nationalgrid

**Celia B. O'Brien**
Assistant General Counsel and Director

December 16, 2015

**VIA HAND DELIVERY & ELECTRONIC MAIL**

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

**RE: Docket 4568 – The Narragansett Electric Company d/b/a National Grid
Review of Electric Distribution Rate Design Pursuant to R.I. Gen. Laws § 39-26.6-24
National Grid Joint Rebuttal Testimony**

Dear Ms. Massaro:

On behalf of National Grid[1], I enclose ten (10) copies of the Company's joint rebuttal testimony of Peter T. Zschokke, Jeanne A. Lloyd, and Timothy R. Roughan in the above-referenced docket. The Company's rebuttal testimony primarily addresses the following:

1. Responds to comments and recommendations contained in the direct testimonies filed in this docket by the Division of Public Utilities and Carriers and several of the intervening parties;

2. Provides additional support for the Company's rate design proposals;

3. Regarding the proposed tiered customer charge, suggests for the PUC's consideration alternative ratchet provisions and a delay in implementation to educate customers about the operation of the new rate structure and rates; and

4. Includes an Access Fee "grandfathering" proposal for the PUC's consideration.

Thank you for your attention to this transmittal. If you have any questions concerning this filing, please contact me at 781-907-2153.

Very truly yours,

Celia B. O'Brien

Celia B. O'Brien

Enclosures

cc: Docket 4568 Service List
Steve Scialabba, Division
Richard Hahn, Division
Leo Wold, Esq.

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

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Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

___________________________________
Joanne M. Scanlon

December 16, 2015
Date

**Docket No. 4568 National Grid's Rate Design Pursuant to R.I. Gen. Laws Sec 39-26.6-24**
**Service List updated 11/23/15**

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# JOINT REBUTTAL TESTIMONY

# OF

# PETER T. ZSCHOKKE, JEANNE A. LLOYD

# AND

# TIMOTHY R. ROUGHAN

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## I. <u>Introduction and Qualifications</u>

**Q. Please state your name and business address.**

A. My name is Peter T. Zschokke. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

**Q. Have you previously submitted testimony in this proceeding?**

A. Yes.

**Q. Please state your full name and business address.**

A. My name is Jeanne A. Lloyd, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

**Q. Have you previously submitted testimony in this proceeding?**

A. Yes.

**Q. Mr. Roughan, please state your name and business address.**

A. My name is Timothy R. Roughan, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

**Q. Mr. Roughan, by whom are you employed and in what position?**

A. I am employed by National Grid USA Service Company, Inc. (the Service Company) as the Director of Energy and Environmental Policy. My responsibilities include providing regulatory and policy direction on issues relative to distributed generation (DG). I have worked extensively on procedures for interconnecting DG to National Grid USA subsidiaries' electric distribution systems both for Federal Energy Regulatory Commission (FERC) jurisdictional projects at the ISO New England (ISO-NE) and New York Independent System Operator level and for state jurisdictional projects in Rhode Island, Massachusetts, and New York.

**Q. Mr. Roughan, please describe your educational background and professional experience.**

A. I am a 1982 graduate of Worcester Polytechnic Institute with a Bachelor of Science in Mechanical Engineering and have worked for the Service Company or its predecessors for 32 years.

**Q. Have you previously testified before the Rhode Island Public Utilities Commission (PUC)?**

A. Yes. I have testified most recently in the Company's 2016 System Reliability Procurement Report proceeding (Docket No. 4581), the Company's fiscal year 2016 Electric Infrastructure, Safety, and Reliability (ISR) Plan proceeding (Docket No. 4539), and the tariff advice filing to amend RIPUC No. 2099, Net Metering Provision proceeding (Docket No. 4549). I also testified in the Company's 2015 System Reliability

Procurement Report proceeding (Docket No. 4528). In addition, I have been heavily involved in all interconnection tariff proceedings since 2007, with the latest proceeding taking place this past October in Docket No. 4483.

**Q. On whose behalf are you submitting rebuttal testimony in this proceeding?**

A. We are submitting our rebuttal testimony on behalf of the Company.

## II. <u>Purpose of Rebuttal Testimony</u>

**Q. Mr. Zschokke, Ms. Lloyd, and Mr. Roughan, what is the purpose of your joint rebuttal testimony?**

A. The purpose of our joint rebuttal testimony is to respond to the pre-filed direct testimonies submitted by the Division of Public Utilities and Carriers (Division) and several of the intervenors to this proceeding with regard to the Company's proposed rate design changes.

**Q. How is your testimony organized?**

A. Section III of our testimony responds to the criticisms regarding the Company's rate design proposals and recommendations set forth in the direct testimony filed by the Division and several of the intervenors in this proceeding. Specifically, this section of our testimony addresses (i) the consistency of the Company's proposal with the requirements of R.I. Gen. Laws § 39-26.6-24 (Section 24); (ii) the recommendation for a broad stakeholder process; (iii) intervenors' objections to alleviating the cross-subsidization of DG customers by non-DG customers; (iv) conclusions regarding the costs and benefits of DG; (v) the "complexity" of the Company's proposed rate design; and (vi) the intervenors' advocacy for time-of-use rates. Section IV addresses the issues raised regarding the Company's proposal to consolidate Rates G-32 and G-62. Section V responds to intervenors' criticisms of the proposed Access Fee and outlines a proposal to "grandfather" certain projects from the assessment of the Access Fee. Section VI explains how the Company considered the seven factors outlined in Section 24 which the PUC must take into account and balance in establishing any new rates it may deem appropriate, in developing its rate design proposals in this proceeding. Section VII is the conclusion to our testimony.

**Q. Are you sponsoring any schedules today?**

A. Yes, we are sponsoring the following schedules:

- Schedule NG-1-R — Typical Bill Residential A-16 Customer Showing Subsidies and Public Policy Programs
- Schedule NG-2-R — Company Response to Data Request WED 1-13
- Schedule NG-3-R — Typical Bill Showing 12 Months of Usage History
- Schedule NG-4-R — Typical Residential Bill – Electric Space Heating Customer
- Schedule NG-5-R — Typical Residential Bill – Customer with Electric Vehicle

## III. Response to Intervenors' Direct Testimony

**Q. Please respond generally to the criticism regarding the Company's rate design proposals and recommendations contained in the various testimonies of the intervening parties.**

A. Several of the intervening parties to this proceeding are renewable energy developers or renewable energy industry advocates that have recommended the PUC reject the Company's rate design proposal in its entirety. It is not surprising that advocates of renewable energy projects are opposed to the Company's proposals that may result in a revenue contribution from DG customers, where little or none currently exists. It is clearly in their best interest that rates are as low as possible for distributed energy resources (DER) participants as that will shorten the payback period for energy efficiency and DG investments.

However, the PUC must balance the interests of the DG community with the interests of the remaining customers throughout Rhode Island who are required to pay for the expansion of DG statewide through their delivery rates. Also, the PUC must balance the interests of the DG community and all other customers in ensuring those who receive value from use of the distribution system pay fairly and equitably for that use, including DG customers, as stated in the Company's original pre-filed direct testimony. The Act[1]

[1] R.I. Gen. Laws Ch. 39-26.6 (the Act).

establishes a framework for facilitating and promoting the installation of grid-connected DG and supporting and encouraging development of DG systems in Rhode Island, including the requirement in Section 24 that requires the PUC determine the appropriate cost responsibility and the fair and equitable contributions toward the operation, maintenance, and investment in the distribution system that is relied upon by all customers. These customers represent non-net metered and net-metered customers, including those with stand-alone generation. The imperative underlying Section 24's requirement for the PUC to establish a fair rate structure is that the growing DG energy sector is not contributing its fair share towards the costs of operating, maintaining, and investing in the system to which DG is interconnected.

It is important that all parties remember that Rhode Island has committed all electric customers to pay for DG for at least the next twenty years through the Long-Term Contracting Standard for Renewable Energy,[2] the DG Standard Contracts program,[3] and the Renewable Energy (RE) Growth Program[4] tariffs. That is part of the "value proposition" (i.e., the promise of benefits in the future for payment today) that underlies the state's policy goals of promoting DG through these statutory programs. The Company and state regulators have a shared obligation to ensure that what the

[2] R.I. Gen. Laws Ch. 39-26.1.
[3] R.I. Gen. Laws Ch. 39-26.2.
[4] R.I. Gen. Laws Ch. 39-26.6.

Company's customers pay for DG will be returned to them eventually in the form of benefits that are at least of equal value as the cost they must pay. That is an obligation the Company does not take lightly and has proposed a revenue neutral rate design consistent with the specific requirements and general intent of Section 24.

The Company recognizes that the costs and benefits of a developing industry, such as DG, are not always easy to calculate, since both are dependent upon many assumptions and factors that are likely to change over time. The reality is that the true value of the potential benefits of DG will likely not be known for years. However, the PUC has an opportunity in this proceeding to set the stage for responsible ratemaking, considering appropriate cost allocation and fair and equitable contributions all connecting customers make toward the recovery of distribution system costs. That means, in part, that the costs and potential benefits of DG related to the distribution system should be as transparent as possible to both DG and non-DG customers. Doing so will ensure that customers have the best information available to allow them to make informed economic decisions with regard to energy consumption and installation of distributed energy resources.

Intervenor Perspective Regarding Consistency of Company Proposal With the Act

**Q. Some intervenors argue that the Company's proposal is not consistent with the Act because it does not facilitate and promote distributed generation of renewable**

**energy (Besser Direct Testimony at Page 14, Golin Direct Testimony at Pages 22-23). Please comment.**

A. The Company's RE Growth Program, including the new SolarWise Program proposed as part of the 2016 Program, is designed to facilitate and promote the installation of DG, and meet all other goals the Act. Section 24 of the Act has a very specific purpose. Contrary to these intervenors' arguments, Section 24 does not require the rate design changes implemented pursuant to Section 24 to promote DG. The purpose of Section 24 is for the PUC to "determine the appropriate cost responsibility and contributions to the operation, maintenance, and investment in the distribution system that is relied upon by all customers, including, without limitation, non-net metered and net metered customers."[5] Thus, Section 24 requires the PUC to *balance* the goals of the Act that are intended to facilitate and promote DG with the other criteria specified in Section 24. Rates that are based upon sound economic principles will promote an efficient allocation of societal resources. The fact that the Company's proposals may result in some DG customers having to contribute more towards the costs of the distribution system upon which they rely than they do under the existing rate structure is not, in and of itself, a sound reason to reject the proposed rate structure. The legislature must have contemplated that increased contributions to distribution system costs by DG customers was a possible outcome of the rate design review proceeding when they required the PUC to open a docket to consider

[5] R.I. Gen. Laws § 39-26.6-24(a).

rate design and distribution cost allocation in light of net metering and increased distributed energy resources, including DG, which shifts more costs to non-DG customers. The Company's proposed rate changes will more fairly and equitably recover costs from all customers, thereby satisfying the intent of Section 24.

**Q. Does the Company agree with some of the intervenors (Gold Direct Testimony at Page 7, Besser Direct Testimony at Page 18) that the intent of Section 24 has been met if the PUC rejects the Company's filing and does not implement new rates as anticipated by the Act?**

A. No. Clearly, Section 24 of the Act did not contemplate "doing nothing." If the legislature had believed that the current rate structure assured that costs would continue to be recovered fairly across all rate classes in light of net metering and the growing DG energy sector, such that both DG and non-DG customers were contributing appropriately toward the costs of the distribution system on which they rely, then Section 24 has no purpose. The PUC should conclude that Section 24 has a clear purpose and implement a revised rate structure to re-calibrate the cost contributions of DG customers in some fashion to more fairly and equitably balance the contribution to the costs of operating, maintaining, and investing in the distribution system by DG and non-DG customers alike.

Intervenor Recommendations for a Broad Stakeholder Process

**Q. Several intervenors conclude that Section 24 should be implemented in the context of a larger stakeholder process to develop not only a rate proposal, but a proposal to modernize the distribution system as well (Gold Direct Testimony at Page 7, Besser Direct Testimony at Page 17, Parker Direct Testimony at Bates Page 26, Anthony Direct Testimony at Bates Page 15). Do you believe that this interpretation is consistent with the requirements of the legislation?**

A. No. If the legislature had intended for a lengthy stakeholder process to discuss the development of a revenue neutral rate proposal as well as a proposal to modernize the distribution system, then they would have either required it or established an appropriate timetable for the Company to file and the PUC to review such proposals, commensurate with such a process. However, the legislature established a specific and relatively short timeframe for the implementation of new rates in this proceeding that was less than one year from the opening of the docket. Based on this timetable and the broad scope of issues related to a proposal to modernize the Rhode Island distribution system, the Company concludes that the legislature did not intend for the Company's rate redesign proposal to be developed and/or reviewed in the context of discussions regarding topics pertaining to modernizing the distribution system.

**Q. Was it the intent of the parties to this proceeding to establish a stakeholder process to consider system modernization rather than implement new rates at the conclusion of this proceeding?**

A. No. As noted in the June 2, 2015 meeting summary memorandum issued by Commission Counsel Cynthia Wilson-Frias on June 3, 2015 in Docket No. 4545:

> Since the May 14, 2015 presentations in this docket, New England Clean Energy Council (NECEC), Conservation Law Foundation (CLF), Acadia Center, and National Grid met to discuss the scope of the upcoming rate design docket. The discussions were deemed positive.
>
> Abigail Anthony noted that the statute requiring the rate design review is fairly narrow. This was echoed by Charity Pennock and Jerry Elmer. This is not a grid modernization in the sense of the upcoming Massachusetts filings to be made by National Grid. It was characterized as a "first step" toward something more in the future.[6]

That being said, the Act does not preclude the Company or the PUC from investigating topics relating to modernizing the distribution system, either generally or in other proceedings. Nor does it preclude investigation of advanced metering applications or more sophisticated rate design proposals outside of this docket.

However, as the Company has noted in its testimony, implementation of grid

[6] Memorandum to Stakeholders in Docket No. 4545, dated June 3, 2015, at 1.

modernization, advanced metering infrastructure, and associated sophisticated rate design changes will require significant investment for which the Company would seek cost recovery and, therefore, would not constitute a revenue neutral rate redesign. Any benefits to customers by investing in the distribution system to improve system efficiency or to implement advanced metering infrastructure must be carefully weighed against the costs of such investments. In this regard, the PUC and other Rhode Island stakeholders will be able to leverage the information obtained through various pilot programs currently underway in Rhode Island and Massachusetts, as discussed in the Company's pre-filed direct testimony and in response to discovery in this docket.[7] The information obtained from thousands of Smart Grid pricing participants in the Smart Energy Solutions Program in Worcester, Massachusetts, currently being operated by the Company's affiliate, Massachusetts Electric Company, as well as the participants in the Company's Tiverton/Little Compton, Rhode Island pilot can provide valuable information regarding customers' (i) willingness to participate in demand response events or to accept time-varying rates, (ii) efforts to actively manage their consumption in response to price signals, and (iii) success in controlling their usage and contributing to reductions in peak demand on the system.

[7] Zschokke and Lloyd Direct Testimony at Bates Pages 39-40, Responses to Data Requests Division 1-4, Division 1-6, and Division 1-19.

Intervenor Opposition to Alleviating Cross Subsidization of DG Customers by Non-DG Customers at This Time

**Q. Intervenor testimony states that potential cross-subsidization of DG customers by non-DG customers is not significant and there is no sense of urgency with regard to implementing rates in this proceeding (Besser Direct Testimony at Page 13, Gold Direct Testimony at Page 3, Anthony Direct Testimony at Bates Page 11, Golin Direct Testimony at Page 25). Please comment.**

A. The Act establishes a clear and specific timeframe for the implementation of new rates. The intervenors' belief that there is no urgency runs counter to the statutory requirement. By including Section 24 in the Act, the legislature has expressed its intent for the PUC to implement new rates in early 2016 that are fair to all customers. Also, in its pre-filed direct testimony, the Company provided evidence that a strong program to promote renewable DG by a state or country will result in a swift acceleration in use of distributed renewable generation, which would be viewed as a success. Implementing appropriate rates now will prevent further unjust cross-subsidies from occurring in Rhode Island with the anticipated success of the RE Growth Program, as has occurred for the customers of the Company's Massachusetts affiliate within the last five years. The interveners are correct to note that the Company will be kept whole; however, it is the non-participating customers who will be harmed by this unfair treatment if the PUC does not approve rates that reflect a more equitable level of cost responsibility.

**Q. How much does a typical residential customer currently pay for the support of initiatives that are not related to the provision of electric delivery and commodity service?**

A. Schedule NG-1-R shows the detail of the electric bill for a 500 kWh residential customer receiving delivery service on Rate A-16. As shown on this schedule, this customer currently pays in excess of $10.00 per month for costs related to the support of renewable energy, energy efficiency, and subsidies to other rate classes. Several of the intervenors claim that the additional cross-subsidization of DG customers that will occur as a result of the implementation of the RE Growth Program is insignificant. However, that subsidy must be viewed in light of the current contributions that customers are already making to fund the facilitation of the development of renewable energy and other initiatives designed to further state policy goals.

**Q. There are existing subsidies by certain rate classes for the benefit of other rate classes. For example, as shown on Schedule NG-1-R, residential customers pay approximately $2.40 per month in subsidies to Rate G-62, the outdoor lighting class, and low income customers. Why is this subsidy appropriate?**

A. Subsidies to certain rate classes are sometimes necessary to alleviate bill impacts that may be considered undesirable. The subsidies approved in the Company's last rate case (Docket No. 4323) were determined in that particular proceeding to be appropriate. The

PUC determined that the benefit to customers in the rate class receiving the subsidy outweighed the cost to customers in the rate class providing the subsidy.

The Company, and ultimately, the PUC recognize that temporary or permanent subsidies to certain customers may be appropriate to achieve desired goals. In this proceeding, the Company has not proposed to eliminate the subsidies that are provided to DG customers by non-DG customers. The Company's goal in this proceeding is to propose rates that fairly allocate the cost of the distribution system to all users of that system. A fair rate structure will reduce the existence of any subsidies that currently result from the present rate design. Taking into account the legislative purposes of the Act and the legislative intent of Section 24, the Company's rate design proposal strikes a balance between fairness and equity for all customers while achieving one desired goal of the Act through the Company's RE Growth Program, which is the facilitation and promotion of DG.

**Q. OER states it is premature to redesign rates now because, once the distribution system is modernized, rates will have to be redesigned again (Gold Direct Testimony at Page 6). Please comment.**

A. This statement by Commissioner Gold implies that rate changes driven by efforts to modernize the distribution system are imminent. Although the Company agrees with other stakeholders that there is value in modernizing the grid, the discussion of grid modernization is just beginning in Rhode Island. A period of time is necessary to discuss the nature and extent of grid modernization efforts that would be beneficial for customers and the PUC would need to convene proceedings to determine, if the cost for grid modernization provides adequate benefits to customers to approve of any effort to move forward.[8] The Company would begin its implementation effort when any such proposal is approved in Rhode Island.

The Company does not believe that implementation of rate design changes every five to 10 years is unnecessary or wasteful if the changes are necessary or desirable to correct inequities present in the then-current rate design. Indeed, the perspective that a change in rate design is wasteful in this context ignores the current bill impacts to the vast majority of customers in Rhode Island who are non-DG customers and currently are paying for distribution system investments that DG customers are not paying for, yet the DG customers enjoy the benefits those investments provide.

Again, the Company believes that the intent of Section 24 was not to review rate design in the context of modernizing the distribution system, or to delay rate changes until some unspecified future date, but rather, to address inequities present in the current rate structure created from the proliferation of DG and to address those inequities within the

[8] In Massachusetts, the Company's affiliates have a grid modernization proposal pending before the Massachusetts Department of Public Utilities (Department) which has taken several years to develop through a collaborative process. See Petition of Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid for Approval of its Grid Modernization Plan, D.P.U. 15-120.

timeframe specified in the Act. The Company's proposal is intended to consider one of John C. Bonbright's long standing principles on rate design: the stability of rates themselves and the gradual change in those rates as a means of avoiding serious adverse impacts to customers.

**Q. Do you agree with the recommendation that the proposed rate design changes should be considered as part of a general rate case (Golin Direct Testimony at Page 31, Chriss Testimony at Page 15). Do you agree?**

A. No. Section 24 of the Act mandates that the PUC consider a revenue neutral rate design proceeding outside of a general rate case. This requirement allows the PUC to solely consider fair and appropriate rate structures without the added complications introduced by changes in the Company's overall revenue level. Section 24 also expressly authorizes the Company to base its revenue-neutral rate design proposal on the allocated cost of service study (ACOSS) filed with its compliance filing in its last rate case. For all intents and purposes, the current proceeding accomplishes the same end result as a general rate case at much less cost to customers. The evidence includes an approved ACOSS and intervenors that represent the majority of the affected customers. The only thing missing is a change in the overall revenue requirement, which would affect the Company's level of revenue earned and the resulting overall bill impacts, but would not have any effect on the allocation of costs to rate classes or the ultimate design of distribution rates.

**Q. Some intervenors claim that the Company has not performed a proper analysis of demand patterns to substantiate their proposed charges and there is no evidence that non-DG customers subsidize DG customers (Golin Direct Testimony at Page 23-24, Anthony Testimony at Bates Page 11). Do you agree?**

A. No. Generally speaking, it is not possible to identify the cost to serve any specific customer or class of customers with complete accuracy. Although the Company can readily identify and quantify certain costs to interconnect individual customers to the Company's distribution system, such as the cost of a meter and service drop, it is difficult to attribute the cost of the integrated distribution system (i.e., the poles, towers, substations, conductors, etc.) to individual customers or classes of customers with the same level of precision. It is for this reason that ACOSS methodologies have been developed and accepted by regulatory commissions that attempt to assign cost responsibility to rate classes (i.e., groups of customers with similar characteristics) based upon cost causation. We know that individual customers impose different costs on the system. For example, a customer who is located next to a substation costs less to serve than a customer who is located many miles from the same substation. It has been long recognized that attempting to identify and quantify the incremental cost imposed by a customer on the distribution system is a difficult and burdensome task, and likely would result in confusion and dissatisfaction among customers. Therefore, it is an accepted standard of ratemaking within the utility industry that rates designed for a particular rate class reflect the average cost to serve that class as determined in an ACOSS. In designing rates based on the average cost to serve, we accept the fact that some customers within the rate class will pay rates that are higher than their cost to serve and some will pay lower rates. This “intra-class” subsidization is necessary to simplify the cost allocation and rate design process. Rate design can, to some extent, minimize the intra-class subsidies with charges that reflect the same cost causation principles that are used to allocate costs.

In the Company’s direct testimony, the Company documented that DG customers need the distribution system and derive significant value and benefit from its existence. Fairness and cost allocation principles dictate that appropriate contributions to the costs of the distribution system are required by customers with DG. Also, the complexity created by generation being provided locally was described in the Company’s direct testimony. Additional investment by the Company will be needed to manage this complexity of load flow. This investment is not necessary to serve the traditional load customers without DG, and the non-DG customer should not have to shoulder all the new costs associated with the promotion of DG because it would be unfair, inequitable, and against industry-standard cost allocation principles.

**Q. Is it necessary to treat DG customers as a separate class in an ACOSS?**

A. No, not at this time. The Company has traditionally included both partial requirements customers and full-requirements customers in the same ACOSS classes. As discussed elsewhere in the testimony, there is no evidence that a customer who uses the integrated distribution system for back-up and supplemental service costs less to serve than does a full-requirements customer since partial requirements customers utilize the distribution system during the period of time when their DG unit is not operating. In fact, as described above, the presence of DG on the system causes incremental operating costs to the system in the form of real-time voltage control, management of intermittency of generation, potential for investment in more feeders to meet the needs of DG customers, replacement of current facilities paid for by interconnecting DG after failure, property taxes, and customer service and administrative costs. Therefore, it is important that DG customers pay charges that fairly reflect the costs that are allocated to their respective class of service.

**Q. To the extent that installation of DG and energy efficiency contribute to avoided system costs, how will such future avoided system costs be reflected in rates?**

A. As an initial point, it is important to note that energy efficiency is different from DG. Implementation of an energy efficiency measure changes the demand profile of a customer. Installation of a DG facility does not affect customer usage but only changes the location of the generation. Thus, installation of DG may even contribute to greater levels of customer usage because the cost to increase use is nominal to the DG customer. In addition, as discussed in more detail later in the testimony, the ability of a DG customer to contribute to a permanent load reduction is limited because it depends upon a number of factors, such as the customer's load profile and the coincidence of the generation with the customer's use, the type of and installation of the DG facility, the ongoing operation of the facility as well as the capacity of the feeder to which the customer is connected.

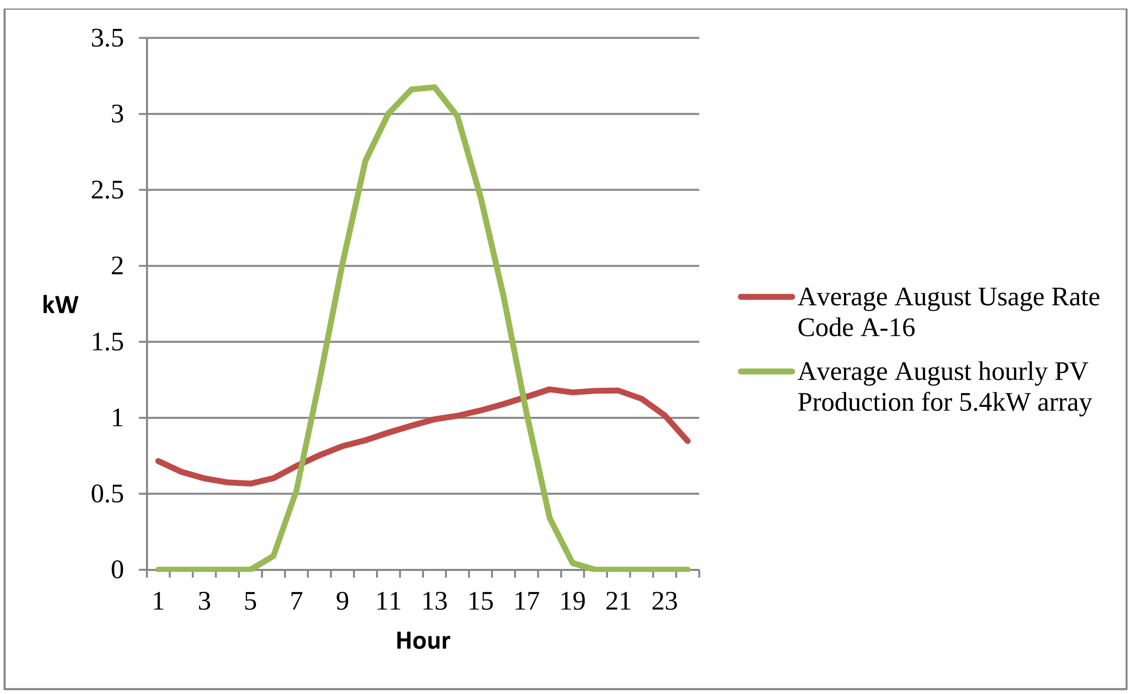
To the extent that any customer, for any reason, permanently reduces their demand, this load reduction will be reflected in observed levels of demand on individual feeders over time if the demand reduction occurred during the peak period. The reductions in permanent load may reduce the need for increased capacity on individual feeders and substations, and thus, result in avoided distribution system costs over time. The avoided system costs will be reflected in the form of a lower overall Company revenue requirement than would otherwise have resulted absent the load reductions and consequently a lower allocation of costs to the rate classes in the ACOSS, which inherently include the customer who reduced load.

Therefore, all customers share in this benefit through the cost of service and ACOSS process over time. The sharing of this benefit is appropriate, in fact, it is crucial to ensuring that non-DG customers will receive a benefit in the form of lower rates in exchange for the support that they provide today through current renewable energy cost recovery mechanisms. The compensation of certain customer actions, such as installation of energy efficiency or DG, by all customers has an underlying assumption that those non-participating customers who provide that compensation will receive benefits in the future equal to, or greater than, the compensation that they provide through current rates.

**Q. Doesn't the installation of customer-sited DG reduce a customer's need for distribution system capacity and, therefore, potentially reduce the need for future system investment?**

A. A DG facility reduces a customer's need for system capacity during the hours that the DG facility is operating, but very few renewable energy generation units are able to operate continuously 24 hours a day. Table 1 below is a graph illustrating the load profile for a residential customer on a peak day in August. This data is based on the Company's load research data for the residential class and represents the average load profile of a Rhode Island residential customer. As indicated on this graph, the customer's peak demand occurs at 6 p.m. Overlaid on this graph is a representation of the hourly output of a typical 5 kW solar unit for August. As shown by the intersection of the two profiles, the output of the solar unit reduces the peak demand of the customer by approximately 30 percent. However, the customer's demand at 8 p.m., when the output of the solar unit is 0, is 1.2 kW which is only 1 percent less than the customer's maximum demand at 6 p.m. Therefore, overall, the solar unit will only be able to reduce the customer's peak demand by 1 percent. In addition, this analysis assumes that the customer's DG facility will always be available on peak days. However, the Company cannot depend on the availability of customer-sited generation. DG facilities are subject to unexpected failure and/or routine maintenance, both of which are out of the Company's control. Therefore, it is necessary for the Company to maintain additional available distribution system capacity to meet the load requirements of DG customers whose facilities may be inoperable. In addition, the potential to defer or avoid future system costs is greater in those areas that are currently constrained, or will be constrained in the near future. But the success of DG sited in these areas will be dependent upon local load growth as well as the amount of DG that can be sited in these constrained areas. In areas that currently have considerable excess capacity, or are experiencing little or no load growth, the potential to defer or avoid the cost of future investment is very low.

**Table 1 - Residential A-16 Customer Hourly Usage vs. Hourly PV Production**



Intervenor Conclusions Regarding the Costs and Benefits of Distribution Generation

**Q. Several intervenors claim that the potential benefits of DG have not been adequately analyzed and compared to the costs of the Company's proposal (Gold Direct Testimony at Pages 4-6, Anthony Direct Testimony at Bates Page 11, Besser Direct Testimony at Bates Pages 5, 12, 13, Parker Direct Testimony at Bates Page 27). Do you agree?**

A. No. A comprehensive discussion of the potential benefits of DG is included the Company's direct testimony filed in this docket.[9] In addition, the Company provided other sources of information on the potential benefits of DG in response to discovery questions. Regardless, the potential benefits of DG do not affect the Company's proposed rate designs in this docket. As the Company has indicated repeatedly, the benefits of DG should be reflected in the compensation provided to customers that own, or directly benefit from, DG facilities and not in the design of distribution rates. Distribution rates should be designed to recover the cost of the distribution system in a fair and equitable manner from all customers who rely on the system.

**Q. Have the intervenors to this proceeding provided any information for the PUC's consideration regarding the benefits of DG?**

[9] Electric Power Research Institute. The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources (February 2014), (the EPRI Paper), a copy of which was provided as Schedule NG-3, at Bates Page 79.

A. Only one intervenor, Acadia Center, has provided any specific information regarding the benefits of DG.[10] In their analysis, they attribute between $0.005 per kWh and $0.025 per kWh as the value of solar to the distribution and transmission systems and a contribution at peak of only 25 - 30 percent, which is less than an ISO-NE led DG forecasting working group had determined in 2014. Since the distribution and transmission rates that provide value to a net metered customer in the form of displaced energy and a net metering credit on Rate C-06 are approximately $0.06 per kWh, it is clear that net metered customers are being overcompensated for the value they provide the distribution and transmission systems, based on the Acadia Center study.

**Q. Who are the recipients of the potential benefits associated with DG?**

A. Potential benefits of DG can accrue to two groups: the DG customer[11] and all others. The owner or developer of DG clearly benefit through the receipt of compensation generated through the construction and operation of the DG facility. In order for a customer to install DG, the benefit provided must be greater than the cost to install, own, and maintain a DG facility by an amount that is sufficient to allow the customer to earn an

[10] http://acadiacenter.org/wp-content/uploads/2015/04/AcadiaCenter_GridVOS_Massachusetts_FINAL_2015_0414.pdf; http://acadiacenter.org/document/value-of-distributed-generation-solar-pv-in-ri/

[11] For ease of reference, the Company is generally using the term "customer" as the recipient of compensation as a result of the construction and operation of a DG facility. However, compensation provided throughout the life cycle of a DG facility can be received by a developer, owner, or a customer.

appropriate return on investment; otherwise, the customer will not make the investment in DG.

The second group, collectively referred to as "all others," is comprised of the utility, all other customers, and society generally. The potential benefits provided to all others typically are not immediate and are difficult to identify and quantify. Benefits have been difficult to monetize because the value cannot be accurately determined without significant investments in measuring, at a very granular level, operational attributes of the distribution system and the same data from DG facilities. Advanced grid technologies and contractual control of DG is necessary for this monetization to occur. At this stage of development, the DG industry has potential benefits to the utility and others, but those benefits may not be realized for years to come. Currently, the DG industry provides little to no actual and quantifiable benefits to the utility and other customers.

**Q. Please describe in more detail the benefits and services that are provided to DG customers.**

A. Most of the benefits provided to DG customers are available immediately upon operation of the facility and may include reduced electric bills, increased on-site reliability, increased property values, and improved productivity. The distribution company also provides benefits to DG customers. These benefits were discussed in the Company's pre-filed direct testimony[12] and include i) access to the distribution system to enable power to be imported to the customer's facility for on-site use and to be exported to be transmitted to the market, ii) reliability, iii) voltage quality, iv) start-up power, and v) efficiency. These or similar services are, in fact, provided to all customers, both those with DG and those without DG. The Company continues to provide these types of services to customers who install DG, generally at the same level as before the installation of the DG facility, and in many case, at a higher level.

**Q. Please explain how the distribution company may provide a higher level of service to customers with DG facilities following installation of the DG facility.**

A. Due to the physics of electricity, any motor load (air conditioning, refrigeration compressors, water pumps, etc.) typically requires five to seven times its power rating upon start-up (also known as its inrush power requirement). Without the distribution system providing this inrush power requirement, inverter-based DG (solar and wind) facilities would trip off-line due to voltage collapse because an inverter-based DG facility simply cannot provide the level of inrush power needed for start-up. DG customers who install only enough solar to meet monthly electric usage cannot provide the required inrush power without a connection to the distribution system or having an on-site energy supply (typically battery storage). However, installing an on-site energy supply can

[12] Zschokke and Lloyd Direct Testimony at Bates Pages 17-18.

easily double the installation costs of a DG project and, as a result, very few customers actually install these on-site sources. In short, all customers with DG that have no other on-site source require a connection to the distribution system to obtain that energy, or inrush power, and such customers must therefore pay their fair share of system costs.

**Q. What are the benefits that can potentially be provided to the Company and to other non-DG customers through the installation of DG?**

A. As discussed in the EPRI Paper included as Schedule NG-3 to the Company's pre-filed direct testimony (Bates Page 79), and the other industry publications provided referred to in Schedule NG-2-R, the potential benefits of DG to the Company that eventually could be enjoyed by non-DG customers include: i) avoided generation energy and capacity costs; ii) avoided transmission and distribution costs; and iii) reduction in line losses. Societal benefits for non-DG customers include i) environmental improvements such as improved air quality; ii) reduced reliance on fossil fuels for wholesale electricity generation; and ii) economic development opportunities.

**Q. Has the Company considered the potential benefits to the distribution system of DG in developing its proposals in this proceeding?**

A. Yes. The Company has considered the potential benefits to its distribution system provided by DG and has concluded the following:

- At this time, the potential benefits provided to the distribution system by customer-sited intermittent (solar, wind) DG are minimal, for a number of reasons:
    - The current low levels of penetration are spread sporadically throughout the distribution system.
    - In all cases, peak loads on distribution feeders do not occur at the same or near the times as the peak output of intermittent DG. Feeder peaks for the summer months, which are the highest peaks experienced during the year, are typically between 3 p.m. and 9 p.m. Solar DG peaks at 12:30 p.m. during the summer, and wind DG peaks during the early morning hours in the winter.
    - The intermittent nature of some DG (solar, wind) does not provide sustained production during various weather related events (i.e., cloud cover, high wind conditions, etc.).
    - In all cases of which the Company is aware, the DG customer relies on the distribution system for backup power needs in the event the system is not available (cloud cover, overnight, high-wind events that trip a wind turbine off-line, maintenance concerns, unexpected mechanical failure, etc.).
- For non-intermittent DG (anaerobic digestion, natural gas-fired combined heat and power ) that has a controllable fuel source, without contractual arrangements with a willing customer, the Company cannot rely on this type of DG for a number of reasons:

- The DG customer has to be willing to contract with the Company that commits the DG facility to operate at certain levels over a period of time.
- The DG customer will typically arbitrage the operating costs (fuel, on-going maintenance, etc.) to then-current electric rates to serve their own needs in a way that results in the lowest cost of energy without the Company's knowledge.
- In all cases of which the Company is aware, the DG customer relies on the distribution system for back-up power needs in the event the system is not available (fuel source disruption, maintenance concerns, unexpected mechanical failure, etc.).

Even without a specific contract with the customer, until the DG facility's operation can be seen to show sustained peak load relief on a feeder, the Company must assume it is not available and therefore must continue to provide safe and reliable service to all neighboring customers where the DG facility is located.

**Q. How did the Company analyze the potential benefits of DG to develop its proposal in this proceeding?**

A. The Company relied on the wealth of industry information that currently exists as a guide to its analysis of the potential benefits of DG in addition to its own experience in implementing DG on the National Grid's distribution systems. Several articles noted in the Company's response to Data Request WED 1-13 in particular have provided insight into the costs and benefits of DG. The Company is providing its response to this information request as Schedule NG-2-R as a reference. Based on its analysis, the Company believes that its proposals in this proceeding are fair and equitable to all customers, including customers with and without DG.

As discussed earlier, the Company has a number of pilots in Rhode Island and Massachusetts looking to quantify the value of customer-side resources (energy efficiency, demand response, and DG). These are the Smart Energy Solutions Program in Worcester, Massachusetts, the Tiverton/Little Compton pilot in Rhode Island, and the Solar Phase II program in Massachusetts. The goal of Solar Phase II is to better understand the potential value solar provides to the distribution system. This project is well underway with preliminary results expected to be available in late 2016. Once the various programs and pilots described above have concluded and the results have been fully evaluated, the Company may consider additional compensation for DG customers who install facilities in targeted locations. This compensation could be in the form of zonal credits as provided in the RE Growth Program tariffs, among other ways to incent the installation of DG in specific locations.

**Q. Are there any general observations resulting from an evaluation of the various industry publications referred to in Schedule NG-2-R?**

A. Most of the studies cited in the publications admit to the difficulty in valuing the benefits of DG, although many of the available DG studies appear to reach similar conclusions with regard to certain factors, such as:

- The costs and potential benefits of DG vary by utility and geographic location;
- The potential benefits provided by DG vary by technology. For example, combined heat and power generation may be more reliable for providing load reduction than renewable energy generation. However, more significant environmental benefits may be provided by renewable forms of generation;
- Standard methods of evaluation are required to ensure consistent evaluation of potential benefits; and
- There is a need for contractual arrangements between the DG facility and the utility for DG to deliver utility-side potential benefits so the utility does not then have to procure additional supply, additional transmission and distribution line capacity, and associated penalties for non-compliance (similar to the requirements of the ISO-NE's forward capacity market).

The costs of implementing DG must also be considered to determine its true value (i.e., the benefits minus the costs). In some cases, the net value of DG can be negative, where the costs exceed the benefits. Regardless, most studies, even those in support of aggressive implementation of DG, cite the cross-subsidization by non-DG customers as an important issue that needs to be addressed by utility companies and regulators.

**Q. Does the Company believe that a complete evaluation of the benefits of DG is necessary or relevant to implementing rates in this proceeding?**

A. No. Although the quantifiable benefits provided by DG are relevant to the amount of compensation for DG output, that topic is currently mandated by various statutes and is beyond the scope of this proceeding. The Company's retail rates are functionally unbundled, with the cost and pricing of commodity and transmission services determined separately from those of distribution service. The rate changes proposed in this proceeding are limited to base distribution rates only. As a result, only the potential costs and benefits affecting the distribution system are relevant to the proposals in this docket.

**Q. Please discuss the potential benefits to the distribution system in more detail.**

A. The potential benefits to the distribution system that could be provided by renewable energy generation include: i) delay of infrastructure investment; ii) reduction in line losses; iii) extended service life of distribution system equipment; and iv) providing voltage support services. We discuss these in more detail below.

<u>Delay of Infrastructure Investment</u>

To the extent that distributed energy resources (DG, or any other customer-side resource like energy efficiency, active load management, or demand response, also known as distributed energy resources) can permanently reduce peak demand on individual feeders and substations, they can potentially decrease the capacity required to serve load and defer capital investment and improvements at the feeder and substation level. However, as indicated in the EPRI Paper: "For either delivery or supply capacity, the extent to which [distributed energy resources] can be relied upon to provide capacity service and reduce the need for new [transmission and distribution] and central generation infrastructure depends on planners' confidence that the resource will be available when needed across the planning horizon."[13] There are two specific circumstances under which the potential to delay system investment can be maximized. The first is using DG to reduce peak load on specific feeders and substations that are overloaded, and will require updates in the near future. The second is using utility-controlled DG, as opposed to customer-sited DG, to ensure a greater level of reliability and coordination with utility system operation.[14]

<u>Reduction in Line Losses</u>

Having a local supply of power reduces the distance power has to flow from bulk

[13] Schedule NG-3, at Bates Page 105.
[14] Schedule NG-3, at Bates Page 107.

generating facilities to customer loads. As power flows, there are inherent losses during the process. The average line loss in the New England area is approximately 7 percent. Locally-sited DG will reduce overall line losses if it is located in an area with enough load density. In remote load centers, this does not occur, and in fact, the generation itself produces line losses until it gets to a load center. The issue is accurately measuring this "value." Until every load and generation point on the system has interval metering (metering that can record power consumed to as small an interval as one minute), line losses can only be estimated. Because losses are determined by the amount of power flowing, and the amount of power generated by DG pales in comparison to the total power flows in the state, the decrease in line losses from DG are de-minimis.

Extended Service Life of Distribution System Equipment

By reducing the amount of time distribution system equipment is operating at or near its operational capacity limits and, therefore, creating heat in the process, its expected life could be extended. However, as with the discussion above on line losses, and the fact that solar and wind do not provide significant peak load reductions, DG, in general, has a de-minimis impact on extending the life of electrical equipment.

Providing Voltage Support Services

Most intermittent DG uses an inverter-based system to manage power production and export power onto the distribution system. A fundamental issue is that any generation, when it is operating, raises system voltages since it is a new power source on the system. Controlling voltage on the system is critical to prevent a failure of customers' electric equipment. The distribution system currently provides voltage support through a series of tap changing transformers, line regulators, and capacitor banks. These pieces of equipment make fairly large changes in voltage when activated, and in some cases, smaller increments of control are necessary. Inverters can be programmed to provide voltage support services by injecting or absorbing volt-ampere reactive, or VARs. The Company's Massachusetts affiliates are conducting just this sort of research and development through its Solar Phase II program to determine how and where solar DG could be deployed, and importantly, the potential value of providing this service to the system.

**Q. Has the Company reviewed studies conducted by other utilities related to the potential benefits provided by DG to the distribution system?**

A. Yes. The Company cites below several studies, and the conclusions reached regarding the potential ability of DG to delay capital investment.

<u>Arizona</u>

A study conducted in 2009 by R.W. Beck for Arizona Public Service[15] concluded the following:

[15] http://files.meetup.com/1073632/RW-Beck-Report.pdf

> "Distribution capacity is solely based on local peak loads and therefore distribution capacity savings can only be realized if distributed solar system are installed at adequate penetration levels and located on specific feeders to relieve congestion or delay specific projects." Section 3.8 of Beck Study.

A 2013 updated study[16] further concluded that, due to the low capital expenditure required for feeder upgrades, there are an insufficient number of feeders that can defer capacity upgrades based on non-targeted DG installation to determine measurable capacity savings. Therefore, the conclusions from the 2009 study were confirmed, specifically, that no capacity savings existed from installation of solar resources on the distribution system without specifically targeting the locations of solar resource.

<u>Maine</u>

A Maine Public Utility Commission Value of Solar study estimated the total potential value of solar to be $0.182 per kWh. However, a value associated with avoided distribution investment was not included in the study because forecasted peak loads in Maine are generally flat, so capacity-related distribution investments are not anticipated. Therefore, this potential benefit is not included in the study, and is left as a placeholder for future studies if applicable.

[16] https://www.azenergyfuture.com/getmedia/77708c68-7ca6-45c1-a46f-84382531bae3/2013_updated_solar_pv_value_report.pdf/?ext=.pdf

Rhode Island (Acadia Study)

The Value of DG, Solar PV in Rhode Island, July 2015, included as Exhibit No. AC-5 (Bates Page 12) to the pre-filed direct testimony on the Access Fee of Abigail Anthony, Phd, places the value of avoided distribution system costs at between $0.0047 per kWh and $0.0277 per kWh depending upon orientation of the solar panel.

**Q. Please discuss the costs of implementing DG.**

A. The costs of implementing DG include the following:

i) Program administration costs including incentives paid to program participants and lost revenue resulting from reduced kWh deliveries to participants;

ii) On-going operation and maintenance costs and increased property taxes resulting from customer-funded upgrades needed for DG interconnection not paid for directly through participant interconnection costs and fees;

iii) Utility administrative costs including system design and planning to account for proposed and actual DG projects; and

iv) On-going operation and maintenance costs (many of which are identical to non-DG customers) such as, but not limited to:

a) Billing and metering issues that arise;

b) Investigation of reliability issues; and

c) Storm damage repair of utility-owned equipment needed for interconnection.

**Q. Please discuss the administrative cost of implementing DG in more detail.**

A. In addition to the above, DG projects cause the Company to incur other costs, such as:

i) For public entity virtual net metered projects, the Company is required to perform significant work to set up a virtual net metered project, manage the required monthly allocation of credits from the DG host site, and respond to the many customer questions about this process;

ii) The Company responds to customer requests for information on the interconnection process as well as the various programs that incent DG; and

iii) The Company is required to reconcile the cost of interconnection for all projects.

<u>Intervenor Allegations Regarding Complexity of Proposed Rate Design</u>

**Q. The Division (Pereira Direct Testimony at Bates Page 10) and several other intervenors state in their direct testimony that the proposed tiered customer charge would cause customer confusion and would be too costly to implement (Anthony Direct Testimony at Bates Page 10-11, Besser Direct Testimony at Bates Pages 12, 18, Golin Direct Testimony at Bates Page 28, Parker Testimony at Bates Pages 11, 13). Please comment.**

A. The proposed rate structure is not significantly different than the current structure. Currently, customers are billed a single customer charge and a per kWh distribution charge each month. This will also be the case with the proposed rate structure. Customers already understand the concept of a monthly customer charge. For customers to understand the change in the structure of the customer charge, it will be necessary for the Company to communicate two concepts: i) how the customer charges will be determined under the tiered structure; and ii) why the new structure is appropriate. In addition, the Company would include references to the customer's bill which includes information regarding customer electric usage history for the past 13 months, plus an explanation of the potential bill impacts resulting from the new rate design. Also included will be an explanation of the transition to the new customer charge.

Many of the intervenors are advocating for time-varying rates, smart demand charges that might vary by location, and other more complex rate designs (Anthony Direct Testimony at Bates Page 7, Besser Direct Testimony at Bates Page 9, Golin Direct Testimony at Bates Page 30, Parker Direct Testimony at Bates Page 21). If simplicity and understandability are the primary considerations in the adoption of new rate structures, then these suggestions will not progress very far, as they are significantly more complicated and therefore more difficult for the average customer to understand. Also, they would require additional significant investment in advanced metering infrastructure and systems to implement. Notably, none of the intervenors in their testimonies seem to believe that the complexity of the rate designs concepts they advocated should be a barrier to adoption.

**Q. Please explain how the Company would communicate rate changes to customers.**

A. The Company already conducts significant outreach to customers on a variety of different subjects, such as energy efficiency, storm readiness, rates, and tariff descriptions. The forms of these communications include bill messages, monthly bill inserts, website postings, and special mailings, such as OPower Home Energy Reports provided through the energy efficiency programs. Any outreach program to customers regarding a change in rate structure and design would first leverage these existing communication channels in order to reach customers through media with which they are already familiar. Using existing communication methods will also ensure that the cost of additional outreach and education is minimized.

**Q. Acadia Center criticizes the Company's proposal because the Company has not proposed tools to help customers manage their bills. Please comment.**

A. The Company already has tools in place to help customers manage their bills. In addition to website postings that explain details about rates and billing, the Company communicates information to customers regularly regarding ways to reduce consumption. As indicated above, the Company will use existing methods of customer communication to incorporate information related to changes in rate structure and design, and the implication those changes may have on usage patterns specifically as another tool to garner more participation in the Company's energy efficiency programs.

The Company does not believe that it should be necessary to communicate to customers in real time when the customer may be approaching the threshold of the next tier and its higher customer charge. The Company already provides each customer with 13 months of usage history as part of the monthly bill presentation (See Exhibit NG-3-R). Based on their usage history, customers will be reasonably able to anticipate which months are likely to have the customer's maximum usage and will know that it will be necessary to be conscious of electricity usage throughout the month and not just when they are approaching a tier threshold.

**Q. EERMC claims that there is a large risk that customer bills could suddenly increase, which would cause customer confusion. Please comment.**

A. A sudden increase in a customer's bill will only occur if the customer has a sudden increase in their electricity usage in a particular month as compared to their 12-month maximum use, and that increase in usage pushes the customer into a tier with a higher customer charge. While this may happen during the first year of implementation as customers transition to the new structure and design, that aspect can easily be explained in the customer outreach efforts. Customers who increase electricity usage should expect their bills to increase no matter the rate design. An increase in usage that is significant enough to cause a customer to be assessed a higher customer charge commensurate with the tier's usage will increase a customer's monthly bill by less than $5.00 per month. While bill increases are not desirable generally, the increase in the customer's bill will communicate appropriately to the customer of the importance of being aware of and managing their electricity usage.

**Q. Has the Company estimated the cost to implement its rate structure and design proposals in its filing?**

A. The Company estimates that billing system modifications associated with the proposed rate design changes will cost approximately $25,000. As described earlier in the testimony, the Company plans to leverage existing customer communication media to communicate rate change information to customers and does not expect to incur significant customer outreach and education expense.

<u>Intervenor Advocacy for Time-of-Use Rates</u>

**Q. In their direct testimonies, the Division and other intervenors criticize the Company's proposal because the Company has not examined whether time-of-use rates would be a better proxy for demand and peak reduction (Pereira Direct Testimony at Bates Page 18, Anthony Direct Testimony at Bates Page 7, Besser Direct Testimony at Bates Page 9, Golin Direct Testimony at Bates Page 30). Can you please address these comments?**

A. As explained in the Company's response to Data Request Division 1-9, the Company does not believe that time-varying rates are superior to demand charges for recovery of distribution system costs. However, even if the Company was of the opinion that time-varying rates were a better option to its proposed tiered customer charge, the Company does not currently have the necessary metering installed on residential and small commercial customer premises and, therefore, it would not be possible to implement such a design within the timeframe required by the Act.

**Q. Does the Company see value in time-varying rates?**

A. Yes. The Company recognizes that time-varying rates may be an appropriate design for the recovery of commodity-related costs. In fact, as noted previously, the Company's Massachusetts affiliate is currently conducting its Smart Energy Solutions Program in Worcester, Massachusetts that incorporates time-varying rates for Basic Service, which is the equivalent service to Rhode Island's Standard Offer Service. The Company anticipates that the results of this pilot will greatly assist in the evaluation of the effectiveness of time-varying rates and their applicability to customers in National Grid's other service areas. However, as indicated repeatedly in the Company's testimony and in responses in discovery, the Company does not believe that time-varying rates are appropriate for the recovery of distribution system costs. The Company also notes that none of the intervenors have provided any evidence that time-varying rates are either appropriate for distribution system rates or are superior to the Company's proposed design. In addition, the Company cannot implement more complex rate designs without a significant capital investment in metering technology, which was initially agreed by all intervenors to be beyond the scope of this proceeding.

**Q. Several intervenors claim that the Company's proposed tiered customer charge structure would not encourage customers to consume less during peak demand period (Pereira Direct Testimony at Bates Page 11, Anthony Testimony Bates Page at 10, Besser Direct Testimony at Pages 6-8, Parker Direct Testimony at Bates Page 11). Please comment.**

A. Again, introducing a time element into the rate structure would require a significant investment in metering technology and the transition to a more complicated rate structure and design. The Company notes that the current residential and small commercial rate structures and designs do not include a time varying component. Thus, the Company's proposal to implement a tiered customer charge based on a customer's maximum monthly usage will encourage customers to use less energy at all times, but specifically during high use months. Because most customers tend to consume most of their monthly energy requirements during peak periods, any efforts by customers to reduce overall usage will most likely reduce peak use. The Company cannot implement a rate structure that incorporates a time element with existing metering equipment. As indicated in the Company's pre-filed direct testimony, the Company considers this proposal as a first step towards more equitable cost recovery and rate design. While the intervenors are attempting to present a concept that is reflective of a customer's size, as well as the demand that the customer has imposed on the distribution system, the concept is ill-timed and involves actions the Company must make that are outside of the scope of this proceeding. The Company's proposal reflects cost causation principles by designing rates that reflect customer size that can be implemented with existing metering equipment, and is less complicated for customers to understand as compared to the intervenors' suggestions.

**Q. Is there any guidance in the Act to support an increase to fixed charges as a means to ensure that DG customers pay their fair share of distribution system costs?**

A. Yes. In Section 25 of the Act,[17] the law mandates that the charge for the cost recovery of RE Growth Program costs be a fixed monthly charge per customer assessed to all distribution system customers, both those with and without DG. By mandating a non-bypassable per customer charge, the legislature has indicated its understanding that per kWh charges allow DG customers to avoid contribution toward certain types of costs and its desire that, in the case of RE Growth Program cost recovery, they cannot bypass their responsibility to pay for their share of these costs.

**Q. Will the proposed tiered customer charge impact low income customers (i.e., low income customers not currently receiving service on Low Income Rate A-60) (Anthony Direct Testimony at Bates Page 14)?**

A. Yes, but not necessarily negatively. Please see Schedule NG-4-R, which illustrates a customer with a usage profile that is representative of electric space heating use. This

[17] R.I. Gen. Laws § 39-26.6-25.

customer uses 500 kWh per month on average during the year, but uses between 600 and 750 kWh per month during December through March. As illustrated by this bill calculation, this customer would pay $1,188.36 per year under the current rate structure and $1,167.12 per year under the Company's proposed rate structure. Obviously, different usage assumptions could result in a customer paying higher annual charges under the Company's proposed rates; however, the Company has made every effort to ensure that customers will not experience significant (+/- five percent) bill impacts as a result of its tiered customer charge proposal and the generalization that the Company's proposed rates will negatively impact space heating, and lower income customers, is not accurate.

**Q. Will the proposed tiered customer charge discourage electric vehicles (Anthony Direct Testimony at Bates Page 15)?**

A. There is no evidence that the Company's proposal will discourage electric vehicles. Please see Schedule NG-5-R, which illustrates a customer that increases kWh consumption by 380 kWh per month in each month to supply power for charging an electric vehicle. A shown in this example, under existing rates, this customer would see an increase in total bill charges of $847.08 per year as a result of the increased annual consumption. Under the Company's proposed rates, the same customer would see an annual increase of $854.04. However, this customer's total annual bill charges would be $1,993.80, or approximately $12.48 per year less than annual charges of $2,006.28 under existing rates. Again, as in the previous example, different usage assumptions could result in a customer paying higher annual charges under the Company's proposed rates; however, the assumption that the Company's proposed rates will discourage customers from purchasing electric vehicles is unfounded.

**Q. OER Witness Gifford cites the possibility that increased fixed charges could have a positive effect on the Company's credit rating as happened for three investor owned utilities following a California Public Service Commission decision increasing fixed cost recovery for those utilities, and ultimately lead to a lower overall cost of capital. (Gifford Direct Testimony at Page 14). Please comment.**

A. Mr. Gifford actually implies that this might not be a good outcome as it could lead to higher returns for the Company that would not flow to customers prior to a rate case proceeding. Although factors affecting the Company's rate of return are not reflected, positively or negatively, in rate adjustments between rate cases, ultimately customers will receive the benefit of lower cost of capital and reduced revenue requirement following the Company's next general rate case. To imply that an outcome that will reduce costs for all customers is a bad thing is an illogical conclusion. In addition, Mr. Gifford opines that a decrease in the cost of capital would violate the revenue neutrality of the design. This is not the case. As indicated in the Company's pre-filed direct testimony on Bates Page 8, the proposed rates have been designed to recover the same revenue requirement that was approved in the Company's last general rate case. Many components that affect the Company's overall revenue requirement, such as inflation, property taxes, and various other factors that affect operation and maintenance expense change continuously, resulting in a change in the Company's earned rate of return, but not in the level of revenue billed to customers.

**Q. Does the Company have any recommendations to address intervenor concerns related to the tiered customer charge proposal?**

A. Although the Company believes that its proposed customer charge structure is appropriate, the PUC could consider alternatives to this proposal, such as a six-month ratchet as opposed to a 12-month ratchet. Alternatively, the PUC could approve no ratchet, that is, the customer's monthly charge would be based on the customer's usage during the billing month and could change month-to-month.

In addition, the PUC could direct the Company to delay implementation of the tiered customer charge for a period of time, which could be up to one year, in order to properly educate customers about the operation of the new rate structure and rates.

**Q. Does the Company have any comments regarding the Division's recommendation to move the customer charge for residential and small commercial customers to unit charges indicated in the Company's most recent ACOSS (Docket No. 4323) (Division Direct Testimony, Bates Pages 18-20)?**

A. The Division's recommendation, like the Company's proposal, results in a higher level of cost recovery through the fixed charge component. However, this recommendation will have more significant bill impacts on low use customers than would the Company's proposed tiered charges. However, if the PUC rejects the Company's tiered proposal, the Company believes the Division's recommendation should be approved.

## IV. Consolidation of Rates G-32 and G-62

**Q. Walmart recommends that the PUC reject the Company's proposal to consolidate Rates G-32 and G-62 and consider the consolidation in the context of a general rate case (Chriss Direct Testimony at Page 15). Please comment.**

A. The Company acknowledges that the proposal to consolidate Rates G-32 and G-62 is not necessary to accomplish the purposes of Section 24 of the Act, a point raised by several intervenors (Al-Jabir Direct Testimony at Page 2; Pereira Direct Testimony at Bates Page 23). However, it does address an issue related to fair and equitable cost recovery and, therefore, is consistent with that specific intent of Section 24. The ACOSS results in the last two general rate cases indicate that Rate G-62 customers are contributing rates of return that are far below the system average. In both cases, the Company determined that the revenue increases that would have been necessary to bring this class to full cost of service rates would result in excessive bill impacts for Rate G-62 customers. Therefore, this class is receiving a revenue subsidy from all other customers. This means that the smallest customers on the system are paying to support the very largest customers. As indicated in Schedule NG-1R, a 500 kWh residential customer pays $0.52 per month to subsidize the Navy and other large commercial and industrial customers on Rate G-62.

The Company is of the opinion that these two classes should ultimately be consolidated, whether consolidation occurs as part of this proceeding or as part of the next general rate case. The Company proposed the consolidation of Rates G-32 and G-62 at this time because the consolidation will have less impact on these customers' bills as part of a revenue neutral rate redesign than it would in a general rate case when the overall revenue requirement is also changing.

The Company has not proposed to eliminate the subsidy in this proceeding. Rather, with the proposed consolidation of Rates G-32 and G-62, the Company is providing the opportunity to eliminate the subsidy in the next rate case. The Company has no reason to expect that the ACOSS results in the next general rate case will produce significantly different results than the last two ACOSS. Therefore, it is probable that Rate G-62 as a stand-alone class will still require subsidization in the next rate case to minimize undesirable bill impacts.

## V. <u>Access Fee</u>

**Q. Can you please generally summarize the intervenors' claims regarding the Access Fee in this proceeding?**

A. Yes. The intervenors make a host of claims regarding the proposed Access Fee, which include, but are not limited to, the following:

(i) The Access Fee would have a negative effect on the renewable energy market in Rhode Island, foster uncertainty in the future, and have a detrimental effect on existing and future stand-alone DG projects (Gold Direct Testimony on Access Fee at Bates Page 3; Anthony Direct Testimony on Access Fee at Bates Pages 4-5);

(ii) The Company has not substantiated the costs that the Access Fee is intended to collect and the Company has not provided enough information to justify the magnitude of the Access Fee (Besser Direct Testimony on Access Fee at Page 8; Rabago Direct Testimony at Page 10; Anthony Direct Testimony on Access Fee at Bates Pages 6-7; Golin Direct Testimony at Page 9);

(iii) The Access Fee negatively impacts the ceiling prices of existing stand-alone DG projects and the financial health of current and future net metered customers (Carpenter Direct Testimony at Page 5);

(iv) The Access Fee is damaging to future RE Growth Program projects because it alters the pre-established prices provided by the tariff program (Carpenter Direct Testimony at Page 8);

(v) The Access Fee is designed to recover the Company's fixed costs in an out of date system, does not encourage investment in DG, and is inconsistent with the goals of the RE Growth Program and modernization of the distribution system generally. (Carpenter Direct Testimony at Pages 13-14; Rabago Direct Testimony at Pages 23-25; Anthony Direct Testimony on Access Fee at Bates 4-5; Golin Direct Testimony on Access Fee at Page 8);

(vi) The Access Fee is an improper fee for back-up services (Carpenter Direct Testimony at Page 8); and

(vii) The proposal to use the revenues generated by the Access Fee, which is a fixed fee, as a credit to the revenue decoupling mechanism (RDM), which is a variable per kWh charge, further shifts costs and revenues from a variable charge to a fixed charge, allowing the Company to make the RE Growth Program appear more expensive without an increase in revenues, which is inconsistent with the Act (Besser Direct Testimony on Access Fee at Bates Page 6).

Each of the claims is addressed below.

**Q. Please briefly explain the purpose of the Access Fee, and why it was proposed in this proceeding.**

A. As the Company stated in its pre-filed direct testimony, the Access Fee is proposed to provide adequate cost recovery commensurate with the cost responsibility of stand-alone DG facilities. The Company's distribution system is designed and constructed to service the expected maximum needs of all of its customers, including customers with DG. For customers with DG, the amount of infrastructure required to serve that customer is based on the maximum amount of electricity flowing to the customer from the distribution system or flowing back into the distribution system from the DG facility. Therefore, proper cost allocation and cost recovery should recognize demand that results from either inflows or outflows of energy. The proposed Access Fee would contribute towards recovery of the cost of the distribution system that the DG facility relies upon for the movement of generated energy from the site of generation to other locations, as well as contributing towards the recovery of ongoing operation, maintenance, and replacement costs of interconnection equipment. As part of this proposal, the Company will credit any revenue billed through this Access Fee to its RDM reconciliation. Therefore, the Company will not realize incremental revenue from this proposal, but the stand-alone DG facility will pay for its reliance on, and the services provided by, the distribution system that all other customers have been funding.

**Q. How did you calculate the Access Fee in this proceeding?**

A. As described in the Company's direct testimony and the Company's response to Data Request CLF 1-12, the Access Fees are set at levels that reflect the per unit demand-related revenue requirements, as shown on Schedule NG-11, Line 24 (Bates Page 141) for Rates G-32/G-62(primary) and Rate G-02(secondary) and are further adjusted to reflect the relationship between class non-coincident demand, used in the calculation of the Schedule NG-11 per unit charges, and class maximum demands, used for billing purposes.[18]

Once the per-kW value was calculated, the Company then looked to determine the contribution at peak from different DG technologies to determine the proposed availability capacity factors (ACFs). As a participant in ISO-NE's DG forecast working group, the Company has provided (and continues to provide through quarterly updates) the amount of solar interconnected to its distribution systems in Rhode Island and Massachusetts. ISO-NE used this data, along with that of other New England utilities, to determine the percentage of the AC nameplate rating of solar that was present during the ISO-NE system peak hours of 3 p.m. to 5 p.m. As discussed in the Company's pre-filed direct testimony, ISO-NE calculated that the system saw approximately 40 percent of the nameplate generation on peak.[19] The Company compared this to solar on its own system and came up with a similar contribution. The Company then looked at other technologies, notably wind and hydro, to determine their contributions as shown in the chart below:

[18] As indicated in the Pre-Filed Direct Testimony on Access Fee of Abigail Anthony, Ph.D., On Behalf of Acadia Center, page 6, the Company's response to Data Request CLF 1-12 contained an error. The response should have stated that the per-unit charges are further adjusted by approximately 75% (primary) and 85% (secondary).
[19] Zschokke and Lloyd Direct Testimony at Bates Pages 60-61.

| Asset | type | size | Output at Peak (7/30/15 at 4pm) | Percent of nameplate at 2015 peak | Output at Peak (9/2/14 at 2pm) | Percent of nameplate at 2014 peak | Output at Peak (7/19/13 at 3pm) | Percent of nameplate at 2013 peak | Average percentage on peak | Average by technology (ACF) |
|---|---|---|---|---|---|---|---|---|---|---|
| H1 | Hydro | 1,200 | 0.0 | 0.0% | 179.8 | 15.0% | 235.2 | 19.6% | 11.5% | |
| H2 | Hydro | 1,800 | 187.6 | 10.4% | 201.6 | 11.2% | 0 | 0.0% | 7.2% | 9.4% |
| H3 | Hydro | 1200 | 0.0 | 0.0% | 0.0 | 0.0% | 14.7 | 1.2% | 0.4% | 6.4% |
| W1 | Wind | 275 | 0.0 | 0.0% | 36.1 | 13.1% | 50.37 | 18.3% | 15.7% | |
| W2 | Wind | 1,500 | 953.1 | 63.5% | 461.5 | 30.8% | N/A | N/A | 47.2% | 31.4% |
| S1 | Solar | 500 | 210.8 | 42.2% | 332.4 | 66.5% | N/A | N/A | 54.3% | |
| S2 | Solar | 500 | 224.7 | 44.9% | 329.0 | 65.8% | N/A | N/A | 55.4% | |
| S3 | Solar | 4,950 | 1129.8 | 22.8% | 1624.0 | 32.8% | N/A | N/A | 27.8% | |
| S4 | Solar | 4,950 | 1809.2 | 36.5% | 4096.6 | 82.8% | N/A | N/A | 59.7% | |
| S5 | Solar | 4,999 | no data | no data | 2406.6 | 48.1% | N/A | N/A | 48.1% | |
| S6 | Solar | 4,000 | 1100.4 | 27.5% | 1215.2 | 30.4% | N/A | N/A | 28.9% | |
| S7 | Solar | 1,000 | 308.4 | 30.8% | 670.8 | 67.1% | 786.9 | 78.7% | 58.9% | |
| S8 | Solar | 1,000 | 7.7 | 0.8% | 288.4 | 28.8% | 372.4 | 37.2% | 22.3% | 44.4% |

For wind, the Company rounded the percentage to 30 percent and for hydro, the Company rounded the percentage to 10 percent. As anaerobic digesters control their fuel input, the Company assumed the percentage of nameplate to peak to be 100 percent.

**Q. Are there any issues with using cost and usage data from the Company's most recent ACOSS for determining the Access Fee proposal?**

A. No. As indicated elsewhere in this testimony, the most recently approved ACOSS, based on a 2011 test year, is representative of current costs.

**Q. Should the Company have separately evaluated stand-alone DG customers in its ACOSS?**

A. No. For the reasons discussed earlier in this testimony, the Company does not believe that it is necessary to distinguish partial requirements customers from full requirements customers in the ACOSS.

**Q. Is the distribution system cost of facilitating exported generation the same as the cost of providing customer demand for any analogous customer classes?**

A. The distribution system consists primarily of poles, towers, substations and individual feeders emanating from each substation. The capacity of individual feeders is determined by the aggregate capacity requirements of the customers connected to each feeder. The capacity requirements include the capacity necessary to deliver kWh from the substation to the customers and to deliver kWh from the customer to the substation from a stand-alone DG facility. Until such time there is a DG facility in an area where its operation to provide capacity is possible, and the DG facility can be contracted (and is able to) to operate at the same time as the peak load conditions on the feeder, the Company must assume the DG facility will not be operating in order to continue to provide reliable electric service to all other customers on the feeder. The interconnection of stand-alone DG facilities have necessitated upgrades to the electric distribution system, and currently, no facility is able to provide the capacity as described in the preceding sentence. For this reason, the current distribution system requirements of stand-alone DG facilities are the same as customers who do not have DG.

**Q. Why should the charges for the use of the distribution system by stand-alone generators be based on the generation produced at peak periods?**

A. Because this is consistent with how charges are assessed to all other customers, and will produce an equitable allocation of costs based upon the customer's utilization of the system.

**Q. Ms. Carpenter states in her testimony (Bates Page 8) that the Company has described the Access Fee as a back-up charge. Is this correct?**

A. No. A back-up charge is designed to compensate the Company (and other customers) for costs incurred when the DG facility is not operating for a DG customer who has on-site load. That is, the Company must reserve capacity on the distribution system in the event that the DG facility experiences an unexpected outage and the Company must supply the capacity needed for the customer's on-site load. The Access Fee is intended to ensure that the stand-alone DG customer contributes to the cost of the distribution system in exchange for services provided during the times that the system is operating.

**Q. Previously in your testimony, you have discussed the costs associated with stand-alone DG customers. Please explain why those costs are not covered under the charges these customers already pay.**

A. Stand-alone DG customers do not consume much electricity for station service, and therefore, most stand-alone DG facilities currently qualify for the Company's Rate C-06. This rate class has a small customer charge corresponding to the relatively inexpensive meter (see the Company's response to Data Request PUC 1-12) used by most Rate C-06 customers, having a cost of $108.56. In the case of stand-alone DG customers of 60 kWs or greater, the meter needed is the same as those used by Rate G-32/G-62 customers, with digital modem, at a cost of $1,957.08. This meter is needed to provide hourly interval data for ISO-NE settlement of the generation. In addition, unless the DG facility is shut down, these customers do not pay any charges if the generated amount of energy and the corresponding payments for that energy received by the DG customer exceed the small customer charge for Rate C-06.

**Q. Does the Company currently recover all costs of the equipment needed to interconnect the DG facility of a stand-alone DG customer?**

A. No. The cost to interconnect a customer to the distribution system includes not only the infrastructure necessary to perform the required connection, but also ongoing operation and maintenance cost associated with that equipment. Currently, the Company recovers the direct cost of the infrastructure as part of the initial interconnection; however, because stand-alone DG customers pay only a small monthly customer charge, the Company is not being compensated for the ongoing operation and maintenance cost of the equipment. This cost is initially borne by the Company but, ultimately, will be reflected in the overall revenue requirement in subsequent general rate cases and recovered from all other customers through distribution rates. In addition, the monthly customer charge for stand-alone DG customers that are served under Rate C-06, which is intended to recover the cost of a simple watt-hour meter, meter reading and billing expenses, and other customer care expense, is $10.00 per month, far less than the charge necessary to recover the cost of the required interval meter with communication capabilities installed on these customers as discussed above.

**Q. Ms. Carpenter states in her testimony (Bates Page 10) that the costs of DG are more than offset by the benefits. Please comment?**

A. Ms. Carpenter has provided no justification for that statement.

**Q. Ms. Carpenter states that a fair rate structure would balance the benefits of DG with the costs. Do you agree?**

A. Absolutely. In fact, that is the Company's proposal. The costs associated with providing service to DG customers should be charged to those customers in the form of a distribution system Access Fee. The benefits that those customers provide to the distribution system should be, and already are, recognized as part of the compensation provided to DG customers. Thus, the benefits provided by the DG customers are balanced with the costs that those customers incur.

**Q. In its October 30, 2015 letter to the PUC filed in this docket, the Company indicated that it was considering a refinement to its Access Fee proposal to "grandfather" certain stand-alone distributed generators that are directly connected to the distribution system and have no associated on-site load, other than station service.**

**Has the Company determined whether it would consider "grandfathering" these DG projects from the assessment of the Access Fee?**

A. Yes. The Company would consider a "grandfathering" proposal such that the proposed Access Fee would not apply to the initial customer of record for a project that qualifies for, and participates in, one of the following programs under the program's terms and conditions as approved by the PUC: (i) Long-term Contracting Standard for Renewable Energy and DG Standard Contracts Program, (ii) RE Growth Program, and (iii) Net Metering Provision tariff R.I.P.U.C. No. 2150 (as may be amended) or Qualifying facilities Power Purchase Rate tariff R.I.P.U.C. No. 2098, as such programs and tariffs may be amended from time to time, subject to the provisions discussed below.

**Q. Please elaborate on which projects would qualify the initial customer of record for grandfathered status from the assessment of the Access Fee.**

A. Certainly. These projects would include a project with respect to which the Company, and the project owner have entered into a Long-term Contracting or DG Standard Contract, which is in full force and effect as of the date the Access Fee is approved by the PUC. All other projects would qualify for grandfathered status from the assessment of the Access Fee only if a complete interconnection application for the project is received by the Company no later than by December 31, 2016. Projects intending to participate in the RE Growth Program will also need to have received the Certificate of Eligibility awarded by the Company or the PUC by July 1, 2017.

For projects that meet the qualifications discussed above, the initial customer of record for such project would have grandfathered status from the assessment of the Access Fee for only so long as there is no change in project ownership after the initial date of the project's qualification in such program. If there is such a change in project ownership, or the customer of record, the Access Fee shall apply to the project prospectively.

**Q. Ms. Carpenter states (page 10) that the costs of the Access Fee will be result in an escalation of ceiling prices. Do you agree?**

A. Again, Ms. Carpenter has not presented any evidence to support that statement. Ceiling prices are based on a number of factors. Prices for 2016 are lower than 2015 prices. There is currently no reason to believe that the Access Fee would outweigh any of the other factors that might have a downward effect on prices.

**Q. Did the Company notify developers of stand-alone projects of a potential Access Fee?**

A. Yes. As the Company agreed at the PUC's September 17, 2015 technical record session in this docket, the Company notified the designated point of contact for each of the stand-alone DG facilities listed in the Company's response to Data Request PUC 1-18.[20]

[20] See also the Company's supplemental response to Data Request OER 3-1, at Bates Page 2.

**Q. Does the Company intend to notify developers of future stand-alone DG projects of a potential Access Fee?**

A. If the Access Fee is approved, as part of the interconnection process, the Company will let parties know that an Access Fee would be applicable once the details of a proposed interconnection are known.

**Q. How would the Access Fee be calculated for future stand-alone projects?**

A. The Access Fee would be calculated in the same way as it has been proposed initially.

**Q. What is the added cost of the Access Fee to virtual net metering projects approved under the state's net metering law?**

A. If the Access Fee is approved as filed, a stand-alone DG project would be assessed the fee. As a virtual net metering facility is also a stand-alone project, it would be assessed the Access Fee. The costs will depend on the technology used as well as the size. The Company has previously provided an estimate of the Access Fee calculation in its supplemental response to Data Request PUC 1-18.

**Q. What effect would the Access Fee have on the future of renewable energy industry in Rhode Island?**

A. An Access Fee would allow renewable energy projects to continue to move forward with the understanding that proper funding of the distribution system is critical as an essential element of the overall electric power system the project needs to provide renewable energy to all customers.

**Q. Can you please explain why it is more equitable to recover costs through the proposed Access Fee rather than through the Company's RDM?**

A. Customers who utilize the distribution system for any purposes, either import or export of power, should fairly pay for the support of the system. If stand-alone DG customers do not pay for their use of the distribution system, then all other customers ultimately pay those costs as part of base distribution rates. The costs paid by all other customers become a non-transparent form of additional compensation to DG customers. Even if the cost incurred by DG customers associated with being assessed the Access Fee is ultimately included as part of the compensation provided to DG customers through performance-based incentive payments, and passed on to all other customers through the RE Growth Program cost recovery mechanism, the Company still believes that this results in a more transparent recognition of this additional benefit provided to DG customers.

**Q. Some parties have suggested that the PUC should reject the proposed Access Fee and order the parties to work collaboratively to conduct a full valuation analysis of the costs and benefits of stand-alone generators. Do you agree?**

A. No. Valuing the costs and benefits of DG continues to be the subject of extensive debate across the industry. In time, all parties will have a better sense of these values, and when there is consensus on this point, there may be reason to re-visit an Access Fee construct. A collaborative process among parties with competing agendas will only be successful if the parties are willing to compromise on issues within their specific agendas in order to reach resolution. Although the idea of a collaborative process is appealing, the Company is doubtful that, in this case, such a process will result in an acceptable solution.

**Q. Does the Company have any recommendations for the PUC other than approval of the proposed Access Fee?**

A. If the PUC determines that the proposed Access Fee is not appropriate at this time, then the Company requests that the PUC, at a minimum, direct that stand-alone DG customers that are in excess of 200 kW receive retail delivery service on Rate G-32, which has a customer charge that is more commensurate with the cost incurred to serve larger customers. In addition, the Company requests that the PUC direct the Company to develop a charge applicable to all DG customers that will recover the ongoing operation and maintenance expense associated with the interconnection facilities installed to serve the customer.

## VI. Seven Balancing Factors Under Section 24

**Q. Intervenors criticize the Company's proposal as not consistent with the seven factors listed in Section 24. Has the Company considered each factor and addressed them in this proceeding?**

A. The Company has considered six of the seven factors and addressed them in the following documents in this proceeding.

(1) The Company has addressed the potential benefits of distributed energy resources throughout this proceeding: (Direct Testimony at Bates Pages 39-40; Schedule NG-5, Estimate of Installed DG in RI Through 2020 (at Bates Page 127); Schedule NG-3, the EPRI Paper (at Bates Page 79); Responses to Data Requests Division 1-4 and WED 1-13; and Rebuttal Testimony at Section III). The Company has concluded that, based on currently available information, the potential reliability and capacity benefits of such resources to the distribution system are minimal.

(2) The Company has addressed the distribution services being provided to net-metered customers when the distributed generation is not producing electricity: (Direct Testimony at Bates Pages 13-14, 17-19; the EPRI Paper, Schedule NG-3 (at Bates Page 79); and Response to Data Request Division 1-23). The Company has concluded that, for customers with generation, the amount of distribution infrastructure required to serve that customer may not be based only upon the

energy that the customer is using, but also the energy that the customer is generating. Therefore, the proper cost allocation and rate design must recognize the cost responsibility of the customer for the total of its electricity needs, including when the generator's output exceeds the customer's usage on-site, and when the generator is not operating at all. Moreover, given the services provided to DG by the distribution company, including reliability, voltage quality, access to energy markets, startup power and efficiency, the distribution company is a required complement to the expansion of clean renewable power because it lowers the overall cost for an individual or company to consider renewable self-generation.

(3) The Company has developed <u>simple, understandable and transparent rates to all customers, including non-net metered and net-metered customers</u>: (Schedule NG-14, Individual Customer Bill Impacts (at Bates Page 165); Schedule NG-13, Typical Bills (at Bates Page 147); and Response to Data Request Division 1-9).

(4) The Company has used e<u>quitable ratemaking principles to allocate the costs of the distribution system to all customers</u>: (Direct Testimony at Bates Pages 13-14, 22-23, 27; Schedule NG-10, Results of ACOSS and Distribution Revenue [Schedule JAL-1] (at Bates Page 138); Schedule NG-11, ACOSS Unit Costs – Compliance Filing in Docket No. 4323 (at Bates Page 141); Schedule NG-13, Typical Bills (at

Bates Page 147); Schedule NG-14, Individual Customer Bill Impacts (at Bates Page 165); and Responses to Data Requests CLF 1-4, CLF 1-6, CLF 1-7, CLF 1-8, Division 1-6, Division 1-8, and Division 1-25).

(5) The Company has developed rates for this proceeding <u>consistent with cost causation principles</u> (Direct Testimony at Bates Pages at 18-21, 27, 28-38, 57, 59-66; Schedule NG-10, Results of ACOSS and Distribution Revenue [Schedule JAL-1] (at Bates Page 138); Schedule NG-11, ACOSS Unit Costs – Compliance Filing in Docket No. 4323 (at Bates Page 141); and Responses to Data Requests CLF 1-4, CLF 1-9, CLF 1-16, and Division 1-24).

(6) The Company has developed rates for this proceeding <u>consistent with the general assembly's legislative purposes in creating the RE Growth Program</u>, and Section 24 in particular: (Direct Testimony at Bates Pages at 13-18; Responses to Data Requests CLF 1-14, CLF 1-15, Division 1-4, and Division 1-7; and Rebuttal Testimony, Section III). The purpose of Section 24 is for the PUC to "determine the appropriate cost responsibility and contributions to the operation, maintenance and investment in the distribution system that is relied upon by all customers, including, without limitation, non-net metered and net metered customers".

The Company will address the last factor (i.e., "any other factors the commission deems relevant and appropriate in establishing a fair rate structure"), if anything additional arises, during evidentiary hearings scheduled for this proceeding.

The PUC has clear discretion to balance these factors and others that it deems relevant and reasonable, in establishing fair rates. The statute requires that the PUC "consider" these factors and does not require the PUC to place more weight on any one factor than another. By requiring the PUC to balance these criteria, the legislature recognized that these factors may represent competing interests. It is up to the PUC to prioritize the factors in a way that they believe is in the best interest of all customers, both DG and non-DG customers, and that meet the intent of the provisions of Section 24.

## VII. <u>Conclusion</u>

**Q. Do you have any general concluding remarks?**

A. The Company has put forth a thoughtful proposal required by the Act, proposing specific rate design changes with accompanying support that address the requirements of Section 24. The Company respectfully requests that the PUC approve the Company's rate design proposal as described in its pre-filed direct testimony, or alternatively, with the modifications as proposed in this rebuttal testimony.

**Q. Does this conclude your testimony?**

A. Yes.

**The Narragansett Electric Company**
**Typical Bill - Basic Residential (Rate A-16) Customer Showing Subsidy and Public Policy Programs**

Monthly Usage 500 kWh

| Line | | Current Rates | Bill Charges | % of Tot Bill |
|---|---|---|---|---|
| 1 | **Commodity Service** | | | |
| 2 | Standard Offer Charge | $0.10111 | $50.56 | 51.1% |
| 3 | | | | |
| 4 | **Delivery Service** | | | |
| 5 | Transmission Energy Charge | $0.02348 | $11.74 | 11.9% |
| 6 | | | | |
| 7 | Transition Energy Charge | ($0.00201) | ($1.01) | -1.0% |
| 8 | | | | |
| 9 | Distribution | | | |
| 10 | Customer Charge | $5.00 | $5.00 | 5.0% |
| 11 | Distribution Energy Charge | $0.03731 | $18.66 | 18.8% |
| 12 | | | | |
| 13 | Subtotal Distribution | | $23.66 | 23.9% |
| 14 | | | | |
| 15 | **Total Delivery Service** | | $34.39 | 34.7% |
| 16 | | | | |
| 17 | **Subsidies Provided to Other Classes** | | | |
| 18 | | | | |
| 19 | Low Income | | | |
| 20 | LIHEAP Charge | $0.73 | $0.73 | 0.7% |
| 21 | Subsidy In Base Rates | $0.00121 | $0.60 | 0.6% |
| 22 | Subtotal - Low Income | | $1.33 | 1.3% |
| 23 | | | | |
| 24 | Subsidies to Other Classes | | | |
| 25 | Subsidy to Rate G-62/X-01 | $0.00104 | $0.52 | 0.5% |
| 26 | Subsidy to Outdoor Lighting | $0.00108 | $0.54 | 0.5% |
| 27 | Subtotal - Other Classes | | $1.06 | 1.1% |
| 28 | | | | |
| 29 | **Subtotal Subsidies to Other Classes** | | $2.40 | 2.4% |
| 30 | | | | |
| 31 | **Public Policy Programs** | | | |
| 32 | Energy Efficiency Program Charge | $0.00953 | $4.77 | 4.8% |
| 33 | | | | |
| 34 | Renewables Programs | | | |
| 35 | Renewable Energy Distribution Charge | $0.00232 | $1.16 | 1.2% |
| 36 | RE Growth Program | $0.17 | $0.17 | 0.2% |
| 37 | Renewable Egy Std Charge | $0.00294 | $1.47 | 1.5% |
| 38 | Renewable Fund | $0.00030 | $0.15 | 0.2% |
| 39 | Subtotal Renewables Programs | | $2.95 | 3.0% |
| 40 | | | | |
| 41 | **Total Public Policy Programs** | | $7.72 | 7.8% |
| 42 | | | | |
| 43 | Subtotal before GET | | $95.07 | 96.0% |
| 44 | | | | |
| 45 | **Gross Earnings Tax** | 4% | $3.96 | 4.0% |
| 46 | | | | |
| 47 | **Total Bill including GET** | | $99.03 | 100.0% |

******Based on Rates in effect as of July 1, 2015**

Footnotes:

Line 21: Subsidy of $3,421,093 from Docket 4323 Compliance Attachment 3B, Column (b), line 30 ÷ by A-16 kWh of 2,830,141,506 from Docket 4323 Compliance Attachment 3D, page (2), Column (a), Line (10), truncated to 5 decimal places

Line 25: (Subsidy of $2,799,800 from Docket 4323 Compliance Attachment 3B, Column (f), line 42 + subsidy of $154,200 from column (h), line 42) ÷ by A-16 kWh of 2,830,141,506 from Docket 4323 Compliance Attachment 3D, page (2), Column (a), Line (10), , truncated to 5 decimal places

Line 26: Subsidy of $3,066,293 from Docket 4323 Compliance Attachment 3B, Column (g), line 42 ÷ by A-16 kWh of 2,830,141,506 from Docket 4323 Compliance Attachment 3D, page (2), Column (a), Line (10), , truncated to 5 decimal places

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4568
In Re: Review of Electric Distribution Rate Design
Pursuant to R.I. Gen. Laws § 39-26.6-24
Responses to Green Development, LLC
d/b/a Wind Energy Development, LLC's First Set of Data Requests
Issued on September 4, 2015

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WED 1-13

Request:

Is "The Integrated Grid" the only secondary source you used to evaluate the costs and benefits of distributed generation? If not, please list any other resources you relied on. Are you aware of other resources that would inform this process (please include those that do not or might not support your position)?

Response:

National Grid is aware of many reports, papers, and articles published in the recent past on the subject of the cost and benefits of distributed generation. Listed below are several that provided background, information, and points of view that the Company took into consideration in developing its rate re-design proposal. National Grid agrees with some of the analyses, and does not agree with others, but all of this work was informative in the rate design process.

- "The Future of Solar Energy" – MIT Energy Initiative Report, Massachusetts Institute of Technology, February 2015
- "A Policy Framework for Designing Distributed Energy Tariffs" – Edison Electric Institute, Nov. 2013
- "Ratemaking, Solar Value and Solar Net Energy Metering: A Primer," Solar Electric Power Association, Version 1.0
- "Rate Design for the Distribution Edge: Electricity Pricing for Distributed Resource Future," Rocky Mountain Institute, August 2014
- "A Review of Solar PV Benefit & Cost Studies, 2nd Edition," Rocky Mountain Institute, September 2013
- "Rethinking Standby & Fixed Cost Charges: Regulatory and Rate Design Pathways to Deeper Solar PV Cost Reductions," NC Clean Energy Technology Center and Meister Consulting group, August 2014

Prepared by or under the supervision of: Peter T. Zschokke and Jeanne A. Lloyd

The Narragansett Electric Company
d/b/a National Grid
RIPUC Docket No. 4568
In Re: Review of Electric Distribution Rate Design
Pursuant to R.I. Gen. Laws § 39-26.6-24
Responses to Green Development, LLC
d/b/a Wind Energy Development, LLC's First Set of Data Requests
Issued on September 4, 2015

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WED 1-13, page 2

- "Valuation of Distributed Solar: A Qualitative View," The Electricity Journal, Dec. 2014, Brown, Ashley and Jillian Bunyan.

- "Maine Distributed Solar Valuation Study," Presented to the Maine Legislature, Joint Committee on Energy Utilities and Technology, March 1, 2015

- "The True Value of Solar," ICF International White Paper, Fine, et al. 2014

- "The Report of the Net Metering and Solar Task Force," Presented to the Massachusetts Legislature, Joint Committee on Technology, Utilities and Energy, April 2015

- "Comparative Generation Costs of Utility Scale and Residential Scale PV in Xcel Energy's Colorado Service Territory," Prepared for First Solar by the Brattle Group, July 2015

Prepared by or under the supervision of: Peter T. Zschokke and Jeanne A. Lloyd

nationalgrid

**ELECTRIC BILL**

SERVICE FOR
[redacted]

BILLING PERIOD
Oct 4, 2015 to Nov 2, 2015

PAGE **1 of 2**

ACCOUNT NUMBER
[redacted]

PLEASE PAY BY
Nov 29, 2015

AMOUNT DUE
**$ 59.60**

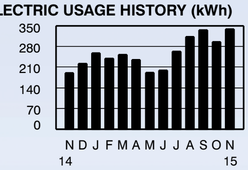
www.nationalgridus.com
CUSTOMER SERVICE
**1-800-322-3223**
CREDIT DEPARTMENT
**1-888-211-1313**
GAS EMERGENCIES
**1-800-640-1595**
POWER OUTAGE OR DOWNED LINE
**1-800-465-1212**
CONTACT US
ngrid.com/ri-contactus
CORRESPONDENCE ADDRESS
**PO Box 960**
**Northborough, MA 01532-0960**
PAYMENT ADDRESS
**PO Box 11739**
**Newark, NJ 07101-4739**

DATE BILL ISSUED
**Nov 5, 2015**

**Enrollment Information**

To enroll with a supplier or change to another supplier, you will need the following information about your account:
Loadzone Rhodelsland
**Acct No:** [redacted] **Cycle:** 6,[redacted]

**ELECTRIC USAGE HISTORY (kWh)**




| Daily Averages | Nov 14 | Nov 15 |
|---|---|---|
| kWh | 6.8 | 11.8 |
| Cost | $ 1.03 | $ 2.05 |

■ Actual ☐ Estimated

## ACCOUNT BALANCE

| | | |
|---|---|---|
| Previous Balance | | 52.10 |
| Payment Received on OCT 26 (*Check*) | *THANK YOU* | - 52.10 |
| Current Charges | | + 59.60 |
| | **Amount Due ▶** | **$ 59.60** |

## SUMMARY OF CURRENT CHARGES

| | DELIVERY SERVICES | SUPPLY SERVICES | OTHER CHARGES/ ADJUSTMENTS | TOTAL |
|---|---|---|---|---|
| Electric Service | 21.73 | 35.48 | | 57.21 |
| Other Charges/Adjustments | | | 2.39 | 2.39 |
| **Total Current Charges** | **$ 21.73** | **$ 35.48** | **$ 2.39** | **$ 59.60** |

Save time and money! Sign up for paperless billing and receive a $ 0.34 credit on your monthly bill. Visit our website to enroll today.

The Energy Charge now includes the Renewable Energy Standard Charge which was previously identified separately on the bill. This charge is collected for the purpose of acquiring a portion of Rhode Island's energy supply from renewable energy resources, as required by Rhode Island General Laws section 39-26-1 .

**What is the Energy Efficiency Charge on my bill?** This charge funds Energy Efficiency programs that can help consumers lower their energy usage and bills, improve comfort in their homes or businesses, and lower pollutants and carbon emissions in our communities. To learn how to take advantage of these programs and your eligibility, please call 1-866-903-2811 or visit www.ngrid.com/ri-ee.

★ **WILL WE BE ABLE TO REACH YOU DURING A POWER OUTAGE?:** During a power outage, phones with a direct link to a local phone line are able to operate. Phones that are **not** directly linked (for example, wireless phones with answering machines) need electricity to make/receive calls. If you would like to register another phone number, such as a cell phone, as your account's primary phone number, please go to www.nationalgrid.com/myaccount to update your information so that we may be able to reach you with important information during power outages.

KEEP THIS PORTION FOR YOUR RECORDS.

RETURN THIS PORTION WITH YOUR PAYMENT.

nationalgrid

PO Box 960
Northborough MA 01532

| ACCOUNT NUMBER | PLEASE PAY BY | AMOUNT DUE |
|---|---|---|
| | **Nov 29, 2015** | **$ 59.60** |

ENTER AMOUNT ENCLOSED
$

*Write account number on check and make payable to National Grid*

[redacted]

005732

NATIONAL GRID
PO BOX 11739
NEWARK NJ 07101-4739

[redacted]

nationalgrid

SERVICE FOR
[redacted]

BILLING PERIOD
Oct 4, 2015 to Nov 2, 2015



ACCOUNT NUMBER [redacted]

PLEASE PAY BY Nov 29, 2015

AMOUNT DUE $ 59.60

**Enrollment Information**

To enroll with a supplier or change to another supplier, you will need the following information about your account:

**Loadzone** RhodeIsland

**Acct No:** [redacted] **Cycle:** 6[redacted]

**Electric Usage History**

| Month | kWh | Month | kWh |
|---|---|---|---|
| Nov 14 | 191 | Jun 15 | 200 |
| Dec 14 | 222 | Jul 15 | 265 |
| Jan 15 | 259 | Aug 15 | 315 |
| Feb 15 | 240 | Sep 15 | 337 |
| Mar 15 | 253 | Oct 15 | 298 |
| Apr 15 | 237 | Nov 15 | 341 |
| May 15 | 194 | | |

## DETAIL OF CURRENT CHARGES

### *Delivery Services*

| Service Period | No. of days | Current Reading | - | Previous Reading | = | Total Usage |
|---|---|---|---|---|---|---|
| Oct 4 - Nov 2 | 29 | 65430 *Actual* | | 65089 *Actual* | | 341 kWh |

**METER NUMBER** 10443629 **NEXT SCHEDULED READ DATE ON OR ABOUT** Dec 7

**RATE** Low Income Rate A-60

| | | | | |
|---|---|---|---|---|
| LIHEAP Enhancement Charge | | | | 0.73 |
| Distribution Energy Chg | 0.02749032 | x | 341 kWh | 9.37 |
| Renewable Egy Dist Chg | 0.00232 | x | 341 kWh | 0.79 |
| Transmission Charge | 0.02348 | x | 341 kWh | 8.01 |
| Transition Charge | -0.00201 | x | 341 kWh | -0.69 |
| Energy Efficiency Prgrms | 0.00983 | x | 341 kWh | 3.35 |
| RE Growth Program | | | | 0.17 |
| | | | **Total Delivery Services** | **$ 21.73** |

### *Supply Services*

**SUPPLIER** National Grid

| | | | | |
|---|---|---|---|---|
| Energy Charge | 0.10405 | x | 341 kWh | 35.48 |
| | | | **Total Supply Services** | **$ 35.48** |

### *Other Charges/Adjustments*

| | | | | |
|---|---|---|---|---|
| Gross Earnings Tax | 0.04166667 | x | 57.21 | 2.39 |
| | | | **Total Other Charges/Adjustments** | **$ 2.39** |

### Right To Dispute Your Bill And To An Impartial Hearing

If you believe your bill is inaccurate or for any reason payment may be withheld, you should first contact our Customer Service Department at 1-800-322-3223. If a mutually satisfactory settlement of this matter cannot be made, you have the right to submit this matter to: Reviewing Officer, Division of Public Utilities and Carriers, 89 Jefferson Blvd., Warwick, Rhode Island 02888 Telephone: 401-780-9700. National Grid will not disconnect your service pending proceedings before a reviewing officer appointed by the Public Utilities Administrator.

**LIHEAP Charge**

This charge is required under Rhode Island law and will be used to provide funding for a Low-Income Home Energy Assistance Program ("LIHEAP") Enhancement Plan, designed to assist low-income electric and natural gas households with their home energy and heating needs. By law, this charge may not be more than $10 per year for each electric or natural gas service account.

### Explanation of Billing Terms Available

If you would like an explanation of any of the terms used on your bill, you may find them on our web site at www.nationalgrid.com or you may call us at 1-800-322-3223.

### Right To Electric Service:

**During Serious Illness:** If you or anyone presently and normally living in your home is seriously ill, we will not discontinue your electric service during such illness providing you: have a registered physician certify in writing to us that such illness exists, the nature and duration of the illness and you make satisfactory arrangements to pay your bill. This certification must be received within seven (7) days from the date that your physician initially contacts our Credit Department at 1-888-211-1313.

**You have a child under twenty four months and a financial hardship:** If you or anyone presently and normally living in your home has a child under twenty four months old we will not terminate your electric service, provided you also have a financial hardship. Please call our Credit Department at 1-888-211-1313 immediately if this applies to you.

### Termination of Service to Elderly or Handicapped Persons

If all residents in your household are 62 years of age or older or if any resident in your household is handicapped, the Company will not terminate your service for failure to pay the past due bill without written approval from the Division of Public Utilities. If you cannot pay your bill all at once, you may be able to work out a payment plan with the Company. The Elderly or Handicapped Forms that must be filled out are available at the Company. The Form also enables you to participate in "Third Party Notification". If you have any questions or want further information, call the Credit Department at 1-888-211-1313.

**The Narragansett Electric Company**
**Typical Bill - Basic Residential (Rate A-16) Customer: Illustrative Electric Space Heating Customer**

| **Monthly Usage** | | | | **Average Usage** |
|---|---|---|---|---|
| January | 710 | July | 351 | 500 |
| February | 742 | August | 437 | |
| March | 750 | September | 475 | |
| April | 400 | October | 461 | |
| May | 330 | November | 380 | |
| June | 333 | December | 634 | |

| | | Current Rates | Bill Charges | Annual Bill Charges | Proposed Rates | Proposed Bill Charges | Proposed Annual Bill Charges | Annual Difference | % Annual Difference |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Customer Charge | $5.00 | $5.00 | $60.00 | $8.50 | $8.50 | $102.00 | $42.00 | 70.0% |
| 2 | Distribution Energy Charge | $0.04065 | $20.33 | $243.96 | $0.03026 | $15.13 | $181.56 | ($62.40) | -25.6% |
| 3 | Subtotal Distribution | | $25.33 | $303.96 | | $23.63 | $283.56 | ($20.40) | -6.7% |
| 4 | LIHEAP Charge | $0.73 | $0.73 | $8.76 | $0.73 | $0.73 | $8.76 | $0.00 | 0.0% |
| 5 | Transmission Energy Charge | $0.02348 | $11.74 | $140.88 | $0.02348 | $11.74 | $140.88 | $0.00 | 0.0% |
| 6 | Transition Energy Charge | ($0.00201) | ($1.01) | ($12.12) | ($0.00201) | ($1.01) | ($12.12) | $0.00 | 0.0% |
| 7 | Energy Efficiency Program Charge | $0.00983 | $4.92 | $59.04 | $0.00983 | $4.92 | $59.04 | $0.00 | 0.0% |
| 8 | Renewable Energy Distribution Charge | $0.00232 | $1.16 | $13.92 | $0.00232 | $1.16 | $13.92 | $0.00 | 0.0% |
| 9 | RE Growth Program | $0.17 | $0.17 | $2.04 | $0.17 | $0.17 | $2.04 | $0.00 | 0.0% |
| 10 | Subtotal Other Delivery Service | | $17.71 | $212.52 | | $17.71 | $212.52 | $0.00 | 0.0% |
| 11 | Standard Offer Charge | $0.10111 | $50.56 | $606.72 | $0.10111 | $50.56 | $606.72 | $0.00 | 0.0% |
| 12 | Renewable Egy Std Charge | $0.00294 | $1.47 | $17.64 | $0.00294 | $1.47 | $17.64 | $0.00 | 0.0% |
| 13 | Subtotal Supply Service | | $52.03 | $624.36 | | $52.03 | $624.36 | $0.00 | 0.0% |
| 14 | Subtotal before GET | | $95.07 | $1,140.84 | | $93.37 | $1,120.44 | ($20.40) | -1.8% |
| 15 | Gross Earnings Tax | 4% | $3.96 | $47.52 | 4% | $3.89 | $46.68 | ($0.84) | -1.8% |
| 16 | Total Bill including GET | | $99.03 | $1,188.36 | | $97.26 | $1,167.12 | ($21.24) | -1.8% |

******Based on Rates in effect as of July 1, 2015**

**The Narragansett Electric Company**
**Typical Bill - Basic Residential (Rate A-16): Illustrative Customer with an Electric Vehicle**

| **Monthly Usage** | Before | After | | Before | After |
|---|---|---|---|---|---|
| January | 332 | 712 | July | 734 | 1,114 |
| February | 520 | 900 | August | 649 | 1,029 |
| March | 324 | 704 | September | 359 | 739 |
| April | 511 | 891 | October | 292 | 672 |
| May | 524 | 904 | November | 392 | 772 |
| June | 638 | 1,018 | December | 569 | 949 |

| **Average Usage** | |
|---|---|
| Before | After |
| 487 | 867 |

**A. Current Rates**

| | | BEFORE | | | AFTER | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Current Rates | Bill Charges | Annual Bill Charges | Current Rates | Bill Charges | Annual Bill Charges | Annual Difference | % Annual Difference |
| 1 | Customer Charge | $5.00 | $5.00 | $60.00 | $5.00 | $5.00 | $60.00 | $0.00 | 0% |
| 2 | Distribution Energy Charge | $0.04065 | $19.80 | $237.60 | $0.04065 | $35.24 | $422.88 | $185.28 | 78% |
| 3 | Subtotal Distribution | | $24.80 | $297.60 | | $40.24 | $482.88 | $185.28 | 62% |
| 4 | LIHEAP Charge | $0.73 | $0.73 | $8.76 | $0.73 | $0.73 | $8.76 | $0.00 | 0% |
| 5 | Transmission Energy Charge | $0.02348 | $11.43 | $137.16 | $0.02348 | $20.36 | $244.32 | $107.16 | 78% |
| 6 | Transition Energy Charge | ($0.00201) | ($0.98) | ($11.76) | ($0.00201) | ($1.74) | ($20.88) | ($9.12) | 78% |
| 7 | Energy Efficiency Program Charge | $0.00983 | $4.79 | $57.48 | $0.00983 | $8.52 | $102.24 | $44.76 | 78% |
| 8 | Renewable Energy Distribution Charge | $0.00232 | $1.13 | $13.56 | $0.00232 | $2.01 | $24.12 | $10.56 | 78% |
| 9 | RE Growth Program | $0.17 | $0.17 | $2.04 | $0.17 | $0.17 | $2.04 | $0.00 | 0% |
| 10 | Subtotal Other Delivery Service | | $17.27 | $207.24 | | $30.05 | $360.60 | $153.36 | 74% |
| 11 | Standard Offer Charge | $0.10111 | $49.24 | $590.88 | $0.10111 | $87.66 | $1,051.92 | $461.04 | 78% |
| 12 | Renewable Egy Std Charge | $0.00294 | $1.43 | $17.16 | $0.00294 | $2.55 | $30.60 | $13.44 | 78% |
| 13 | Subtotal Supply Service | | $50.67 | $608.04 | | $90.21 | $1,082.52 | $474.48 | 78% |
| 14 | Subtotal before GET | | $92.74 | $1,112.88 | | $160.50 | $1,926.00 | $813.12 | 73% |
| 15 | Gross Earnings Tax | 4% | $3.86 | $46.32 | 4% | $6.69 | $80.28 | $33.96 | 73% |
| 16 | Total Bill including GET | | $96.60 | $1,159.20 | | $167.19 | $2,006.28 | $847.08 | 73% |

******Based on Rates in effect as of July 1, 2015**

**B. Proposed Rates**

| | | BEFORE | | | AFTER | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Proposed Rates | Proposed Bill Charges | Proposed Annual Bill Charges | Proposed Rates | Proposed Bill Charges | Proposed Annual Bill Charges | Annual Difference | % Annual Difference |
| 17 | Customer Charge | $8.50 | $8.50 | $102.00 | $13.00 | $13.00 | $156.00 | $54.00 | 53% |
| 18 | Distribution Energy Charge | $0.03026 | $14.74 | $176.88 | $0.03026 | $26.24 | $314.88 | $138.00 | 78% |
| 19 | Subtotal Distribution | | $23.24 | $278.88 | | $39.24 | $470.88 | $192.00 | 69% |
| 20 | LIHEAP Charge | $0.73 | $0.73 | $8.76 | $0.73 | $0.73 | $8.76 | $0.00 | 0% |
| 21 | Transmission Energy Charge | $0.02348 | $11.43 | $137.16 | $0.02348 | $20.36 | $244.32 | $107.16 | 78% |
| 22 | Transition Energy Charge | ($0.00201) | ($0.98) | ($11.76) | ($0.00201) | ($1.74) | ($20.88) | ($9.12) | 78% |
| 23 | Energy Efficiency Program Charge | $0.00983 | $4.79 | $57.48 | $0.00983 | $8.52 | $102.24 | $44.76 | 78% |
| 24 | Renewable Energy Distribution Charge | $0.00232 | $1.13 | $13.56 | $0.00232 | $2.01 | $24.12 | $10.56 | 78% |
| 25 | RE Growth Program | $0.17 | $0.17 | $2.04 | $0.17 | $0.17 | $2.04 | $0.00 | 0% |
| 26 | Subtotal Other Delivery Service | | $17.27 | $207.24 | | $30.05 | $360.60 | $153.36 | 74% |
| 27 | Standard Offer Charge | $0.10111 | $49.24 | $590.88 | $0.10111 | $87.66 | $1,051.92 | $461.04 | 78% |
| 28 | Renewable Ege Std Charge | $0.00294 | $1.43 | $17.16 | $0.00294 | $2.55 | $30.60 | $13.44 | 78% |
| 29 | Subtotal Supply Service | | $50.67 | $608.04 | | $90.21 | $1,082.52 | $474.48 | 78% |
| 30 | Subtotal before GET | | $91.18 | $1,094.16 | | $159.50 | $1,914.00 | $819.84 | 75% |
| 31 | Gross Earnings Tax | 4% | $3.80 | $45.60 | 4% | $6.65 | $79.80 | $34.20 | 75% |
| 32 | Total Bill including GET | | $94.98 | $1,139.76 | | $166.15 | $1,993.80 | $854.04 | 75% |

******Based on Rates in effect as of July 1, 2015**