Celia B. O'Brien
Assistant General Counsel and Director

September 14, 2015

BY 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
Responses to Division Data Requests – Set 1

Dear Ms. Massaro:

On behalf of National Grid[1], I enclose ten (10) copies of the Company's responses to the first set of data requests issued by the Division of Public Utilities and Carriers on August 24, 2015 in the above-referenced docket.

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

Enclosures

cc: Docket 4568 Service List
Leo Wold, Esq.
Karen Lyons, Esq.
Steve Scialabba, Division

[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.

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.

Celia B. O'Brien

Celia B. O'Brien, Esq. — September 14, 2015 (Date)

Docket No. 4568 National Grid's Rate Design Pursuant to R.I. Gen. Laws Sec 39-26.6-24
Service List updated 9/8/15

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File an original & 9 copies w/ PUC: Luly E. Massaro, Commission Clerk **Public Utilities Commission** 89 Jefferson Blvd. Warwick, RI 02888	Luly.massaro@puc.ri.gov; Cynthia.wilsonfrias@puc.ri.gov; Alan.nault@puc.ri.gov; Todd.bianco@puc.ri.gov;	401-780-2107
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Division 1-1

Request:

Please provide live Excel spreadsheets of Schedules NG-7, NG-10, NG-11, and NG-14 and Workpaper NG-1.

Response:

The Company is providing Schedules NG-7, NG-10, and NG-14 in Excel format. Please note that Schedule NG-10 is the tab JAL-1 from Docket No. 4323 Compliance Schedule JAL 1_3_4-S Compliance. Workpaper NG-1 is the Company's allocated cost of service study submitted in Docket No. 4323. The Company does not have a live, working excel file for Workpaper NG-1 as the allocated cost of service study was prepared for the Company by an outside consultant. Please note that Schedule NG-11 is also part of the allocated cost of service study and is not available in live excel format. The Company has informed the Division and expects to further discuss the extent to which the requested information can be provided in a working format. Based on those discussions, the Division indicated that the request for Workpaper NG-1 (including Schedule NG-11) may be redrafted and reissued.

Division 1-2

Request:

Regarding discussion on p. 9 of the Company's joint pre-filed direct testimony, please discuss the modifications to the billing system that are required to implement the new rates. Provide an estimate of these costs and describe how these estimates were derived.

Response:

This filing proposed four new tiered customer charges, distribution kW billing changes, elimination of the G-62/B-62 rate classes, and adding two new Access Fees.

The Company is currently billing one customer charge per rate class. The proposed tiered customer charges will affect five rate codes in the A-16 and C-06 rate classes. The billing system will need to be modified to accommodate four new customer charges for each of the five rate codes. The proposed customer charges must be programmed to use a specific customer charge amount that is based upon the customer's current kWh usage as well as the previous 11 months of kWh usage.

The distribution kW charge is currently billed on kW usage >10 in the G-02 rate class and kW usage >200 in the G-32 rate class. Programming will be necessary to bill for all kW usage on the nine rate codes that make up these two rate classes. There are three individual charges that make up the distribution kW charge that will need to be modified.

Transitioning from one customer charge to four and the distribution kW parameter changes will need to be carefully managed along with making sure proper handling of cancel/rebill transactions.

The elimination of G-62/B-62 rate class will require all accounts on those rates to be converted to the G-32/B-32 rates along with deactivation of the associated six rate codes to prevent any future accounts from being set up on these rates.

Two new Access Fees will be needed for large stand-alone generating facilities and must be programmed on the three rate codes in the C-06 rate class.

The Company is currently working on detailed requirements for these changes, which provide specification of the changes required in the billing system for programmers. Once these requirements are completed, Information Services (IS) will provide a high level estimate for this project. The Company will provide the estimate for this effort as soon as available.

Prepared by or under the supervision of: Jeffrey P. Martin

Division 1-3

Request:

Please explain why the Company is not proposing changes to rates for energy efficiency or renewable energy programs. Discuss if there is any cost basis for your decision.

Response:

Energy Efficiency Program Charges and charges associated with Long-Term Contracting and Distributed Generation Standard Contracts and net metering are determined annually in separate proceedings before the PUC. Any changes to the design of those charges should be considered in the context of those individual proceedings.

Division 1-4

Request:

Please describe how the Company's current rate proposal incorporates the "benefits of distributed energy resources."

Response:

In this proceeding, the Company has proposed rates for distribution service that are based on fair and equitable cost of service ratemaking principles, with the cost of the distribution system appropriately recovered from the customers in proportion to how they have contributed to the costs in a consistent manner, regardless of whether the customer has on-site generation or not. Any benefits beyond those that are currently inherent in the design of distribution rates should be recognized as part of the compensation provided directly to resources for energy, or energy savings, produced by the resource. If the benefits provided by various forms of distributed energy are valued properly, and provided to distributed generation customers in a transparent manner, customers will be able to make informed decisions regarding implementation of distributed resources. In addition, customers who are required to pay for the benefits provided to distributed energy resources should be able to clearly understand the contribution that each is making to support the renewable energy and energy efficiency programs.

Currently, compensation for net metering, long-term contracting, distributed generation standard contracts, and Renewable Energy Growth Program participants are determined by relevant statutes, Company tariffs, and PUC rules and regulations. The Company is not proposing any changes to the various methods of compensation in this proceeding, but rather will propose any appropriate changes in the dockets that are specific to each program.

In addition, the Company's activities in conjunction with the Office of Energy Resources in implementing a solar generation program in the Tiverton-Little Compton demand response pilot will aid in the determination of actual value and operating characteristics from solar generation. These results, and the results from the Company's affiliate's Solar Phase II pilot in Massachusetts, will help National Grid ascertain the methods to value distributed generation and to propose appropriate payments or credits to those customers who can operate the facilities in a manner to provide those values to the system.

The Company notes that the R.I. Gen. Laws § 39-26.6-24 does not require the Company to propose distribution rates that incorporate the benefits of distributed energy resources, including

Division 1-4, page 2

DG. The law requires that the PUC take into account and balance the benefits of distributed energy resources along with the other factors listed in R.I. Gen. Laws § 39-26.6-24(b).

Division 1-5

Request:

Please explain how the Company arrived at the principal that bill impacts would not exceed +/- five percent for any one customer on an annual basis.

Response:

The Company did not rely on any specific guidance to determine that +/- 5% impact on a customer's total bill is a reasonable bill impact resulting from changes proposed in this proceeding. A revenue neutral rate re-design will necessarily involve bill increases for some customers and decreases for others. The bill impacts will need to be significant enough to accomplish meaningful changes in the design of the distribution charges, but not so significant as to cause severe economic harm to customers. In the Company's opinion, a change of +/- 5% meets those criteria.

Division 1-6

Request:

Please discuss how the Company's rate design proposal advances the integration of load and generation and helps the Company's system evolve towards the "integrated grid" that is discussed in Schedule NG-3. Describe other actions that the Company is undertaking in other states, such as grid modernization in Massachusetts, that are relevant.

Response:

The Company's rate design proposals in this docket advance the integration of load and generation by improving the sustainability of cost recovery fairly and appropriately across all connecting customers. By considering rates based upon size, it presages a move towards demand charges for smaller customers, which will promote innovation as customers use new technology to manage their capacity needs and integrate more efficiently with the electric grid.

The Company's affiliate in Massachusetts has three activities underway that may provide insight into the means to integrate DG and the value from doing so. The first activity is a pilot program in which 16 MWs of solar will be constructed and interconnected on the system in a manner to determine the interaction of solar output with load on the local distribution circuits. The pilot is called the Solar Phase II program. The set-up of the program is to distribute solar facilities on numerous feeders with different characteristics: high load relative to capacity, low load, average loads, etc. The solar construction will be completed with advanced inverters that allow for control of voltage and other necessary electrical capabilities that can assist in providing potential services from the solar generation units. These units will face different directions in order to test the capabilities based upon the direction of the solar panels relative to the location of the sun overhead. This program should provide National Grid with significant information and experience on how to integrate solar generation into the operations of the local distribution system.

The second activity by the Company's affiliates in Massachusetts, Massachusetts Electric Company and Nantucket Electric Company (together, Mass. Electric) is a Smart Energy Solutions Program in the Worcester, Massachusetts area, which is these companies' smart grid pilot program. As part of this program, Mass. Electric has installed over 14,000 smart meters with varying forms of integrated communications devices on residential and small and medium business customers. The pilot also includes the implementation of time-varying rates and critical peak rebates for Basic Service (the equivalent of Standard Offer Service) for customers who choose to participate. The pilot will operate for two years after which Mass. Electric will evaluate the effectiveness of the equipment and rate design with regard to encouraging customers to manage energy their use to reduce overall and peak consumption. Mass. Electric knows of at least three customers who have rooftop solar and are participants in the pilot. In addition to the meters and pricing options provided in the pilot, Mass. Electric is testing forms of Advanced Distribution Automation and Conservation Voltage Reduction. Both of these technologies have the potential to promote additional amounts of distributed generation on the system through their operation and the real-time knowledge of system conditions from the sensors and communication devices on the grid.

Lastly, Mass. Electric filed its Grid Modernization Proposal with the Massachusetts Department of Public Utilities (Department) on August 19, 2015 in compliance with the Department's order in D.P.U. 12-76, Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid (2014). In response to the Department's order, Mass. Electric filed a ten-year Grid Modernization Plan with the Department, including a five-year Short Term Investment Plan. The objectives of the plans, as outlined in the proceeding, are: to reduce the effect of outages; optimize customer demand to reduce system and customer costs; integrate distributed resources; and improve workforce and asset management. The Department's order requires each utility to evaluate the benefits from implementation of Advanced Metering Functionality and its capabilities to provide information to customers and for operation of the electric grid. Mass. Electric's complete filing is available on the Department's website, under docket D.P.U. 15-120:

http://web1.env.state.ma.us/DPU/FileRoom/dockets/bynumber

Mass. Electric's filing describes the potential for certain technologies to benefit the interconnection and integration of distributed resources. This includes metering with real-time capability to allow for more accurate settlement at the ISO-NE and to receive higher prices from the ISO market from hourly readings during the day. Also, the plans include Advanced Distribution Automation, Advanced Distribution Management System and Volt-Var Optimization which, in combination and separately, have the potential to increase the amount of distributed generation that can be interconnected to the system. Also, these technologies have the potential to create markets for services that could be provided by distributed resources.

In New York, on April 25, 2014, the Public Service Commission (PSC) initiated Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision (the REV Proceeding). The REV Proceeding will comprehensively consider how the regulatory paradigm and retail and wholesale market designs either effectuate or impede progress toward achieving the policy objectives underlying New York's system benefit programs and the regulation of electric distribution utilities. Through the REV Proceeding, the PSC seeks to align electric utility practices and the regulatory paradigm with technological advances in information management and power generation and distribution. The proceeding is also intended to develop and institute improvements in system efficiency, provide for more robust customer choice, and allow for a greater penetration of clean generation and energy efficiency technologies. The PSC believes that these developments can only be achieved if barriers to adoption are eliminated and proper regulatory incentives are established. Specifically, the following policy objectives were identified in the REV Proceeding: enhanced customer knowledge and tools that will support effective management of their total energy bill; market animation and leverage of customer contributions; system-wide efficiency; fuel and resource diversity; system reliability and resiliency; and reduction of carbon emissions. At this point, the initiatives, objectives, and intended benefits of the REV Proceeding have not been fully realized, and the Company's New York affiliate, Niagara Mohawk Power Corporation, continues to work with the PSC to review and discuss these items.

Division 1-7

Request:

Please estimate the "cost shifting" from DG customers since the first enrollment in December 2011 under the Distributed Generation Standards Contract Act.

Response:

The 20 projects that have entered into Distributed Generation (DG) Standard Contracts pursuant to R.I. Gen. Laws Chapter 39-26.2 are all stand-alone facilities with no associated on-site load. Therefore, no kWh deliveries have been displaced by the installation of these generating units. However, as described in the Company's joint pre-filed direct testimony on pages 62-63, these facilities impose a cost on the distribution system just as full requirements customers do and should be required to contribute to the recovery of distribution system costs. The Company has proposed an access fee that would be applicable to stand-alone generation facilities participating under one of the Company's renewable energy generation programs, including Long-term Contracting, DG Standard Contracts, Renewable Energy Growth Program, and Net Metering. In Attachment DIV 1-7, an estimate of "cost shift" attributable to DG Standard Contracts projects has been calculated, by multiplying the nameplate capacity of each unit by a capacity availability factor of 40%. (The capacity availability factor of 40% was used for consistency with the Company's response to PUC 1- 18.) Next, the monthly per kW output is multiplied by the proposed $5 per kW access fee to determine the monthly access fee applicable to each unit. Finally, this estimated monthly access fee is multiplied by the number of elapsed months since each DG facility's official commercial operation date to determine the total estimated "cost shift" attributable to each unit.

Division 1-8

Request:

Please explain how the Company's proposed rate design encourages customers "to shift load from high use, peak periods into off-peak periods," as discussed on p. 20 of the pre-filed testimony.

Response:

The discussion on page 20 of the Company's joint pre-filed direct testimony described the Company's vision of the ideal rate design consisting of a customer charge designed to collect (1) customer-related distribution system costs, such as the cost of a meter, billing, and customer service, plus (2) a demand charge that recovers the demand-, or capacity-, related system costs. The demand charge would be assessed on a measurement of customer size, such as maximum connected load or maximum use during a 15-minute interval. It would provide customers an incentive to manage their use during all time periods to avoid having a high demand charge from conducting too many activities at once. Since customers' use is greatest during peak periods, management of demand has the potential to provide an incentive to customers to reschedule or plan some activities for periods of lower demand including off-peak periods. Management of demand will ultimately reduce their billed charges as customers shift load from high use, peak periods into low use, off-peak periods. These actions by customers will result in better utilization of the distribution system.

The proposed designs for residential (Rate A-16) and small commercial and industrial customers (Rate C-06) will not necessarily encourage customers to *shift* load from high use, peak periods into low use, off-peak periods because the proposed design, unlike the ideal design, does not have a direct demand component. Rather, the Company's proposal is intended to encourage customers to reduce, or constrain, overall use during high-use months. Reducing customer use during high use months will result from customer management of demand and, since the ratio of peak to total use would be reduced, accomplish the goal of better system utilization.

Division 1-9

Request:

Please explain if time of use ("TOU") energy rates could approximate the benefits of demand charges that are discussed on p. 21.

Response:

The Company does not believe that time-varying rates (TVR) can effectively approximate the benefits of demand charges. Although it is possible to design time-varying rates for distribution service, distribution rates should be made sustainable over a long period of time. "Sustainable" means the rates provide consistent incentives to customers to improve their own efficiency in electric use and provide adequate revenue to the distribution company while lessening the need for frequent rate cases or rate changes from the under-recovery of revenue targets as part of a distribution company's Revenue Decoupling Mechanism (RDM), if applicable. The Company contends that a demand-based charge for distribution service is most appropriate for meeting those two objectives.

The Company further believes that a demand charge structure for distribution service is more likely to reduce the need for capital investments as the correlation between demand and electricity prices becomes apparent to customers, thereby lowering electricity usage, leading to lower demand and ultimately lower distribution costs through avoided investment. A demand charge focuses the customer on every hour with the goal to reduce their peak, and therefore their demand, across all hours as much as possible. The Company believes that distribution companies should design distribution rates in a manner that is stable and reflective of the fixed cost nature of distribution service.

Customers should be incentivized through rate structures to minimize demand across all hours. By separating the fixed costs for distribution service from the variable costs of electricity reflected in standard offer service rates, the Company can send the appropriate price signal to customers that their energy usage and demand on the distribution system are the key drivers of their electric bills. As customers begin to understand and witness the correlation between energy usage and monthly demand charges, customers should respond by either reducing or shifting energy usage to off-peak hours, thereby reducing their demand on the distribution system during those peak hours and lowering the need for new distribution system capacity. Therefore, the application of TVRs for electric supply can work in tandem with a demand charge construct for the recovery of distribution system costs, and both working together will provide a strong price signal as to the timing of electricity usage, as each will impact customers. However, like rates that include demand charges, TVRs would require metering that is not currently installed at residential and small commercial customer locations. Therefore, the Company has not included TVRs as part of its proposal in this proceeding.

Rates for distribution service should reflect the costs to serve customers, promote sustainability of the rate design, promote more efficient use of the grid by customers, and not create inadvertent results in the Company's RDM approved by the PUC. Over time, distribution rates should begin to move towards a fixed, or demand, charge for all customers (i.e., a fixed charge based on a customer's total size). The use of charges based upon customer size should encourage growth of innovation, more efficient use of the system, and improve customer satisfaction.

The costs of installing and maintaining the distribution system are predominantly fixed costs (e.g., the cost of metering and installing distribution feeders, substations and line drops, property taxes, return on equity, etc.). The rates for distribution service should therefore reflect the cost causative nature of the service and be sustainable over an extended time period. Recovering fixed costs through volumetric charges results in overstated volumetric charges, subjecting a disproportionate amount of a customer's bill to month-to-month fluctuations due to a customer's variation in usage, and as a result creates bills that are more variable and unpredictable. Costs that do not vary with usage should be assessed through a fixed monthly charge, with the cost of the electricity itself (i.e., the commodity) assessed through volumetric charges. This design would result in the customer's overall energy price signal being clear and undistorted by charges not related to their usage.

Additionally, with volumetric distribution charges, customers with lower usage do not pay their fair share of the cost of creating and operating the distribution system. Instead, higher use customers cover the deficit and pay more than their fair share. For example, a customer who consumes their maximum demand during 500 hours in a year will pay much less than a similarly sized customer whose demand is consumed over 5,000 hours in a year. Yet, each of these customers will require the same capacity on the distribution system and therefore the same investment by the distribution company. A rate design that more closely matches fixed and variable costs with fixed and variable charges should reduce this inequity so that all customers will pay an amount which is more representative of their share of the costs of the distribution system.

Further, an appropriate demand charge structure could eventually serve to flatten the load on the distribution system as customers begin to respond to the more apparent fluctuation in variable electricity prices. Flattening the load curve is important to improving asset utilization, which should lead to greater efficiencies as the industry moves towards higher capacity factors. New England has experienced a decline in load factor, or capacity utilization, since the 1990s. ISO-

Division 1-9, page 3

NE predicts the reduction will continue since peak load is forecasted to grow faster and greater capacity will be necessary to serve a given level of kilowatt-hours. Given the fixed cost nature of the industry, this will result in higher investment to provide service and more rate proceedings if the cost of that investment is recovered through volumetric rates. Encouraging customers to manage their demand to avoid paying higher bills will help to promote increased asset utilization and lower the need for new capacity. Demand rates or charges based upon size of customer are one tool the PUC could use to reach the goal of greater efficiency and more choice for customers.

Demand charges could also stimulate innovation in the industry and the development of new industries. For example, a demand charge will encourage customers with rooftop solar to consider battery storage as a means to offset the costs from the demand charge when the sun is not shining or to put into operation a smart inverter to avoid charges for excess voltage requirements. Demand charges could also help owners of electric vehicles to charge their vehicles at times when the demand does not rise above their maximum. This could be in the middle of the night or during certain times of the day when the customer's overall demand on the system is very low. Either way, demand charges focus the customer's effort on not exceeding one number. This will generate greater efficiency in use of the distribution system by customers as they maximize the capacity factor of their own use.

Customers are already accustomed to pricing for other services provided by high fixed cost activities that charge based upon a selected bundle of services, particularly in the telecommunications, internet, and cable TV industries. Demand charges could therefore potentially reduce customer confusion and increase bill transparency as customers learn how to connect the charges shown on their bills with their level of demand. By identifying the value that the distribution system provides in terms of customer demand for the service, customers, particularly customers evaluating solar and battery backup options, can monetize the value of their capacity needs.

Finally, a demand charge is sustainable over time and has a time varying component to it. Customers will understand the need to reduce their maximum demand regardless of when it occurs, which will deliver value directly to the grid in the form of future reduced capacity. This reduces the chance that customers will simply move their use from one high priced period to a low priced period, which will simply move the peak and not reduce it. The industry should consider the alternative perspective, which is a focus on reducing the peak and not simply substituting customers' use of the system with other generation sources or movement of use to other periods.

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

Division 1-9, page 4

The Company recognizes that the rate principles of simplicity, comprehension, and rate moderation may necessitate a long-term approach for implementation of a demand-based charge to those rate classes without them today. It is the Company's opinion that its proposal in this proceeding is the first step in moving towards such a structure.

Division 1-10

Request:

Please compare the cost of meters currently used to the cost of "new, higher-cost metering necessary to measure kW," discussed on p. 22.

Response:

The installed cost for a standard AMR meter used for the small-scale solar projects in the Renewable Energy Growth Program is approximately $108. A meter that can measure demand (kW) costs $225.

Division 1-11

Request:

Please calculate the percentage of demand-related revenue requirements for each rate class that would be collected under the proposed rate designs.

Response:

In Attachment DIV 1-11, the Company has calculated the percentage of non-customer-related revenue requirement that will be recovered from each class through the proposed customer and demand charges. The total customer-related and demand-related revenue requirement for each class was determined as part of the allocated cost of service study performed in the Company's last rate case in Docket No. 4323. The revenue requirement based on equalized rates of return for each rate class is shown on Schedule NG-11 (page 141 of the Company's July 31, 2015 filing in this proceeding). The final rate class revenue allocation approved in Docket No. 4323 was different than the total revenue requirement appearing on Schedule NG-11 because the final allocation included allocation of the low-income subsidy and re-allocation of revenue requirement due to capping, or limiting, the impact of the final allocated revenue requirement for certain rate classes.

For purposes of performing the calculation requested in this request, the demand-related revenue requirement is determined as the revenue requirement remaining after subtracting the customer-related revenue requirement, shown on Schedule NG-11, page 141, lines 7 and 8, from the final, or design, revenue requirement in Schedule NG-10, page 139, line 45. This calculation is shown on lines 1 through 3 of Attachment DIV 1-11. As indicated on line 8 of Attachment DIV 1-11, the following are the percentages of non-customer-related revenue requirement collected through customer charges and demand charges under the proposed rate designs by rate class:

Rate Class	Percentage
A-16 / A-60	14.3%
C-06	16.4%
G-02	88.8%
G-32 / G-62	85.3%

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

The Narragansett Electric Company

Percentage of Demand Related Revenue Requirement Recovered through Customer and/or Demand Charges

		A-16 / A-60 Residential (a)	C-06 Sm. Commercial (b)	G-02 General C&I (c)	B/G-32/B/G-62 Combined Class (d)
1.	Total Revenue Requirement	$133,808,673	$25,523,701	$37,328,115	$41,971,681
2.	Customer Related Revenue Requirement	$39,173,000	$6,725,000	$4,281,000	$2,692,000
3.	Remaining Revenue Requirement	$94,635,673	$18,798,701	$33,047,115	$39,279,681
4.	Rev Req recovered through customer charge	$52,742,963	$9,801,928	$7,531,875	$2,756,945
5.	Rev Req recovered through demand charge	0	0	$26,102,689	$33,422,370
6.	Total Rev Req recovered through cust. and demand charges	$52,742,963	$9,801,928	$33,634,564	$36,179,315
7.	Remaining Rev Req recovered through cust and demand charges	$13,569,963	$3,076,928	$29,353,564	$33,487,315
8.	% Remaining Rev Req recovered through cust and demand charges	14.3%	16.4%	88.8%	85.3%

Line Notes:

Line (1), Column (a):	Schedule NG-12, Page (1): Line (1), Column (c)
Line (1), Column (b):	Schedule NG-12, Page (2): Line (1), Column (c)
Line (1), Column (c):	Schedule NG-12, Page (3): Line (3), Column (c)
Line (1), Column (d):	Schedule NG-12, Page (4): Line (3), Column (c)
Line (2), Column (a):	Schedule NG-11, Page (1): Sum of Lines (7) and (8), Residential x 1000
Line (2), Column (b):	Schedule NG-11, Page (1): Sum of Lines (7) and (8), Small C&I x 1000
Line (2), Column (c):	Schedule NG-11, Page (1): Sum of Lines (7) and (8), General C&I x 1000
Line (2), Column (d):	Schedule NG-11, Page (1): Sum of Lines (7) and (8), 200 kW Demand and 3000 kW Demand (combined) x 1000
Line (3):	Line (1) - Line (2)
Line (4), Column (a):	Schedule NG-12, Page (1): Line (10), Column (f)
Line (4), Column (b):	Schedule NG-12, Page (2): Line (12), Column (f)
Line (4), Column (c):	Schedule NG-12, Page (3): Line (20), Column (e)
Line (4), Column (d):	Schedule NG-12, Page (4): Line (23), Column (f)
Line (5), Column (c):	Schedule NG-12, Page (3): Line (29), Column (e)
Line (5), Column (d):	Schedule NG-12, Page (4): Line (41), Column (f)
Line (6):	Line (4) + Line (5)
Line (7):	Line (6) - Line (2)
Line (8):	Line (7) ÷ Line (3)

Division 1-12

Request:

Please explain by how much—in terms or a range—customers in the medium and large C&I classes would experience changes in costs in excess of +/- 5% (see discussion on p. 24).

Response:

Please see Schedule NG-14 on pages 166-168 of the Company's July 31, 2015 filing, which provides bill impacts for Rates G-02, B/G-32, and B/G-62 based on actual customer billing data for calendar year 2014. This schedule indicates the number of accounts, both in terms of quantity and percentage, which fall within the specified increase/decrease ranges in each rate class.

Division 1-13

Request:

Please explain how the 200 residential and 60 small C&I customers were chosen for the analysis contained in Schedule NG-7.

Response:

The 200 residential and 60 small C&I customers that were chosen for the analysis contained in Schedule NG-7 on pages 131-132 of the Company's July 31, 2015 filing comprise the customers selected for the load research sample for each of those rate classes (Rates A-16 and C-06). The Company has maintained load research sample data for many years following the passage of the Public Utility Regulatory Policies Act in 1978.

Division 1-14

Request:

Please explain if the 12-month periods to determine maximum usage will feature the same or different months for different rate classes and whether there will be differences in the periods for customers within the same rate class.

Response:

The 12-month period to determine maximum usage will be a rolling 12-month period for each customer and will be a customer's prior 11 billing months plus the customer's current billing month.

Division 1-15

Request:

Please explain the timeline for considering advanced or smart metering implementation in Rhode Island and compare this timeline to any efforts by National Grid in other states.

Response:

The Company has not proposed a specific timeframe for implementing advanced metering in Rhode Island. Please see the Company's response to Division 1-6 for a discussion of the activities in Massachusetts and New York related to grid modernization and advanced/smart metering implementation.

Division 1-16

Request:

Please explain whether rates charged for usage could be designed "locally" as is planned for localized credits for distributed generation (see discussion on p .39).

Response:

Rates could be designed locally. This would require a definition of the assets to be included in the local area, and accounting of costs for each area (including plant in service and O&M expense) and determination of the customers served by the facilities. As a general matter, designing geographically specific rates would be difficult to implement. Billing data would require segmentation by rate class and geographically by facilities serving those customers. Although the Company does know gross plant investment in its electric distribution system by location, it does not currently have the granularity of system and loading information away from major substations or at each customer location to accurately calculate localized value. It also does not have other elements of rate base, such as accumulated depreciation and accumulated deferred income taxes, segregated geographically that would allow for a practical and accurate application of a "local" rate design. A change to geographic-based rates and accumulation of billing data would require significant changes in the Company billing and meter data management systems at significant cost.

"Local" rates could lead to customer confusion and dissatisfaction since rates in certain areas would necessarily be higher than in others. Pragmatically, local rates may send incorrect signals to customers regarding use. In areas served by older equipment, rates would be low, which may encourage increased consumption and lead to need for investment. In areas served with newer equipment, rates would be higher which could discourage consumption but this equipment could be able to handle additional load. The solution would be to charge on marginal costs but then you would be charging high prices to customers served by the oldest equipment and low prices to customers served with the newest equipment. Thus, it would be simpler and more equitable to charge for service on average prices and provide localized credits to defer investment where possible. As approved in the Company's System Reliability Plan (i.e., the Tiverton/Little Compton non-wires alternative), the Company is currently providing localized credits, which are calculated based on the possible deferral of an upgrade to the local distribution system, to those customers who participate in all requested load shed calls.

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

Division 1-17

Request:

Please explain why revenue loss associated with kWh deliveries by on-site generation "will continue to grow" after 2021 (discussion on pp. 40-41). Provide any estimates and analysis that was done in support of this statement.

Response:

As shown in Schedules NG-2 and NG-4 on pages 78 and 125, respectively, of the Company's July 31, 2015 filing, once a state or nation begins the promotion of renewable energy, the demand for on-site generation grows dramatically. California and Hawaii present other examples. The Company expects that the DG industry will continue to promote the value of distributed energy resources and customer choice to become a generator of power. For example, the solar industry uses television advertisements, newspaper ads, and direct mail to market roof-top solar to residential customers. The Company believes use of renewable energy is important for our future and simply, through this filing, beginning the process for appropriate cost recovery from all connecting customers to the grid.

More directly, the assumption underlying this statement on pages 40-41 of the Company's joint pre-filed direct testimony is that, although the Renewable Energy (RE) Growth Program solicitations end in 2020, traditional net metering provisions continue to be available to customers who install distributed generation while the RE Growth Program is conducting solicitations as well as beyond 2020 after RE Growth Program solicitations end. As a result, the revenue loss associated with kWh deliveries displaced by on-site generation will continue to grow as new distributed generation will be allowed to be installed and interconnected to the Company's distribution system. Rhode Island is currently faced with the current construct that allows customers with distributed generation to over-generate to the extent that they can zero out their electric bill. These customers are not providing any revenue in support of the continued and necessary operation and maintenance of the distribution system, resulting in all other customers having to pay, through higher distribution rates, this type of customer's properly allocated costs to own, operate, and maintain the distribution system as well as the costs of billing, metering, customer service, and other support functions.

Division 1-18

Request:

Please show how the statement, "Analysis of Company's billing data indicates that less than 15 percent of residential customers have a monthly maximum use" within the range of 0 kWh to 250kWh is consistent with the data shown in Workpaper NG-3.

Response:

The Company prepared a number of frequency analyses, as it developed its proposal filed in this docket, which are shown in Workpaper NG-3. The statement "Analysis of Company's billing data indicates that less than 15 percent of residential customers have a monthly maximum use" within the range of 0 kWh to 250 kWh is supported by the frequency analysis presented on Workpaper NG-3, page 4 of 13 (Bates stamp page 95 of Workpapers book).

Using the first line on page 4 of Workpaper NG-3 as a guide and reading across the table, the table identifies the frequency (count) of customers having their maximum usage in the range of 0 to 12 kWh at 4,655, or 1.0% of customers, having kWh use of 35,631 kWh, or 0.0% of total kWh. Referring to the 14th line on the table for the maximum usage range of 238 to 250 kWh, the frequency (count) of customers in this range is 4,868, or 1.0% of customers, with the cumulative frequency (count of customers) through the range of 0 to 250 kWhs of 65,576, or 14.0% to total customers.

Division 1-19

Request:

Based on your understanding of changes in customer loads over time, how likely are customers to move do different tiers? Indicate whether you analyzed this issue in any quantitative manner.

Response:

A customer may move to a lower tier as a result of decreasing maximum monthly use. For customers whose maximum monthly use is currently close to the lower end of a tier, a move to another tier may be relatively easy to accomplish through turning equipment off, installation of energy saving measures, such as those offered by the Company through its Energy Efficiency Program, or independently replacing inefficient appliances. Customers whose maximum monthly use is not currently close to the lower end of a tier may be able to move to a lower tier by taking similar, but more dramatic steps to reduce monthly use, such as installation of many or large energy efficiency measures.. Although the Company has not performed any analysis, the Company anticipates that those customers who are closest to the tier end points will conserve more aggressively either to remain in their tier or to move to a lower tier. Also, the Company expects that customers can move to lower tiers with aggressive energy efficiency measures. As homes continue to have new, multiple uses for electricity, it is also likely that some customers will not be able to move to a lower tier, and in fact, may move to a higher tier.

An analysis of the Company's residential and small commercial billing data over the past ten years indicates that average use per customer in both classes has been fairly stable even as the number of customers and total system demand have continued to increase during the same period, indicating that, on average, customers have tended to become more efficient over time. This may be due to a combination of improvements over time in the efficiency of major appliances, lighting and other consumer products, and also to a general awareness of customers with regard to the importance of energy efficiency.

Although still in its first full year of operation, the Company expects to gain valuable insight into customer actions and responsiveness to price signals, as well as effective forms of customer communications from its affiliate's, Massachusetts Electric Company, evaluation of its Smart Energy Solutions Program (also known as the Smart Grid pilot) in Worcester, Massachusetts. In this pilot, Massachusetts Electric Company has implemented critical peak pricing and peak time rebates for Basic Service for approximately 15,000 residential and small and medium business customers. The pilot is scheduled to operate for two years.

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

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Division 1-20

Request:

Please indicate what other load research data other than shown in Schedule NG-7 and Workpapers NG-2 and NG-3 were utilized to determine the residential tiers.

Response:

The load research data included in Workpapers NG-2 and Schedule NG-7 were the only load research data utilized to determine the residential tiers.

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

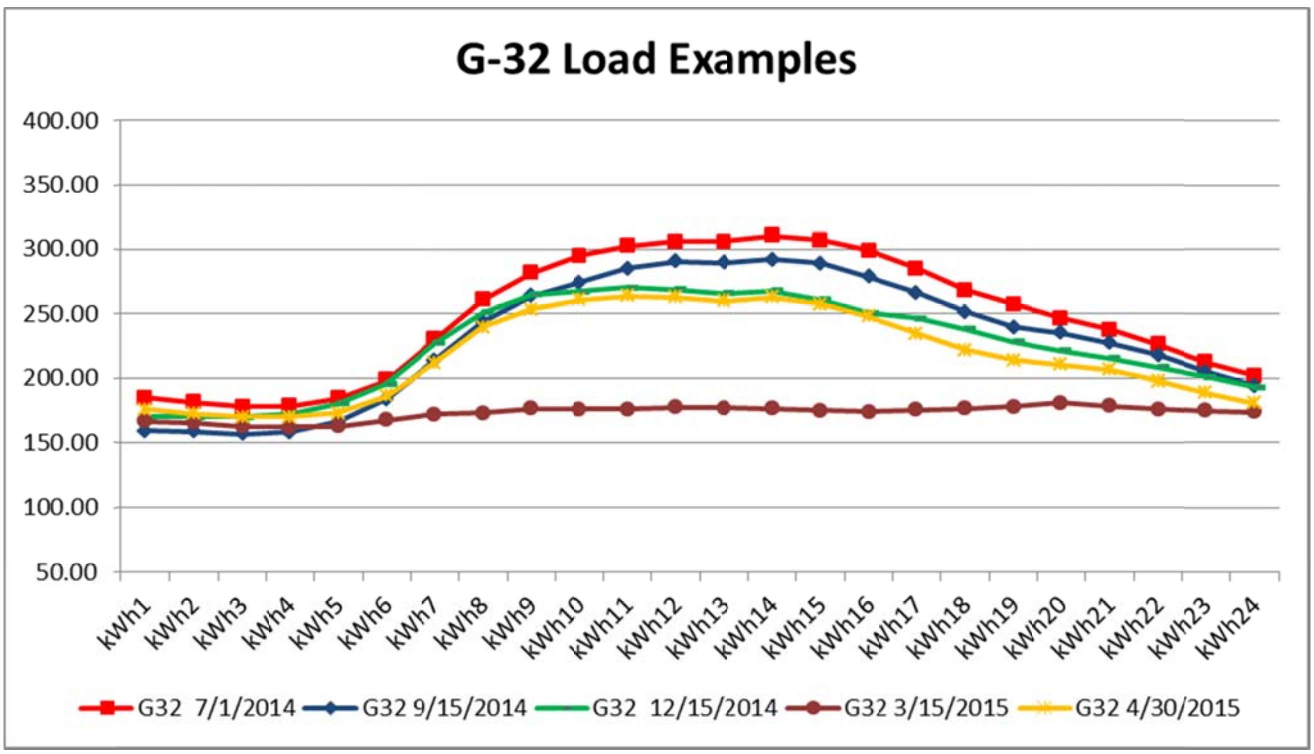
Division 1-21

Request:

Please provide load profile data for Rate G-32 and Rate G-62 customers.

Response:

Load profile data for Rate G-32 and Rate G-62 customers is being provided as Attachment DIV 1-21 in Excel version. As these are hourly data files for a number of years, and could be difficult to interpret, the Company has provided some graphical examples of load profile data for Rate G-32 and G-62 customers for various dates as shown below. The horizontal axis in each example represent the 24 hours of the day. The vertical axis is hourly load (kW).



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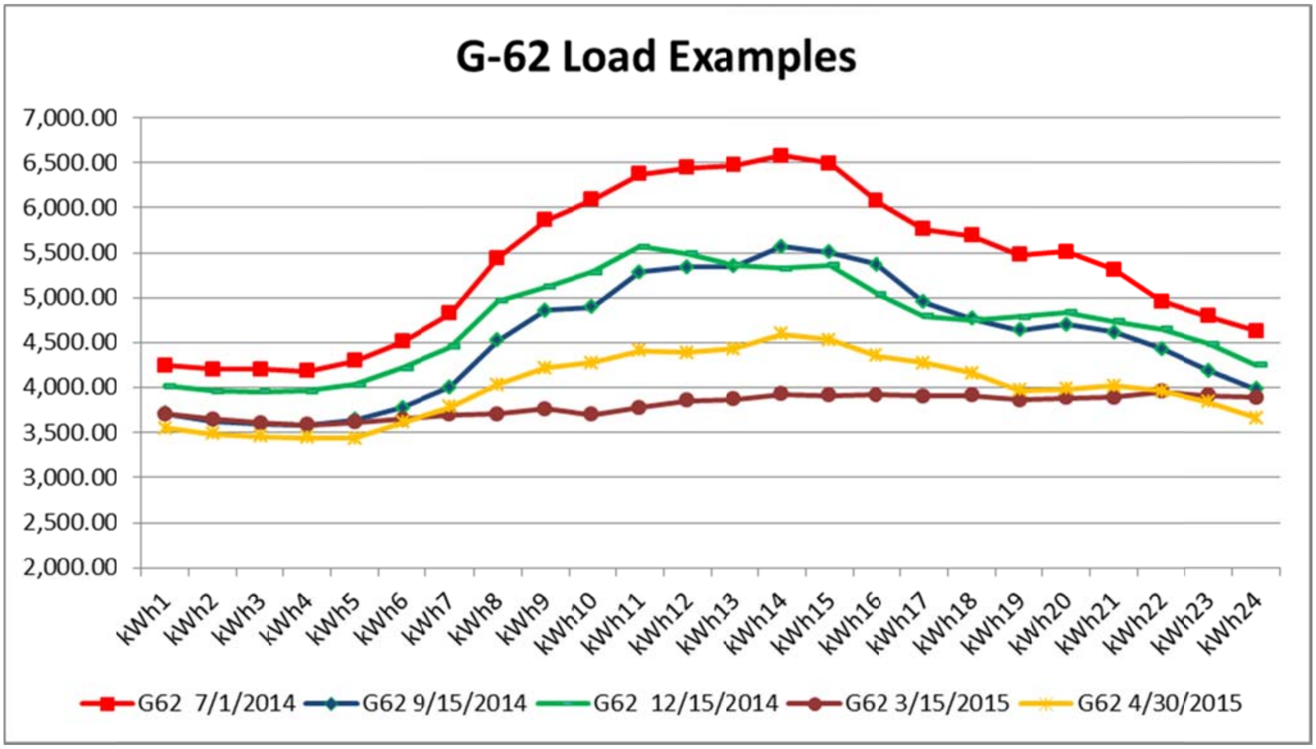

Division 1-22

Request:

Please explain the need for a back-up service rate in light of the rate changes proposed.

Response:

Rate designs that include higher fixed charges and demand charges with ratchet provisions that recover most, or all, of the demand-related revenue requirement may reduce the need for separate back-up service rate provisions. However, the Company did not anticipate proposing the elimination of the current back-up service tariffs as part of this proceeding because the elimination of the rates, and the transfer of the existing back-up service customers to general service rates, could have significant impacts on the customers currently receiving service. The Company does intend to evaluate the need to continue to offer back-up service rates as part of its next general rate case.

The PUC reviewed the use of the Company's current back-up service rates, Rate B-32 (Large Demand) and Rate B-62 (Optional Large Demand) in Docket No. 4232. The rates for the back-up service rate schedules were the result of a settlement among the parties in that proceeding and were designed to appropriately recover costs from customers receiving back-up service. The rates approved in this docket were implemented in 2012. The back-up service tariffs also include certain features, such as a discounted back-up demand charge and a 100% ratchet on generated kW, that provide benefits to customers under certain circumstances. Therefore, elimination of the current back-up provisions could result in significant customer bill impacts to the customers receiving service on those rates. Back-up service rates are not applicable to customers with renewable energy generation.

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

Division 1-23

Request:

Please describe how stand-alone distribution facilities lead to costs of building and operating the distribution system (excluding the cost of interval metering). Provide all workpapers and analyses relied upon to determine the access fees shown on p. 60.

Response:

The majority of the stand-alone distributed generation facilities developed and constructed in Rhode Island to date required upgrades to the electric distribution system that can be grouped in the following categories:

1. Extending a three-phase*[1] line for purposes of connecting the DG facility;
2. Converting a residential single-phase* line to a commercial three-phase line for purposes of connecting DG;
3. Installing protective devices, which are used to protect the electric distribution system from issues related to DG (i.e., automated devices that limit the spread of outages, known as reclosers, and varying types of switches);
4. Using equipment and instrumentation needed for metering customers who take a high voltage service (12.47 kV); and
5. Other re-arrangements of the system based on customer-proposed service locations.

Once the Company constructs the system upgrades, it has to perform ongoing operation and maintenance (O&M) work to repair and maintain the upgrades. Ongoing O&M work consists of activities such as tree trimming, storm-related repairs, resolving DG-related voltage issues, as well as on-going customer service issues for DG customers. In addition, the Company incurs other O&M costs as a result of the system upgrades, such as additional property taxes paid to the municipality for the added plant constructed within the municipality. The annual cost for this ongoing O&M is typically in the range of 5 - 8% of the initial construction costs. The table below shows the cost of the largest ten DG projects as well as an estimate of annual O&M costs.

[1] For terms with an asterisk (*), please see the explanation provided at the end of this response.

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Project	Construction Costs	Nameplate Rating kW (AC)	Fuel Type
1	$482,255	4,500	Wind
2	$1,075,340	3,000	Solar
3	$206,547	2,000	Solar
4	$155,810	2,000	Solar
5	$163,990	1,833	Solar
6	$169,767	1,500	Wind
7	$213,660	1,375	Solar
8	$53,640	850	Solar
9	$149,294	500	Solar
10	$91,531	500	Solar
Totals	$2,761,834	18,058	
Estimated Ongoing Annual O&M Costs at 6% per year	$165,710		

The proposed Access Fees are not derived from the O&M costs, but rather reflect the per unit demand-related revenue requirements, as shown on Schedule NG-11, page 141, line 24, for rates G-32/G-62 (primary) and Rate G-02 (secondary). The per unit charges are further adjusted by approximately 85% (primary) and 75% (secondary) to reflect the relationship between class non-coincidental demand, used in the calculations of the Schedule NG-11, per unit charges, and class maximum demands, used for billing purposes. No other schedules or workpapers were used in the development of the proposed Access Fees.

The term "single-phase" is used to reference a characteristic of electrical service. Utilities in the U.S. distribute electricity using three-phase service (or three wires, a neutral, and a ground). Utilities will use one wire (or a single-phase) to serve customers that do not need a three-phase service. Customers with large electrical loads (i.e., retail box stores, larger restaurants) require a three-phase service; residential customers only require a single-phase service. Similar to large, electric loads that require this type of service, larger DG projects (>15 kWs) are required to connect to a three-phase system to prevent load and voltage imbalances. Therefore, if a

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customer is proposing a 100 kW project, the Company must have three-phase service available to interconnect that customer's project to the Company's distribution system.[2]

[2] See the Company's responses to data requests COMM 6-5 and COMM 6-8 in Docket No. 4483.

Division 1-24

Request:

Please indicate whether the company has provided an estimate of the costs of this group of customers and how these costs will be accounted for in the Company's next rate case. Will collection of these costs result in "over-collection" of costs from a cost causation perspective?

Response:

The Company has assumed this group of customers (i.e., stand-alone distributed generators) causes similar costs on the system as traditional load customers. These customers need the distribution system to deliver their power someplace, whether it is the wholesale market or to another customer of a utility. The system will need to be upgraded and maintained to meet the stand-alone generators' needs as well as the needs of traditional customers. Thus, the Company has not provided an estimate of the costs associated with stand-alone distributed generation facilities since the Company has developed rates based upon cost-of-service based rates for customers of similar size. In the next rate case, the Company will account for the use of the distribution system by stand-alone customers in a manner consistent with full-requirements customers in the development of appropriate class allocation factors. Collection of these costs will not result in an over-collection of costs since the Company will design rates to appropriately recover each class's revenue requirement in a manner consistent with the way costs are allocated.

Division 1-25

Request:

Please describe the "need" from the Company's perspective and from the perspective of customers (DG and non-DG) given the presence of Revenue Decoupling Mechanism ("RDM").

Response:

The Company assumes that the question is asking the Company to describe the need for shifting costs recovered through per kWh charges to recovery through customer and demand charges. The existence of the Revenue Decoupling Mechanism (RDM) ensures that the Company fully realizes its annual target revenue regardless of the structure of the rates applicable to each rate class. The rates proposed by the Company in this proceeding may result in less volatility in the annual reconciliation balance, but will have no effect on the overall revenue that the Company is currently allowed to realize through the RDM.

The RDM does, however, have an effect on individual customer bills. To the extent that a customer installs distributed generation (DG), and thereby reduces his/her contribution to the annual revenue target, that revenue reduction will contribute to the under-recovery of the annual target revenue, and that under-recovery will be recovered during the subsequent 12 months from all other customers through a per kWh charge. Therefore, customers who install DG are able to shift costs to non-DG customers through the operation of the RDM. Increasing the non-kWh charge component of the bill will ensure that customers who install DG will make a more meaningful contribution to the annual target revenue and will reduce the amount of any under-recovery of the annual target revenue shifted to non-DG customers.

Thus, reliance upon RDM is a non-sustainable approach to ensure the distribution system is available for all connecting customers, whether with or without DG, at a reasonable cost, since relying on RDM will continually raise rates and not reflect rates based on appropriate cost-causation. In the end, this will result in customers spending more than is necessary to install renewable generation at their locations and with non-DG customers paying costs for which they are not responsible.