ISR revenues due to tax reform (lower tax rate, elimination of bonus depreciation and lower pre-tax return on rate base)
Line 9 - increase in projected rate case expenses (Record request 39)
Line 7 - refer to Pages 6 and 7
Line 33 - refer to Page 8

The Narragansett Electric Company d/b/a National Grid
Operating Expenses by Component
Summary - GAS

			Settlement			Compliance			Delta		
			Rate Year Ending August 31, 2019	Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2019	Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2021	Rate Year Ending August 31, 2019	Rate Year Ending August 31, 2020	Rate Year Ending August 31, 2021
	Operation & Maintenance Expenses:	Schedule Reference	(a)	(b)	(c)	(d)	(e)	(f)	(g)=(d)-(a)	(h)=(e)-(b)	(i)=(f)-(c)
1	Labor	Schedule 12	$33,465,578	$34,873,821	$35,939,787	$33,330,840	$34,742,707	$35,832,453	($134,738)	($131,114)	($107,334)
2	Health Care	Schedule 13	$4,342,511	$4,525,331	$4,663,806	$4,340,172	$4,524,195	$4,666,255	($2,339)	($1,136)	$2,449
3	Group Life Insurance	Schedule 14	$428,909	$458,375	$483,539	$425,237	$454,578	$479,898	($3,672)	($3,797)	($3,641)
4	Thrift Plan	Schedule 15	$1,525,431	$1,589,652	$1,638,295	$1,517,362	$1,581,698	$1,631,363	($8,069)	($7,954)	($6,932)
5	FAS 112 / ASC 712	Schedule 16	$0	$0	$0	$0	$0	$0	$0	$0	$0
6	Service Company Rents	Schedule 17	$4,461,616	$4,661,533	$4,633,242	$4,535,777	$4,755,618	$4,755,358	$74,161	$94,085	$122,116
7	Joint Facilities	Schedule 18	$587,447	$603,073	$617,728	$581,346	$596,810	$611,313	($6,101)	($6,263)	($6,415)
8	Uninsured Claims	Schedule 19	$644,861	$662,015	$678,102	$639,463	$656,472	$672,425	($5,398)	($5,543)	($5,677)
9	Insurance Premium	Schedule 20	$921,924	$946,365	$968,693	$921,924	$946,365	$968,693	$0	$0	$0
10	Regulatory Assessment Fees	Schedule 21	$1,897,662	$1,897,662	$1,897,662	$1,897,662	$1,897,662	$1,897,662	$0	$0	$0
11	Uncollectible Accounts	Schedule 22	$3,396,670	$3,503,454	$3,607,057	$3,396,670	$3,507,749	$3,616,983	$0	$4,295	$9,926
12	Postage	Schedule 23	$1,372,817	$1,409,334	$1,443,580	$1,372,817	$1,409,334	$1,443,580	$0	$0	$0
13	Strike Contingency	Schedule 24	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Environmental Response Fund	Schedule 25	$0	$0	$0	$0	$0	$0	$0	$0	$0
15	Paperless Bill Credit	Schedule 26	$265,235	$265,235	$265,235	$265,235	$265,235	$265,235	$0	$0	$0
16	PBOP	Schedule 27	($1,190,723)	($1,190,723)	($1,190,723)	($1,225,024)	($1,225,024)	($1,225,024)	($34,301)	($34,301)	($34,301)
17	Pension	Schedule 28	$3,356,606	$2,573,610	$1,840,992	$3,273,350	$2,490,355	$1,757,736	($83,256)	($83,255)	($83,256)
18	Energy Efficiency Program	Schedule 29	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Other Operating and Maintenance Expenses	Schedule 30	$27,414,855	$28,140,630	$28,820,179	$26,601,038	$27,305,166	$27,964,413	($813,817)	($835,464)	($855,766)
20	Storm Cost Recovery	Schedule 31	$0	$0	$0	$0	$0	$0	$0	$0	$0
21	Gas Commodity OM	Schedule 32	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	NEP IFA Credit	Schedule 33	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	Wheeling	Schedule 34	$0	$0	$0	$0	$0	$0	$0	$0	$0
24	Energy Innovation Hub	Schedule 35	$101,186	$83,581	$83,581	$101,186	$83,581	$83,581	$0	$0	$0
25	Gas Business Enablement	Schedule 36	$2,854,116	$3,290,713	$3,333,456	$2,847,275	$3,511,995	$3,665,243	($6,841)	$221,282	$331,787
26	Electric Operations	Schedule 37	$0	$0	$0	$0	$0	$0	$0	$0	$0
27	Gas Operations	Schedule 38	$1,032,482	$955,700	$955,700	$1,032,482	$955,700	$955,700	$0	$0	$0
28	Customer Affordability Program	Schedule 39	$292,714	$295,232	$156,583	$292,714	$295,232	$156,583	$0	$0	$0
29	Sub Total		$87,171,897	$89,544,593	$90,836,494	$86,147,527	$88,755,428	$90,199,451	($1,024,370)	($789,165)	($637,043)
30											
31	Purchased Power/ Purchased Gas	Schedule 40	$0	$0	$0	$0	$0	$0	$0	$0	$0
32											
33	Sub Total		$0	$0	$0	$0	$0	$0	$0	$0	$0
34											
35	TOTAL		$87,171,898	$89,544,592	$90,836,494	$86,147,527	$88,755,428	$90,199,451	($1,024,371)	($789,164)	($637,043)

The Narragansett Electric Company d/b/a National Grid
Summary of Adjustments - Settlement Filing to Compliance Filing
GAS Operation & Maintenance Expense

1	**Labor**	
2	**Settlement Balance**	**$33,465,578**
3	Additional Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($148,124)
4	Remove Band A non-financial variable pay (Rebuttal adjustment)	($67,953)
5	CoRecord requestect union wage increase calculation (Rebuttal adjustment)	$58,082
6	Update 2018 non-union wage increase from 3.0% to 3.25% (Rebuttal adjustment)	$37,963
7	Remove lobbying costs (Record request 1-4)	($21,916)
8	FTE smoothing (Rebuttal adjustment)/Remove CEI Marketing Analyst double-counted in Customer Affordability Program (DIV 3-7 / DIV 3-9)	$7,587
9	CoRecord requestect variable pay normalizing adjustment (Rebuttal adjustment)	($376)
10	**Compliance Balance**	**$33,330,840**
11		
12	**Health Care**	
13	**Settlement Balance**	**$4,342,511**
14	Labor flow-through	($2,339)
15	**Compliance Balance**	**$4,340,172**
16		
17	**Group Life Insurance**	
18	**Settlement Balance**	**$428,909**
19	Remove lobbying costs (Record request 1-4); labor flow-through	($3,672)
20	**Compliance Balance**	**$425,237**
21		
22	**Thrift Plan**	
23	**Settlement Balance**	**$1,525,431**
24	Remove lobbying costs (Record request 1-4); labor flow-through	($8,069)
25	**Compliance Balance**	**$1,517,362**
26		
27	**Service Company Rents**	
28	**Settlement Balance**	**$4,461,616**
29	Revised IS forecast (DIV 38-1)	$31,582
30	Microsoft SaaS Contract/Renewal (Rebuttal adjustment)	$42,579
31	**Compliance Balance**	**$4,535,777**
32		
33	**Joint Facilities**	
34	**Settlement Balance**	**$587,447**
35	Removal of Airplane charge from Joint Facilities (Rebuttal adjustment)	($6,101)
36	**Compliance Balance**	**$581,346**
37		
38	**Uninsured Claims**	
39	**Settlement Balance**	**$644,861**
40	Labor flow-through	($5,399)
41	**Compliance Balance**	**$639,463**
42		
43	**PBOP**	
44	**Settlement Balance**	**($1,190,723)**
45	Labor flow-through	($34,301)
46	**Compliance Balance**	**($1,225,024)**
47		
48	**Pension**	
49	**Settlement Balance**	**$3,356,606**
50	Labor flow-through	($83,256)
51	**Compliance Balance**	**$3,273,350**
52		
53	**Other Operating and Maintenance Expenses**	
54	**Settlement Balance**	**$27,414,855**
55	Contractors - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($410,505)
56	Donations - remove all charitable contributions as disallowed (PUC Decision)	($315,697)
57	Employee Expenses - Service Company A&G overhead study adjustment (DIV 21-10 Supplemental)	($60,824)
58	Consultants - Remove lobbying costs (Record request 1-4)	($26,791)
59	**Compliance Balance**	**$26,601,038**
60		
61	**Gas Business Enablement**	
62	**Settlement Balance**	**$2,854,116**
63	Change in Allocations from Finance (DIV 17-13)	($6,841)
64	**Compliance Balance**	**$2,847,275**
65		
66	Total Settlement balance for items above	$77,891,207
67	Total Compliance balance for items above	$76,866,836
68	Total change in O&M expense (agrees to Page 6, Line 35)	($1,024,371)

The Narragansett Electric Company d/b/a National Grid
Rate Base Summary - Gas

		Settlement			Compliance			Delta		
	Description	Rate Year 1 Ending August 31, 2019 (a)	Data Year 1 Ending August 31, 2020 (b)	Data Year 2 Ending August 31, 2021 (c)	Rate Year 1 Ending August 31, 2019 (d)	Data Year 1 Ending August 31, 2020 (e)	Data Year 2 Ending August 31, 2021 (f)	Rate Year Ending August 31, 2019 (g)=(d)-(a)	Rate Year Ending August 31, 2020 (h)=(e)-(b)	Rate Year Ending August 31, 2021 (i)=(f)-(c)
1	Gas Plant In Service	$1,306,857,054	$1,328,015,869	$1,349,443,902	$1,306,857,054	$1,328,015,869	$1,349,443,902	($0)	($0)	($0)
2	Normalizing Adjustment: Smallworld GIS[1]	$3,996,550	$3,996,550	$3,996,550	$3,996,550	$3,996,550	$3,996,550	$0	$0	$0
3	Gas Plant In Service	$1,310,853,604	$1,332,012,419	$1,353,440,452	$1,310,853,604	$1,332,012,419	$1,353,440,451	($0)	($0)	($0)
4										
5	Construction Work In Progress	$44,213,371	$45,444,229	$46,739,869	$44,213,371	$45,444,229	$46,739,869	$0	$0	$0
6										
7	Less: Accumulated Depreciation	$427,173,934	$428,191,816	$429,895,395	$427,173,934	$428,191,816	$429,895,395	$0	$0	$0
8	Normalizing Adjustment: Smallworld GIS[1]	$2,987,945	$3,414,129	$3,840,314	$2,987,945	$3,414,129	$3,840,314	$0	$0	$0
9	Test Year Adjusted Accumulated Depreciation	$430,161,879	$431,605,945	$433,735,709	$430,161,879	$431,605,945	$433,735,709	$0	$0	$0
10										
11	Less: Contribution in Aid of Construction	($946)	($2,250)	($3,622)	($946)	($2,250)	($3,622)	$0	$0	$0
12										
13	Net Plant	$924,906,042	$945,852,952	$966,448,234	$924,906,042	$945,852,952	$966,448,234	($0)	($0)	($0)
14										
15	Additions:									
16	Materials and Supplies	$2,680,174	$2,159,157	$1,610,719	$2,680,174	$2,159,157	$1,610,719	$0	$0	$0
17	Prepaid Expenses, Excluding Taxes	$204,501	$276,014	$351,290	$204,501	$276,014	$351,290	$0	$0	$0
18	Deferred Debits	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	Cash Working Capital	$6,502,325	$6,502,325	$6,502,325	$6,672,954	$6,672,954	$6,672,954	$170,629	$170,629	$170,629
20	Unamortized Interest Lock expense $550M	$717,273	$555,375	$393,477	$717,273	$555,375	$393,477	$0	$0	$0
21	Unamortized Issuance Costs $300M	$368,550	$351,035	$333,519	$368,550	$351,035	$333,519	$0	$0	$0
22	Unamortized Issuance Costs $250M	$26,397	$4,434	$0	$26,397	$4,434	$0	$0	$0	$0
23	Unamortized Issuance Costs $200M	$251,932	$241,287	$230,642	$251,932	$241,287	$230,642	$0	$0	$0
24	Unamortized Issuance Costs $250M	$2,302,437	$2,279,062	$2,255,687	$454,825	$406,525	$358,225	($1,847,612)	($1,872,537)	($1,897,462)
25	Unamortized Issuance Costs Mortgage Bonds	$54,229	$31,304	$8,379	$54,229	$31,304	$8,379	$0	$0	$0
26	Total Additions	$13,107,818	$12,399,994	$11,686,040	$11,430,834	$10,698,085	$9,959,206	($1,676,984)	($1,701,909)	($1,726,834)
27										
28	Deductions:									
29	Accumulated Deferred FIT	$155,641,847	$165,481,552	$172,638,610	$155,641,847	$165,481,552	$172,638,610	($0)	($0)	($0)
30	Merger Hold Harmless Adjustment	$18,662,756	$16,576,053	$14,145,381	$18,662,756	$16,576,053	$14,145,381	$0	$0	$0
31	Customer Deposits	$1,467,477	$1,208,830	$936,570	$1,467,477	$1,208,830	$936,570	$0	$0	$0
32	Total Deductions	$175,772,080	$183,266,434	$187,720,560	$175,772,080	$183,266,434	$187,720,560	($0)	($0)	($0)
33										
34	Rate Base	$762,241,779	$774,986,512	$790,413,714	$760,564,795	$773,284,603	$788,686,880	($1,676,984)	($1,701,909)	($1,726,834)
35										
36	Total Rate Base	$762,241,779	$774,986,512	$790,413,714	$760,564,795	$773,284,603	$788,686,880	($1,676,984)	($1,701,909)	($1,726,834)

[1]Gas Information System

Line Notes

19(g) (h) (i) - Change in Cash Working Capital caused by (1) $450,000 increase to correct error in Settlement filing; CWC was calculated on total O&M of $78.8 million , which should have been calculated on $83.8 million (total $87.2 million minus uncollectible expense of $3.4 million). Results in an increase of $450,00 in CWC from Settlement ; (2) decrease in O&M expense from Settlement to Compliance drives a decrease of $92,000; and (3) decrease in tax expense drives a decrease of $187,000 from Settlement.

24(g) (h) (i) - Change in Unamortized debt issuance costs related to (1) settlement rate base erroneously included total unamortized issuance costs instead of the gas-only portion - decrease of $1.62 million; and (2) revised estimate of issuance costs in July 2018. Settlement included estimated issuance costs of $2.3 million over a 30 year term; revised to $1.6 million over a 10 year term for compliance - decrease of $225,000.

Compliance Attachment 1

Narragansett Electric and Narragansett Gas Revenue Requirement Settlement Terms

Rate Years 1, 2, 3

The Narragansett Electric Company
d/b/a National Grid
Summary of Revenue Requirement Settlement Terms
Revenue Increases
($ million)

Incremental Revenue

	Narragansett Electric	Narragansett Gas	Total
Base case			
Rate Year 1	$12.0	$5.8	$17.8
Rate Year 2	$3.9	$5.7	$9.6
Rate Year 3	$2.5	$3.4	$5.9
Subtotal	$18.4	$14.9	$33.3
Power Sector Transformation (PST)			
Rate Year 1	$2.1	$0.0	$2.1
Rate Year 2	$6.6	$1.9	$8.4
Rate Year 3	$1.9	$0.6	$2.5
Subtotal - PST	$10.6	$2.5	$13.0
Base Case plus PST			
Rate Year 1	$14.1	$5.8	$19.9
Rate Year 2	$10.5	$7.6	$18.0
Rate Year 3	$4.3	$4.0	$8.4
TOTAL	$28.9	$17.4	$46.3

Revenue Requirement

	Narragansett Electric	Narragansett Gas	Total
Base case			
Rate Year 1	$291.1	$218.6	$509.7
Rate Year 2	$295.0	$224.3	$519.3
Rate Year 3	$297.5	$227.7	$525.2
Subtotal	$883.6	$670.6	$1,554.2
Power Sector Transformation (PST)			
Rate Year 1	$2.1	$0.0	$2.1
Rate Year 2	$8.7	$1.9	$10.6
Rate Year 3	$10.6	$2.5	$13.0
Subtotal - PST	$21.3	$4.4	$25.7
Base Case plus PST			
Rate Year 1	$293.2	$218.6	$511.8
Rate Year 2	$303.6	$226.2	$529.9
Rate Year 3	$308.0	$230.2	$538.2
TOTAL	$904.9	$675.0	$1,579.9

The Narragansett Electric Company Summary of Revenue Requirement Settlement Terms Revenue Increases and Cost of Service Adjustments	($ Millions) TOTAL Rate Year	Rate Year 2	Rate Year 3
1 Company Position per REV-1 filing (March 2)	$45.8		
2 Refund of Excess Deferred taxes	($9.0)		
3 Admin & General expense reclass to capital	($4.5)		
3a Company Position adjusted	$32.4		
Settlement Adjustments:			
4 Unfunded Service Co Excess Deferred taxes (3 pt allocator over 3 years)	$3.1		
5 ROE @ 9.275%	($8.0)		
6 Accept Division's adjustment for capital structure and Gas debt rates	($0.9)		
6a Partially accept Division's adjustment to depreciation rates	($3.1)		
7 Adjust Service Company Rents & GBE for reduced ROE at 9.275%	($0.3)		
8 Accept Division's adjustment for GBE (15% slippage, Type II savings)	($1.1)		
9 Accept Division's adjustment for IS (15% slippage)	($0.6)		
10 Accept Division's adjustment for Gas uncollectibles rate	($0.3)		
11 Company's shaping of incremental DG-related FTEs over 3 years	($0.2)		
12 Company's shaping of other incremental FTEs over 3 years	($0.8)		
13 Depreciation expense impact of Growth adjustment	($0.2)		
Amended Settlement Adjustments:			
14 Discovery/Rebuttal adjustments (REV-2) not previously reflected in Settlement	($0.3)		
15 Remove lobbying costs (Record request 1-4)	($0.4)		
16 Remove charitable donations (PUC Decision)	($0.9)		
17 Revised capital structure, debt expense and debt issuance costs	($0.3)		
18 Sub-Total of Expense Adjustments	**($14.3)**	**$0.0**	**$0.0**
Rate base Adjustments:			
19 Partially accept Division's adjustment on Growth forecast	($7.8)		
20 Depreciation Reserve flow through of Growth Adjustment	$0.2		
21 ADIT flow through of Growth Adjustment	$1.0		
22 Excess Deferred Income taxes	$3.5		
23 Sub-Total of Rate base Adjustments	($3.1)	$0.0	$0.0
24 Pre-Tax Return %			
25 Revenue Requirement on Rate base Adjustments	($0.3)		
26 **Total Adjustments**	**($14.6)**	**$0.0**	**$0.0**
27 **Subtotal - Base Rate request adjusted [Note 1]**	**$17.8**	**$9.6**	**$5.9**
Add-ins for PST:			
28 AMI Study at $2M	$0.7	$0.0	$0.0
29 GIS investment (IS)	$0.1	$0.0	$0.0
30 GIS investment (BR)	$0.0	$1.0	$0.0
31 DSCADA	$0.0	$0.4	($0.4)
32 System Data Portal - accept 2/3 in RY, up to 3 FTEs in Year 2	$0.5	$0.2	$0.0
33 All other Grid Mod (excluding DSCADA, GIS, SDP, Feeder Monitoring)	$0.0	$6.2	$1.8
34 Sub-Total of PST Adjustments - Grid Modernization Programs	**$1.3**	**$7.9**	**$1.3**
35 Electric Transportation	$0.7	$0.5	$1.0
36 Electric heat	$0.0	$0.0	$0.0
37 Strategic electrification education fund	$0.0	$0.0	$0.0
38 Storage	$0.1	$0.1	$0.2
39 Sub-Total of PST Adjustments - Special Sector Programs	**$0.8**	**$0.6**	**$1.2**
40 Sub-Total of PST Adjustments	**$2.1**	**$8.5**	**$2.5**
41 **Total Settlement - Base Case plus PST**	**$19.8**	**$18.0**	**$8.4**

Note 1 : The derivation of Rate Year 2 and Rate Year 3 revenue increases are per Pages 4 and 5 of this Attachment.

$ 46.3

The Narragansett Electric Company Summary of Revenue Requirement Settlement Terms Revenue Increases and Cost of Service Adjustments	($ Millions) ELECTRIC Rate Year	 Rate Year 2	 Rate Year 3
1 Company Position per REV-1 filing (March 2)	$27.4		
2 Refund of Excess Deferred taxes	($6.5)		
3 Admin & General expense reclass to capital	($3.0)		
3a Company Position adjusted	$17.9		
Settlement Adjustments:			
4 Unfunded Service Co Excess Deferred taxes (3 pt allocator over 3 years)	$2.3		
5 ROE @ 9.275%	($3.9)		
6 Accept Division's adjustment for capital structure and Gas debt rates	($0.3)		
6a Partially accept Division's adjustment to depreciation rates	($0.9)		
7 Adjust Service Company Rents & GBE for reduced ROE at 9.275%	($0.2)		
8 Accept Division's adjustment for GBE (15% slippage, Type II savings)	($0.2)		
9 Accept Division's adjustment for IS (15% slippage)	($0.4)		
10 Accept Division's adjustment for Gas uncollectibles rate	$0.0		
11 Company's shaping of incremental DG-related FTEs over 3 years	($0.2)		
12 Company's shaping of other incremental FTEs over 3 years	($0.3)		
13 Depreciation expense impact of Growth adjustment	$0.0		
Amended Settlement Adjustments:			
14 Discovery/Rebuttal adjustments (REV-2) not previously reflected in Settlement	($1.2)		
15 Remove lobbying costs (Record request 1-4)	($0.3)		
16 Remove charitable donations (PUC Decision)	($0.6)		
17 Revised capital structure, debt expense and debt issuance costs	$0.0		
18 Sub-Total of Expense Adjustments	**($6.1)**	**$0.0**	**$0.0**
Rate base Adjustments:			
19 Partially accept Division's adjustment on Growth forecast	$0.0		
20 Depreciation Reserve flow through of Growth Adjustment	$0.0		
21 ADIT flow through of Growth Adjustment	$0.0		
22 Excess Deferred Income taxes	$2.5		
23 Sub-Total of Rate base Adjustments	$2.5	$0.0	$0.0
24 Pre-Tax Return %	8.23%		
25 Revenue Requirement on Rate base Adjustments	$0.2		
26 **Total Adjustments**	**($5.9)**	**$0.0**	**$0.0**
27 **Subtotal - Base Rate request adjusted [Note 1]**	**$12.0**	**$3.9**	**$2.5**
Add-ins for PST:			
28 AMI Study at $2M	$0.7	$0.0	$0.0
29 GIS investment (IS)	$0.1	$0.0	$0.0
30 GIS investment (BR)	$0.0	$1.0	$0.0
31 DSCADA	$0.0	$0.4	($0.4)
32 System Data Portal - accept 2/3 in RY, up to 3 FTEs in Year 2	$0.5	$0.2	$0.0
33 All other Grid Mod (excluding DSCADA, GIS, SDP, Feeder Monitoring)	$0.0	$4.3	$1.2
34 Sub-Total of PST Adjustments - Grid Modernization Programs	**$1.3**	**$6.0**	**$0.7**
35 Electric Transportation	$0.7	$0.5	$1.0
36 Electric heat	$0.0	$0.0	$0.0
37 Strategic electrification education fund	$0.0	$0.0	$0.0
38 Storage	$0.1	$0.1	$0.2
39 Sub-Total of PST Adjustments - Special Sector Programs	**$0.8**	**$0.6**	**$1.2**
40 Sub-Total of PST Adjustments	**$2.1**	**$6.6**	**$1.9**
41 **Total Settlement - Base Case plus PST**	**$14.1**	**$10.5**	**$4.3**
Note 1 : The derivation of Rate Year 2 and Rate Year 3 revenue increases are per Pages 4 and 5 of this Attachment.		$	28.9

The Narragansett Electric Company **Summary of Revenue Requirement Settlement Terms** **Revenue Increases and Cost of Service Adjustments**		**($ Millions)** **GAS** **Rate Year**	**Rate Year 2**	**Rate Year 3**
1	Company Position per REV-1 filing (March 2)	$18.4		
2	Refund of Excess Deferred taxes	($2.5)		
3	Admin & General expense reclass to capital	($1.5)		
3a	Company Position adjusted	$14.4		
Settlement Adjustments:				
4	Unfunded Service Co Excess Deferred taxes (3 pt allocator over 3 years)	$0.8		
5	ROE @ 9.275%	($4.1)		
6	Accept Division's adjustment for capital structure and Gas debt rates	($0.6)		
6a	Partially accept Division's adjustment to depreciation rates	($2.2)		
7	Adjust Service Company Rents & GBE for reduced ROE at 9.275%	($0.1)		
8	Accept Division's adjustment for GBE (15% slippage, Type II savings)	($1.0)		
9	Accept Division's adjustment for IS (15% slippage)	($0.2)		
10	Accept Division's adjustment for Gas uncollectibles rate	($0.3)		
11	Company's shaping of incremental DG-related FTEs over 3 years	$0.0		
12	Company's shaping of other incremental FTEs over 3 years	($0.5)		
13	Depreciation expense impact of Growth adjustment	($0.2)		
Amended Settlement Adjustments:				
14	Discovery/Rebuttal adjustments (REV-2) not previously reflected in Settlement	$0.9		
15	Remove lobbying costs (Record request 1-4)	($0.1)		
16	Remove charitable donations (PUC Decision)	($0.3)		
17	Revised capital structure, debt expense and debt issuance costs	($0.3)		
18	**Sub-Total of Expense Adjustments**	**($8.2)**	**$0.0**	**$0.0**
Rate base Adjustments:				
19	Partially accept Division's adjustment on Growth forecast	($7.8)		
20	Depreciation Reserve flow through of Growth Adjustment	$0.2		
21	ADIT flow through of Growth Adjustment	$1.0		
22	Excess Deferred Income taxes	$1.0		
23	Sub-Total of Rate base Adjustments	($5.6)	$0.0	$0.0
24	Pre-Tax Return %	8.41%		
25	Revenue Requirement on Rate base Adjustments	($0.5)		
26	**Total Adjustments**	**($8.7)**	**$0.0**	**$0.0**
27	**Subtotal - Base Rate request adjusted [Note 1]**	**$5.8**	**$5.7**	**$3.4**
	Add-ins for PST:			
28	AMI Study at $2M	$0.0	$0.0	$0.0
29	GIS investment (IS)	$0.0	$0.0	$0.0
30	GIS investment (BR)	$0.0	$0.0	$0.0
31	DSCADA	$0.0	$0.0	$0.0
32	System Data Portal - accept 2/3 in RY, up to 3 FTEs in Year 2	$0.0	$0.0	$0.0
33	All other Grid Mod (excluding DSCADA, GIS, SDP, Feeder Monitoring)	$0.0	$1.9	$0.6
34	**Sub-Total of PST Adjustments - Grid Modernization Programs**	**$0.0**	**$1.9**	**$0.6**
35	Electric Transportation	$0.0	$0.0	$0.0
36	Electric heat	$0.0	$0.0	$0.0
37	Strategic electrification education fund	$0.0	$0.0	$0.0
38	Storage	$0.0	$0.0	$0.0
39	**Sub-Total of PST Adjustments - Special Sector Programs**	**$0.0**	**$0.0**	**$0.0**
40	**Sub-Total of PST Adjustments**	**$0.0**	**$1.9**	**$0.6**
41	**Total Settlement - Base Case plus PST**	**$5.8**	**$7.7**	**$4.0**

Note 1 : The derivation of Rate Year 2 and Rate Year 3 revenue increases are per Pages 4 and 5 of this Attachment.

$ 17.4

The Narragansett Electric Company d/b/a National Grid
Revenue Increases--Rate Years 2 & 3
Electric

Adjusted to exclude impact of items that would otherwise be collected through ISR factors in Rate Years 2 & 3

			Adjustments to Reflect Conditions in Rate Year 2	Adjustments to Reflect Conditions in Rate Year 3
			Electric	Electric
			(a)	(b)
	Operation & Maintenance Expenses:	Schedule		
1	Labor and related benefits	12 through 16	$2,174,993	$1,901,853
2	Service Company Rents	17	$380,409	$390,531
3	All other O&M expenses	various	($16,556)	($149,207)
4	Total Operation & Maintenance expense		$2,538,846	$2,143,177
5				
6	Incremental Depreciation & Amortization	4-ELEC	$879,921	$44,250
7	Incremental Taxes Other than Income taxes	8 & 9	$120,968	$96,490
8	Incremental Interest on Customer Deposits	Wkp 2	$172,340	($4,308)
9				
10	Return & Taxes on Incremental Rate Base	8.23%	$158,236	$266,548
11	**Revenue Deficiency**		**$3,870,311**	**$2,546,157**

The Narragansett Electric Company d/b/a National Grid
Revenue Increases--Rate Years 2 & 3
Gas
Adjusted to exclude impact of items that would otherwise be collected through ISR factors in Rate Years 2 & 3

			Adjustments to Reflect Conditions in Rate Year 2	Adjustments to Reflect Conditions in Rate Year 3
			Gas	Gas
			(a)	(b)
	Operation & Maintenance Expenses:	Schedule		
1	Labor and related benefits	12 through 16	$1,689,568	$1,306,791
2	Service Company Rents	17	$219,840	($260)
3	Gas Business Enablement	36	$664,720	$153,248
4	All other O&M expenses	various	$31,929	($60,847)
5	Total Operation & Maintenance expense		$2,606,057	$1,398,932
6				
7	Incremental Depreciation & Amortization	4-GAS	$1,924,745	$608,784
8	Incremental Taxes Other than Income taxes	8 & 9	$80,670	$61,307
9	Incremental Interest on Customer Deposits	Wkp 2	$45,892	($1,147)
10				
11	Return & Taxes on Incremental Rate Base	8.41%	$1,069,398	$1,294,921
12	**Revenue Deficiency**		**$5,726,762**	**$3,362,798**

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
PST Annual Revenue Requirement Summary Electric - Synergy

Line No.			Rate Year	Rate Year 2	Rate Year 3
GRID MOD					
	Electric Capex				
1	Feeder Monitoring Sensor		$0	$0	$0
2	RTU Separation		$0	$124,147	$209,992
3	**Electric Capex Total**		**$0**	**$124,147**	**$209,992**
	IS Capex - Electric Only				
4	Enterprise Service Bus		$0	$0	$436,827
5	Data Lake		$0	$46,245	$42,925
6	PI Historian		$0	$23,044	$21,390
7	Advanced Analytics		$0	$519,374	$651,192
8	Telecommunications		$0	$20,077	$27,060
9	Cybersecurity		$0	$658,484	$835,826
10	DSCADA		$0	$0	$0
11	**Electric IS Capex Total**		**$0**	**$1,267,224**	**$2,015,220**
	O&M - Electric Only				
12	Enterprise Service Bus		$0	$402,346	$504,066
13	Data Lake		$0	$388,092	$545,532
14	PI Historian		$0	$515,000	$515,000
15	Advanced Analytics		$0	$299,978	$338,852
16	Telecommunications		$0	$425,022	$636,886
17	Cybersecurity		$0	$802,100	$623,280
18	DSCADA		$0	$0	$0
19	Feeder Monitoring Sensor		$0	$0	$0
20	RTU Separation		$0	$60,000	$60,000
21	GIS Data Enhancements (BR)		$0	$0	$0
22	GIS Data Enhancements (IS)		$0	$0	$0
23	System Data Portal		$0	$0	$0
24	**Electric O&M Total**		**$0**	**$2,892,538**	**$3,223,615**
25	**Subtotal - all other Grid Mod**		**$0**	**$4,283,910**	**$5,448,828**
TOTAL PST					
26	AMI Study	($2M over 3 years)	$666,667	$666,667	$666,667
27	GIS Data Enhancements (IS)	($427,000 over 3 years)	$142,333	$142,333	$142,333
28	GIS Data Enhancements (BR)	(as filed)	$0	$1,028,000	$1,028,000
29	DSCADA	(as filed)	$0	$436,000	$0
30	System Data Portal	(2 FTEs in RY, 3 FTEs by RY2)	$466,667	$700,000	$700,000
31	All other Grid Mod excl. FM, DSCADA, GIS & SDP		$0	$4,283,910	$5,448,828
32	**Subtotal - Grid Modernization**		**$1,275,667**	**$7,256,910**	**$7,985,828**
33	Electric Transporation	(SSP settlement)	$681,300	$1,151,751	$2,151,776
34	Electric Heat	(SSP settlement)	$0	$0	$0
35	Strategic Elec Education Fund	(SSP settlement)	$7,500	$11,250	$18,750
36	Storage	(SSP settlement)	$112,856	$259,668	$411,986
37	**Subtotal - Special Sector Programs**		**$801,656**	**$1,422,669**	**$2,582,511**
38	**Total PST proposal - Electric**		**$2,077,322**	**$8,679,579**	**$10,568,339**
39	Revenue Increases		$2,077,322	$6,602,256	$1,888,760

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
PST Annual Revenue Requirement Summary Gas - Synergy

Line No.		0 Rate Year	Rate Year 2	Rate Year 3
GRID MOD				
	Gas Capex			
1	Feeder Monitoring Sensor	$0	$0	$0
2	RTU Separation	$0	$0	$0
3	**Gas Capex Total**	**$0**	**$0**	**$0**
	IS Capex - Gas Only			
4	Enterprise Service Bus	$0	$0	$237,393
5	Data Lake	$0	$25,132	$23,327
6	PI Historian	$0	$0	$0
7	Advanced Analytics	$0	$282,253	$353,889
8	Telecommunications	$0	$10,911	$14,706
9	Cybersecurity	$0	$357,852	$454,228
10	DSCADA	$0	$0	$0
11	**Gas IS Capex Total**	**$0**	**$676,148**	**$1,083,543**
	O&M - Gas Only			
12	Enterprise Service Bus	$0	$218,654	$273,934
13	Data Lake	$0	$210,908	$296,468
14	PI Historian	$0	$0	$0
15	Advanced Analytics	$0	$163,022	$184,148
16	Telecommunications	$0	$230,978	$346,114
17	Cybersecurity	$0	$435,900	$338,720
18	DSCADA	$0	$0	$0
19	Feeder Monitoring Sensor	$0	$0	$0
20	RTU Separation	$0	$0	$0
21	GIS Data Enhancements (BR)	$0	$0	$0
22	GIS Data Enhancements (IS)	$0	$0	$0
23	System Data Portal	$0	$0	$0
24	**Gas O&M Total**	**$0**	**$1,259,462**	**$1,439,385**
25	**Subtotal - all other Grid Mod**	**$0**	**$1,935,610**	**$2,522,928**
TOTAL PST				
26	AMI Study	$0	$0	$0
27	GIS Data Enhancements (IS)	$0	$0	$0
28	GIS Data Enhancements (BR)	$0	$0	$0
29	DSCADA	$0	$0	$0
30	System Data Portal	$0	$0	$0
31	All other Grid Mod excl. FM, DSCADA, GIS & SDP	$0	$1,935,610	$2,522,928
32	**Subtotal - Grid Modernization**	**$0**	**$1,935,610**	**$2,522,928**
33	Electric Transporation	$0	$0	$0
34	Electric Heat	$0	$0	$0
35	Strategic Elec Education Fund	$0	$0	$0
36	Storage	$0	$0	$0
37	**Subtotal - Special Sector Programs**	**$0**	**$0**	**$0**
38	**Total PST proposal - Gas**	**$0**	**$1,935,610**	**$2,522,928**
39	Revenue Increases	$0	$1,935,610	$587,318

The Narragansett Electric Company
d/b/a National Grid
Power Sector Transformation (PST)
PST Annual Revenue Requirement Summary Total RI - Synergy

Line No.		Rate Year	Rate Year 2	Rate Year 3
	GRID MOD			
	Total RI Capex			
1	Feeder Monitoring Sensor	$0	$0	$0
2	RTU Separation	$0	$124,147	$209,992
3	**Total RI Capex Total**	**$0**	**$124,147**	**$209,992**
	IS Capex - Total RI Only			
4	Enterprise Service Bus	$0	$0	$674,220
5	Data Lake	$0	$71,377	$66,252
6	PI Historian	$0	$23,044	$21,390
7	Advanced Analytics	$0	$801,627	$1,005,081
8	Telecommunications	$0	$30,988	$41,766
9	Cybersecurity	$0	$1,016,336	$1,290,054
10	DSCADA	$0	$0	$0
11	**Total RI IS Capex Total**	**$0**	**$1,943,372**	**$3,098,763**
	O&M - Total RI Only			
12	Enterprise Service Bus	$0	$621,000	$778,000
13	Data Lake	$0	$599,000	$842,000
14	PI Historian	$0	$515,000	$515,000
15	Advanced Analytics	$0	$463,000	$523,000
16	Telecommunications	$0	$656,000	$983,000
17	Cybersecurity	$0	$1,238,000	$962,000
18	DSCADA	$0	$0	$0
19	Feeder Monitoring Sensor	$0	$0	$0
20	RTU Separation	$0	$60,000	$60,000
21	GIS Data Enhancements (BR)	$0	$0	$0
22	GIS Data Enhancements (IS)	$0	$0	$0
23	System Data Portal	$0	$0	$0
24	**Total RI O&M Total**	**$0**	**$4,152,000**	**$4,663,000**
25	**Subtotal - all other Grid Mod**	**$0**	**$6,219,519**	**$7,971,755**
	TOTAL PST			
26	AMI Study	$666,667	$666,667	$666,667
27	GIS Data Enhancements (IS)	$142,333	$142,333	$142,333
28	GIS Data Enhancements (BR)	$0	$1,028,000	$1,028,000
29	DSCADA	$0	$436,000	$0
30	System Data Portal	$466,667	$700,000	$700,000
31	All other Grid Mod excl. FM, DSCADA, GIS & SDP	$0	$6,219,519	$7,971,755
32	**Subtotal - Grid Modernization**	**$1,275,667**	**$9,192,519**	**$10,508,755**
33	Electric Transporation	$681,300	$1,151,751	$2,151,776
34	Electric Heat	$0	$0	$0
35	Strategic Elec Education Fund	$7,500	$11,250	$18,750
36	Storage	$112,856	$259,668	$411,986
37	**Subtotal - Special Sector Programs**	**$801,656**	**$1,422,669**	**$2,582,511**
38	**Total PST proposal - RI**	**$2,077,322**	**$10,615,188**	**$13,091,267**
39	Revenue Increases	$2,077,322	$8,537,866	$2,476,078

Compliance Attachment 2
Schedules 1 -13

Compliance Attachment 2

Narragansett Electric and Narragansett Gas Revenue Requirements

Rate Years 1, 2, 3

Compliance Filing
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COMPLIANCE ATTACHMENT 2

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Compliance Attachment 2

Schedule 1-ELEC

Revenue Requirement– Electric

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line		Schedule Reference	Test Year Ended June 30, 2017	Normalizing Adjustments	Test Year Ended June 30, 2017 Adjusted	Proforma Adjustments	Rate Year Ending August 31, 2019	Base Revenue Increase Required	Rate Year Ending August 31, 2019 with Base Revenue Requirement
			(a)	(b)	(c) = (a) + (b)	(c)	(e) = (c) + (d)	(f)	(g) = (e) + (f)
1	Revenues	Schedule 2-ELEC	$906,848,280	($627,513,858)	$279,334,422	($242,479)	$279,091,943	$12,038,936	$291,130,879
2									
3	Purchased Power & Other Reconciling Expense	Schedule 3	$304,255,398	($304,255,398)	$0	$0	$0	$0	$0
4									
5	Net Distribution Revenues		$602,592,882	($323,258,459)	$279,334,422	($242,479)	$279,091,943	$12,038,936	$291,130,879
6									
7	Operation & Maintenance Expenses	Schedule 3	$304,575,180	($164,238,756)	$140,336,424	$10,266,874	$150,603,298	$156,855	$150,760,152
8									
9	Amortization of Regulatory Deferrals	Schedule 4-ELEC	$8,454	($8,454)	$0	$471,908	$471,908	$0	$471,908
10									
11	Amortization of Utility Plant	Schedule 5-ELEC	$62,962	($62,962)	$0	$0	$0	$0	$0
12									
13	Depreciation	Schedule 6-ELEC	$69,031,187	($19,869,812)	$49,161,375	$966,957	$50,128,332	$0	$50,128,332
14									
15	Municipal Taxes	Schedule 7-ELEC	$49,702,787	($20,023,313)	$29,679,474	$850,784	$30,530,258	$0	$30,530,258
16									
17	Payroll Taxes	Schedule 8	$8,148,712	($4,435,908)	$3,712,803	$441,719	$4,154,522	$0	$4,154,522
18									
19	Gross Receipts Taxes	Schedule 9	$32,568,650	($32,568,650)	$0	$0	$0	$0	$0
20									
21	Other Taxes	Schedule 9	$434,298	$0	$434,298	$20,108	$454,406	$0	$454,406
22									
23	Interest on Customer Deposits	Workpaper 2-ELEC	$0	$0	$0	$132,127	$132,127	$0	$132,127
24									
25	Total Operating Revenue Deductions		$464,532,229	($241,207,855)	$223,324,374	$13,150,477	$236,474,851	$156,855	$236,631,706
26									
27	Operating Income Before Income Taxes		$138,060,652	($82,050,604)	$56,010,048	($13,392,956)	$42,617,092	$11,882,081	$54,499,173
28									
29	Income Taxes	Schedule 10-ELEC					$1,157,091	$2,495,237	$3,652,328
30									
31	Operating Income After Income Taxes						$41,460,001	$9,386,844	$50,846,845
32									
33	Rate Base	Schedule 11-ELEC					$729,509,971		$729,509,971
34									
35	Rate of Return						5.68%	Line 31(e) / Line 33(e)	
36									
37									

Line			
38	Revenue Deficiency		
39	Earned Rate of Return	5.68%	Line 35 (e)
40	Rate Year Required Rate of Return	6.97%	Page 4, Line 9 (c)
41	Rate of Return Deficiency	1.29%	Line 40 - Line 39
42	Rate Base	$729,509,971	Line 33 (e)
43	Net Operating Income Deficiency	$9,386,844	
44	Gross Revenue Conversion Factor	1.282533	Line 53
45	**Revenue Deficiency**	$12,038,936	Line 43 / Line 44
46			
47	Gross Revenue Conversion Factor		
48	Gross Revenue	1.000000	
49	Uncollectible expense	(0.013029)	Schedule 22, Page 6, Line 15
50	Revenue net of Uncollectibles	0.986971	
51	Composite income tax rate	(0.20726)	Line 50 x (- 21%)
52	Net income effect of 1.000 Revenue	0.779707	Line 50 + Line 51
53	Gross Revenue Conversion Factor	1.2825328	1 / Line 52

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2019 to Rate Year Ending August 31, 2020

Line		Schedule Reference	Rate Year Ending August 31, 2019	Reflect Conditions in the Rate Year	Rate Year Ending August 31, 2020	Base Revenue Increase Required	Rate Year Ending August 31, 2020 with Base Revenue Requirement
			(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
1	Revenues	Schedule 2-ELEC	$291,130,879	$0	$291,130,879	$3,870,311	$295,001,190
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$291,130,879	$0	$291,130,879	$3,870,311	$295,001,190
6							
7	Operation & Maintenance Expenses	Schedule 3	$150,760,152	$2,488,420	$153,248,572	$50,426	$153,298,998
8							
9	Amortization of Regulatory Deferrals	Schedule 4-ELEC	$471,908	$0	$471,908	$0	$471,908
10							
11	Amortization of Utility Plant	Schedule 5-ELEC	$0	$0	$0	$0	$0
12							
13	Depreciation	Schedule 6-ELEC	$50,128,332	$879,921	$51,008,253	$0	$51,008,253
14							
15	Municipal Taxes	Schedule 7-ELEC	$30,530,258	$0	$30,530,258	$0	$30,530,258
16							
17	Payroll Taxes	Schedule 8	$4,154,522	$108,881	$4,263,404	$0	$4,263,404
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$454,406	$12,087	$466,493	$0	$466,493
22							
23	Interest on Customer Deposits	Workpaper 2-ELEC	$132,127	$172,340	$304,467	$0	$304,467
24							
25	Total Operating Revenue Deductions		$236,631,706	$3,661,649	$240,293,355	$50,426	$240,343,781
26							
27	Operating Income Before Income Taxes		$54,499,173	($3,661,649)	$50,837,523	$3,819,885	$54,657,408
28							
29	Income Taxes	Schedule 10-ELEC			$2,862,891	$802,176	$3,665,067
30							
31	Operating Income After Income Taxes				$47,974,632	$3,017,709	$50,992,341
32							
33	Rate Base	Schedule 11-ELEC			$731,597,435		$731,597,435
34							
35	Rate of Return				6.56%	Line 31(c) / Line 33(c)	

Line			
36			
37			
38	Revenue Deficiency		
39	Earned Rate of Return	6.56%	Line 35 (c)
40	Rate Year Required Rate of Return	6.97%	Page 4, Line 9 (c)
41	Rate of Return Deficiency	0.41%	Line 40 - Line 39
42	Rate Base	$731,597,435	Line 33 (c)
43	Net Operating Income Deficiency	$3,017,709	
44	Gross Revenue Conversion Factor	1.282533	Line 53
45	**Revenue Deficiency**	$3,870,311	Line 43 / Line 44
46			
47	Gross Revenue Conversion Factor		
48	Gross Revenue	1.000000	
49	Uncollectible expense	(0.013029)	Schedule 22, Page 6, Line 15
50	Revenue net of Uncollectibles	0.986971	
51	Composite income tax rate	(0.20726)	Line 50 x (- 21%)
52	Net income effect of 1.000 Revenue	0.779707	Line 50 + Line 51
53	Gross Revenue Conversion Factor	1.2825328	1 / Line 52

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Electric Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2020 to Rate Year Ending August 31, 2021

Line		Schedule Reference	Rate Year Ending August 31, 2021	Reflect Conditions in the Rate Year	Rate Year Ending August 31, 2021 Adjusted	Base Revenue Increase Required	Rate Year Ending August 31, 2021 with Base Revenue Requirement
			(a)	(b)	(c) = (a) + (b)	(d)	(e) = (c) + (d)
1	Revenues	Schedule 2-ELEC	$295,001,190	$0	$295,001,190	$2,546,157	$297,547,347
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$295,001,190	$0	$295,001,190	$2,546,157	$297,547,347
6							
7	Operation & Maintenance Expenses	Schedule 3	$153,298,998	$2,110,003	$155,409,002	$33,174	$155,442,175
8							
9	Amortization of Regulatory Deferrals	Schedule 4-ELEC	$471,908	$0	$471,908	$0	$471,908
10							
11	Amortization of Utility Plant	Schedule 5-ELEC	$0	$0	$0	$0	$0
12							
13	Depreciation	Schedule 6-ELEC	$51,008,253	$44,250	$51,052,503	$0	$51,052,503
14							
15	Municipal Taxes	Schedule 7-ELEC	$30,530,258	$0	$30,530,258	$0	$30,530,258
16							
17	Payroll Taxes	Schedule 8	$4,263,404	$85,155	$4,348,558	$0	$4,348,558
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$466,493	$11,336	$477,829	$0	$477,829
22							
23	Interest on Customer Deposits	Workpaper 2-ELEC	$304,467	($4,308)	$300,158	$0	$300,158
24							
25	Total Operating Revenue Deductions		$240,343,781	$2,246,435	$242,590,217	$33,174	$242,623,390
26							
27	Operating Income Before Income Taxes		$54,657,408	($2,246,435)	$52,410,973	$2,512,983	$54,923,956
28							
29	Income Taxes	Schedule 10-ELEC			$3,178,076	$527,726	$3,705,802
30							
31	Operating Income After Income Taxes				$49,232,897	$1,985,257	$51,218,154
32							
33	Rate Base	Schedule 11-ELEC			$734,837,218		$734,837,218
34							
35	Rate of Return				6.70%	Line 31(c) / Line 33(c)	
36							
37							

38	Revenue Deficiency		
39	Earned Rate of Return	6.70%	Line 35 (c)
40	Rate Year Required Rate of Return	6.97%	Page 4, Line 9 (c)
41	Rate of Return Deficiency	0.27%	Line 40 - Line 39
42	Rate Base	$734,837,218	Line 33 (c)
43	Net Operating Income Deficiency	$1,985,257	
44	Gross Revenue Conversion Factor	1.282533	Line 53
45	**Revenue Deficiency**	$2,546,157	Line 43 / Line 44
46			
47	Gross Revenue Conversion Factor		
48	Gross Revenue	1.000000	
49	Uncollectible expense	(0.013029)	Schedule 22, Page 6, Line 15
50	Revenue net of Uncollectibles	0.986971	
51	Composite income tax rate	(0.20726)	Line 50 x (- 21%)
52	Net income effect of 1.000 Revenue	0.779707	Line 50 + Line 51
53	Gross Revenue Conversion Factor	1.2825328	1 / Line 52

The Narragansett Electric Company d/b/a National Grid
Cost of Capital
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2021

	Description	Capital Structure	Cost Rate	Weighted Return	Taxes	Pre-tax Return
		(a)	(b)	(c) = (a) x (b)	(d)	(e) = (c)+(d)
1	Short Term Debt	0.60%	1.76%	0.01%		0.01%
2						
3	Long Term Debt	48.35%	4.62% (1)	2.23%		2.23%
4						
5	Preferred Stock	0.10%	4.50%	0.00%		0.00%
6						
7	Total Common Equity	50.95%	9.275%	4.73%	1.26% (2)	5.99%
8						
9	Total Capitalization	100.00%		6.97%	1.26%	8.23%

Notes
(1) Company's Effective Cost of Long Term Debt
(2) Line 3(c) / (1-21%) - Line 3(c)

Column Notes
(a) As referenced in Pre-filed Direct Testimony of Robert B. Hevert, page 2 of 2 Lines 14 through 18

Line Notes
1(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 13
3(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 4
5(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 10
7(b) Based on Settlement

Compliance Attachment 2

Schedule 1-GAS

Revenue Requirement – Gas

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

Line	Description	Schedule Reference	Test Year Ended June 30, 2017 (a)	Normalizing Adjustments (b)	Test Year Ended June 30, 2017 Adjusted (c) = (a) + (b)	Proforma Adjustments (d)	Rate Year Ending August 31, 2019 (e) = (c) + (d)	Base Revenue Increase Required (f)	Rate Year Ending August 31, 2019 with Base Revenue Requirement (g) = (e) + (f)
1	Revenues	Schedule 2-GAS	$377,158,225	($199,714,435)	$177,443,790	$35,367,585	$212,811,375	$5,823,471	$218,634,846
2									
3	Purchased Power & Other Reconciling Expense	Schedule 3	$136,269,302	($136,269,302)	$0	$0	$0	$0	$0
4									
5	Net Distribution Revenues		$240,888,923	($63,445,133)	$177,443,790	$35,367,585	$212,811,375	$5,823,471	$218,634,846
6									
7	Operation & Maintenance Expenses	Schedule 3	$115,479,365	($28,084,501)	$87,394,863	($1,247,337)	$86,147,527	$111,079	$86,258,606
8									
9	Amortization of Regulatory Deferrals	Schedule 4-GAS	$705,953	$1,309,738	$2,015,691	($438,475)	$1,577,216	$0	$1,577,216
10									
11	Amortization of Utility Plant	Schedule 5-GAS	$1,874,224	$106,546	$1,980,770	($1,554,586)	$426,184	$0	$426,184
12									
13	Depreciation	Schedule 6-GAS	$33,311,851	($15,649)	$33,296,202	$5,840,707	$39,136,909	$0	$39,136,909
14									
15	Municipal Taxes	Schedule 7-GAS	$22,542,352	($453,318)	$22,089,035	$4,780,420	$26,869,455	$0	$26,869,455
16									
17	Payroll Taxes	Schedule 8	($1,294,241)	$3,762,248	$2,468,007	$192,382	$2,660,389	$0	$2,660,389
18									
19	Gross Receipts Taxes	Schedule 9	$11,166,309	($11,166,309)	$0	$0	$0	$0	$0
20									
21	Other Taxes	Schedule 9	$217,464	$0	$217,464	$10,069	$227,533	$0	$227,533
22									
23	Interest on Customer Deposits	Workpaper 2-GAS	$0	$0	$0	$35,184	$35,184	$0	$35,184
24									
25	Total Operating Revenue Deductions		$184,003,277	($34,541,245)	$149,462,033	$7,618,364	$157,080,397	$111,079	$157,191,476
26									
27	Operating Income Before Income Taxes		$56,885,646	($28,903,888)	$27,981,757	$27,749,221	$55,730,978	$5,712,392	$61,443,370
28									
29	Income Taxes	Schedule 10-GAS					$5,863,385	$1,199,602	$7,062,987
30									
31	Operating Income After Income Taxes						$49,867,593	$4,512,790	$54,380,383
32									
33	Rate Base	Schedule 11-GAS					$760,564,795		$760,564,795
34									
35	Rate of Return						6.56%	Line 31(e) / Line 33(e)	
36									
37									
38						Revenue Deficiency			
39						Earned Rate of Return	6.56%	Line 35 (e)	
40						Rate Year Required Rate of Return	7.15%	Page 4, Line 9 (c)	
41						Rate of Return Deficiency	0.59%	Line 40 - Line 39	
42						Rate Base	$760,564,795	Line 33 (e)	
43						Net Operating Income Deficiency	$4,512,790		
44						Gross Revenue Conversion Factor	1.290437	Line 53	
45						**Revenue Deficiency**	$5,823,471	Line 43 / Line 44	
46									
47						Gross Revenue Conversion Factor			
48						Gross Revenue	1.000000		
49						Uncollectible expense	(0.019074)	Schedule 22, Page 7, Line 15	
50						Revenue net of Uncollectibles	0.980926		
51						Composite income tax rate	(0.20599)	Line 50 x (- 21%)	
52						Net income effect of 1.000 Revenue	0.774931	Line 50 + Line 51	
53						Gross Revenue Conversion Factor	1.2904371	1 / Line 52	

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2019 to Rate Year Ending August 31, 2020

Line		Schedule Reference	Rate Year Ending August 31, 2019 (a)	Reflect Conditions in the Rate Year (b)	Rate Year Ending August 31, 2020 (c) = (a) + (b)	Base Revenue Increase Required (d)	Rate Year Ending August 31, 2020 with Base Revenue Requirement (e) = (c) + (d)
1	Revenues	Schedule 2-GAS	$218,634,846	$0	$218,634,846	$5,726,761	$224,361,607
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$218,634,846	$0	$218,634,846	$5,726,761	$224,361,607
6							
7	Operation & Maintenance Expenses	Schedule 3	$86,258,606	$2,496,823	$88,755,428	$109,234	$88,864,662
8							
9	Amortization of Regulatory Deferrals	Schedule 4-GAS	$1,577,216	$0	$1,577,216	$0	$1,577,216
10							
11	Amortization of Utility Plant	Schedule 5-GAS	$426,184	$0	$426,184	$0	$426,184
12							
13	Depreciation	Schedule 6-GAS	$39,136,909	$1,924,745	$41,061,654	$0	$41,061,654
14							
15	Municipal Taxes	Schedule 7-GAS	$26,869,455	$0	$26,869,455	$0	$26,869,455
16							
17	Payroll Taxes	Schedule 8	$2,660,389	$74,617	$2,735,007	$0	$2,735,007
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$227,533	$6,052	$233,585	$0	$233,585
22							
23	Interest on Customer Deposits	Workpaper 2-GAS	$35,184	$45,892	$81,076	$0	$81,076
24							
25	Total Operating Revenue Deductions		$157,191,476	$4,548,129	$161,739,605	$109,234	$161,848,840
26							
27	Operating Income Before Income Taxes		$61,443,370	($4,548,129)	$56,895,241	$5,617,527	$62,512,767
28							
29	Income Taxes	Schedule 10-GAS			$6,043,238	$1,179,681	$7,222,918
30							
31	Operating Income After Income Taxes				$50,852,003	$4,437,846	$55,289,849
32							
33	Rate Base	Schedule 11-GAS			$773,284,603		$773,284,603
34							
35	Rate of Return				6.58%	Line 31(c) / Line 33(c)	

Line			
36			
37			
38	Revenue Deficiency		
39	Earned Rate of Return	6.58%	Line 35 (c)
40	Rate Year Required Rate of Return	7.15%	Page 4, Line 9 (c)
41	Rate of Return Deficiency	0.57%	Line 40 - Line 39
42	Rate Base	$773,284,603	Line 33 (c)
43	Net Operating Income Deficiency	$4,437,846	
44	Gross Revenue Conversion Factor	1.290437	Line 53
45	**Revenue Deficiency**	$5,726,761	Line 43 / Line 44
46			
47	Gross Revenue Conversion Factor		
48	Gross Revenue	1.000000	
49	Uncollectible expense	(0.019074)	Schedule 22, Page 7, Line 15

The Narragansett Electric Company d/b/a National Grid
Illustrative Statement of Gas Operations Income and Revenue Deficiency Summary
For Rate Year Ending August 31, 2020 to Rate Year Ending August 31, 2021

Line		Schedule Reference	Rate Year Ending August 31, 2020 (a)	Reflect Conditions in the Rate Year (b)	Rate Year Ending August 31, 2020 Adjusted (c) = (a) + (b)	Base Revenue Increase Required (d)	Rate Year Ending August 31, 2021 with Base Revenue Requirement (e) = (c) + (d)
1	Revenues	Schedule 2-GAS	$224,361,607	$0	$224,361,607	$3,362,798	$227,724,405
2							
3	Purchased Power & Other Reconciling Expense	Schedule 3	$0	$0	$0	$0	$0
4							
5	Net Distribution Revenues		$224,361,607	$0	$224,361,607	$3,362,798	$227,724,405
6							
7	Operation & Maintenance Expenses	Schedule 3	$88,864,662	$1,334,789	$90,199,451	$64,143	$90,263,594
8							
9	Amortization of Regulatory Deferrals	Schedule 4-GAS	$1,577,216	$0	$1,577,216	$0	$1,577,216
10							
11	Amortization of Utility Plant	Schedule 5-GAS	$426,184	$0	$426,184	$0	$426,184
12							
13	Depreciation	Schedule 6-GAS	$41,061,654	$608,784	$41,670,438	$0	$41,670,438
14							
15	Municipal Taxes	Schedule 7-GAS	$26,869,455	$0	$26,869,455	$0	$26,869,455
16							
17	Payroll Taxes	Schedule 8	$2,735,007	$55,631	$2,790,638	$0	$2,790,638
18							
19	Gross Receipts Taxes	Schedule 9	$0	$0	$0	$0	$0
20							
21	Other Taxes	Schedule 9	$233,585	$5,676	$239,261	$0	$239,261
22							
23	Interest on Customer Deposits	Workpaper 2-GAS	$81,076	($1,147)	$79,929	$0	$79,929
24							
25	Total Operating Revenue Deductions		$161,848,840	$2,003,733	$163,852,572	$64,143	$163,916,716
26							
27	Operating Income Before Income Taxes		$62,512,767	($2,003,733)	$60,509,035	$3,298,655	$63,807,690
28							
29	Income Taxes	Schedule 10-GAS			$6,723,860	$692,718	$7,416,578
30							
31	Operating Income After Income Taxes				$53,785,175	$2,605,937	$56,391,112
32							
33	Rate Base	Schedule 11-GAS			$788,686,880		$788,686,880
34							
35	Rate of Return				6.82%	Line 31(c) / Line 33(c)	
36							
37							

38	Revenue Deficiency		
39	Earned Rate of Return	6.82%	Line 35 (c)
40	Rate Year Required Rate of Return	7.15%	Page 4, Line 9 (c)
41	Rate of Return Deficiency	0.33%	Line 40 - Line 39
42	Rate Base	$788,686,880	Line 33 (c)
43	Net Operating Income Deficiency	$2,605,937	
44	Gross Revenue Conversion Factor	1.290437	Line 53
45	**Revenue Deficiency**	$3,362,798	Line 43 / Line 44
46			
47	Gross Revenue Conversion Factor		
48	Gross Revenue	1.000000	
49	Uncollectible expense	(0.019074)	Schedule 22, Page 7, Line 15
50	Revenue net of Uncollectibles	0.980926	
51	Composite income tax rate	(0.20599)	Line 50 x (- 21%)
52	Net income effect of 1.000 Revenue	0.774931	Line 50 + Line 51
53	Gross Revenue Conversion Factor	1.2904371	1 / Line 52

The Narragansett Electric Company d/b/a National Grid
Cost of Capital
For the Test Year Ended June 30, 2017 and the Rate Year Ending August 31, 2019

	Description	Capital Structure	Cost Rate		Weighted Return	Taxes		Pre-tax Return
		(a)	(b)		(c) = (a) x (b)	(d)		(e) = (c)+(d)
1	Short Term Debt	0.60%	1.76%		0.01%			0.01%
2								
3	Long Term Debt	48.35%	4.98%	(1)	2.41%			2.41%
4								
5	Preferred Stock	0.10%	4.50%		0.00%			0.00%
6								
7	Total Common Equity	50.95%	9.275%		4.73%	1.26%	(2)	5.99%
8								
9	Total Capitalization	100.00%			7.15%	1.26%		8.41%

Notes
(1) Company's Effective Cost of Long Term Debt
(2) Line 3(c) / (1 - 21%) - Line 3(c)

Column Notes
(a) As referenced in Pre-filed Direct Testimony of Robert B. Hevert, page 2 of 2 Lines 14 through 18

Line Notes
1(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 13
3(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 4
5(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 78 of 93 Line 10
7(b) As referenced in Pre-filed Direct Testimony of Robert B. Hevert,, page 83 of 93 Line 13