Liberty Utilities

**STATE OF NEW HAMPSHIRE**
**BEFORE THE**
**PUBLIC UTILITIES COMMISSION**

Docket No. DE 19-064

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

**DIRECT TESTIMONY**

**OF**

**GREGG H. THERRIEN**

April 30, 2019

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# ATTACHMENTS

**I. INTRODUCTION**

**Q. Please state your name, address, and position.**

A. My name is Gregg H. Therrien. I am an Assistant Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts. My professional qualifications and experience have been provided in Attachment GHT-1 to this testimony.

**Q. Have you testified previously before the New Hampshire Public Utilities Commission ("NHPUC" or the "Commission")?**

A. Yes, I have. I previously provided written and oral testimony in Docket No. DG 17-048, Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities' ("EnergyNorth") distribution service rate case.

**Q. What is your responsibility in this proceeding?**

A. In this proceeding, I am responsible for designing the Revenue Decoupling Mechanism for Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Granite State" or "the Company").

**II. SCOPE OF DECOUPLING TESTIMONY**

**Q. Please summarize the scope of your testimony concerning the Company's proposed Revenue Decoupling Mechanism ("RDM").**

A. In this testimony, I will:

1) Provide general background on RDMs, why they are a necessary part of a comprehensive energy efficiency program, and why traditional ratemaking is insufficient support for utility energy efficiency advocacy;
2) Provide the results of our research on RDMs that have been implemented by electric distribution companies throughout the U.S.;
3) Describe my understanding of the energy efficiency settlement agreement in Docket No. DE 15-137, and how it recognizes the need to harmonize increased energy efficiency spending with appropriate changes in ratemaking;
4) Describe and explain the Company's proposed RDM, which will allow Granite State to continue to be a forceful and active advocate for energy conservation efforts, without harming its ability to earn a reasonable return; and
5) Discuss how decoupling can complement recent electric industry rate design initiatives that support energy efficiency, renewable distributed generation ("DG"), battery storage technology, and electric vehicle ("EV") charging while protecting customers and the Company from unintended rate recovery consequences.

**Q. Please summarize your conclusions and recommendations.**

A. My conclusions and recommendations are as follows:

- In recent years, there has been a heightened focus on energy conservation efforts and policies that encourage conservation.[1] This interest in energy conservation

[1] Heightened focus in New Hampshire on energy conservation efforts and enabling policies to encourage conservation are demonstrated in the following reports: (a) New Hampshire Independent Study of Energy Policy Issues (September 2011), prepared for the New Hampshire Public Utilities Commission by Vermont Energy Investment Corporation;

has been attributed to environmental considerations and cost considerations. Cost considerations include both customers participating in utility-sponsored programs and the utility's cost to serve.

- Granite State proposes to implement a new rate mechanism that will "decouple" the traditional connections between the volume of kWh that Granite State delivers to its customers and its revenues and earnings.
- The decoupling mechanism that the Company is proposing:
  - Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;
  - Will comport with the State of New Hampshire's vision in its 2018 State Energy Strategy, which recognized that "Energy efficiency (EE) is often the cheapest and cleanest energy resource. Investing in efficiency boosts the state's economy by creating jobs and reducing energy costs for consumers and businesses. New Hampshire should prioritize capturing more efficiency in all sectors, including buildings, manufacturing, and transportation"; [2]
  - Will realize the vision crafted by the Settling Parties in the Energy Efficiency Resource Standards ("EERS") docket[3] by producing equitable ratemaking

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(b) Increasing Energy Efficiency in New Hampshire: Realizing Our Potential, (November 2013), prepared for the New Hampshire Office of Energy and Planning by the Vermont Energy Investment Corporation; (c) New Hampshire 10-Year State Energy Strategy (September 2014), published by New Hampshire Office of Energy & Planning; and most recently (d) the Energy Efficiency Resource Standard Settlement Agreement (the "Settlement Agreement"), dated April 27, 2016, as approved in the NHPUC Order No. 25,932 in Docket No. DG 15-137 (Aug. 2, 2016).

[2] New Hampshire 10-Year State Energy Strategy published by the New Hampshire Office of Strategic Initiatives April 2018. Goal 4: Maximize cost-effective energy savings, page 14.

[3] The "Settling Parties" as defined in the Settlement Agreement dated April 27, 2016, which was approved in Docket No. DG 15-137, include: Commission Staff, Liberty Utilities (Granite State Electric) Corp.; Unitil Energy Systems, Inc.; Public Service Company of New Hampshire dba / Eversource Energy; the New Hampshire Electric

beyond the interim Lost Revenue Adjustment Mechanism ("LRAM") that fully supports the goals and enables full acceptance of the energy savings initiatives envisioned in the Settlement Agreement;

- Will fix a flaw in the traditional ratemaking methodology that does not allow utilities the opportunity to earn a reasonable return when customer usage is declining; and
- Will enable the Company and New Hampshire stakeholders to implement innovative rate design in support of renewable DG, EV, and other emerging technologies and electricity applications without the risk of over- or under-recovery of allowed revenue requirements.

## III. OVERVIEW OF DECOUPLING

### A. Introduction

**Q. Please describe a revenue decoupling mechanism.**

A. In general terms, an RDM breaks the link between the quantities that a utility delivers to its customers and that utility's revenues. By eliminating the link between customer consumption and Company earnings, decoupling removes the disincentive for utilities to promote conservation and energy efficiency programs. Companies that have implemented decoupling are no longer caught between promoting conservation (that reduce sales) and growing revenues (by increasing sales). Breaking the link between

Cooperative, Inc. Liberty Utilities (EnergyNorth Natural Gas) Corp.; Northern Utilities, Inc.; the Office of the Consumer Advocate; the Department of Environmental Services; the Office of Energy and Planning (OEP); New Hampshire Community Action Association; The Way home; the Conservation Law foundation; The Jordan Institute; Acadia Center; the New Hampshire Sustainable Energy Association; the New England Clean Energy Council; the NH Community Development finance Authority; and TRC Energy Services.

utility sales and revenues is the best way to promote conservation activities fully and freely. Other mechanisms that only compensate the utility for the costs of conservation programs, such as an LRAM, fall short.

**Q. Why is an LRAM insufficient in promoting conservation programs?**

A. Mechanisms such as the recently approved LRAM in New Hampshire only compensate for energy efficiency measures installed as a result of utility programs, and alone do not promote conservation behaviors. The American Council for an Energy Efficient Economy ("ACEEE"), a nonprofit 501(c)(3) organization whose stated mission is to "act as a catalyst to advance energy efficiency policies, programs, technologies, investments, and behaviors,"[4] states:

> An LRAM alone will not fully incentivize efficiency nor remove the throughput incentive. While the lost revenue adjustment can help make a utility whole by compensating it for reduced energy sales associated with efficiency programs, it will do little to encourage investment in energy efficiency unless combined with other policy levers. In fact, our analyses indicate that having an LRAM policy itself is not currently associated with higher levels of energy efficiency effort (program spending) or achievement (energy savings) than are found in states without an LRAM policy. Nor does LRAM reduce a utility's motivation to increase sales (although some states do have safety nets in place). To fully remove the throughput incentive, decoupling should be considered.[5]

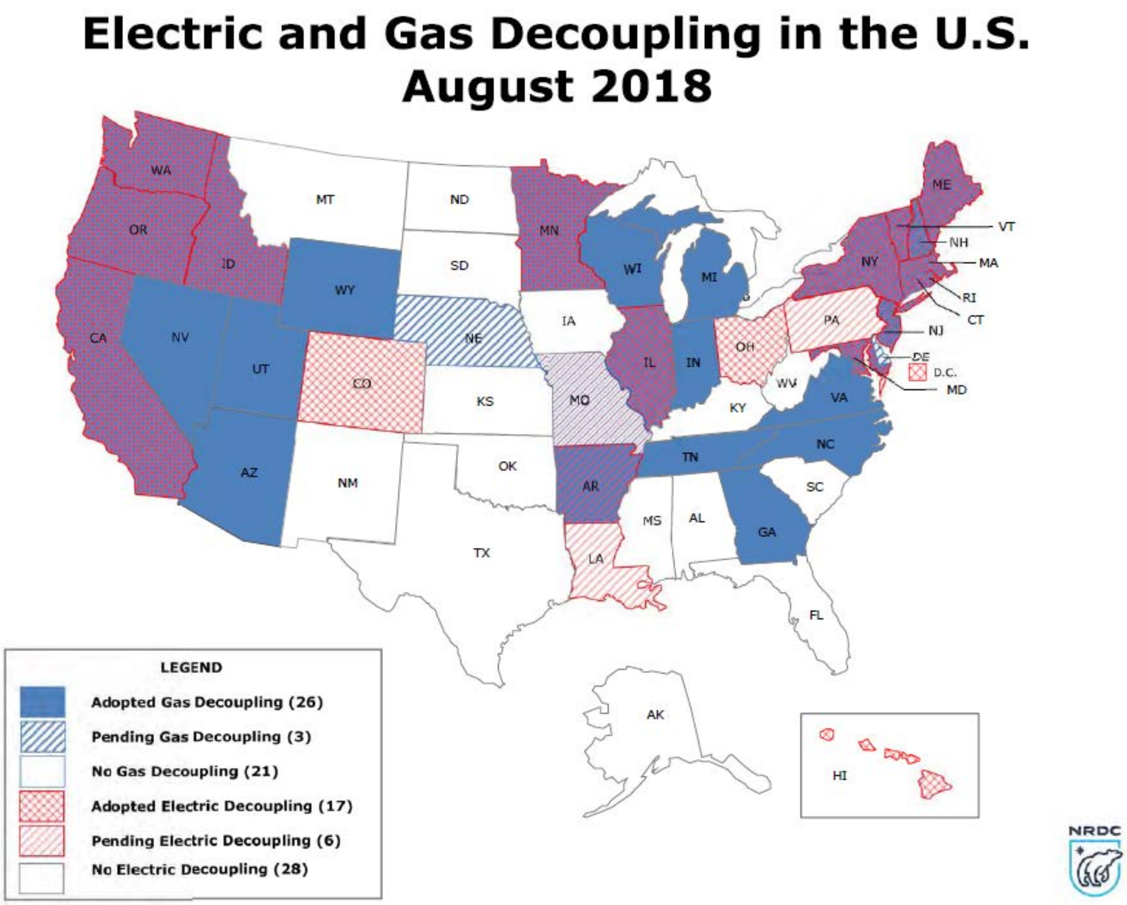
4 *See* http://aceee.org/about-us.
5 "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms", June 2015, ACEEE Report U1503.

**Q. Is decoupling a new concept for electric and gas utilities?**

A. No, decoupling has been utilized by electric and gas utilities for several decades.[6] Regardless of end use commodity (i.e., gas, electric, or water), decoupling is a well-known and embraced means of encouraging energy conservation across the country. This is demonstrated by the following:

[6] "California has the most experience with decoupling, having operated such a mechanism in the electricity sector from 1981 through 1996, and just recently restarting the system in the State." Decoupling For Electric & Gas Utilities: Frequently Asked Questions (FAQ), published by the National Association of Regulatory Commissioners ("NARUC") Grants & Research Department, September 2007.

**Chart 1: Revenue Decoupling Mechanism Adoption in the U.S.[7]**




| | 2013 | | 2018 | |
|---|---|---|---|---|
| | Utilities | States | Utilities | States |
| Gas | 49 | 20 | 64 | 26 |
| Electric | 24 | 14 | 41 | 17 |
| Total | 73 | 25 | 105 | 32 |

Note: NH's decoupling status is no longer "pending" as the Commission recently approved a decoupling mechanism for EnergyNorth.

**Q. How does a decoupling mechanism work?**

A. RDMs generally adjust rates on a periodic basis (e.g. annually or seasonally) to "make up" the difference between a target revenue per customer, which would have been set in

[7] National Defense Resource Council, "Gas and Electric Decoupling", fact sheet dated August 24, 2018.

the most recent rate case, and actual revenue per customer. RDMs are symmetrical; the calculation can result in either a charge or credit depending on the actual revenue per customer. A rate adjustment credit will be included in customers' bills in a future period when actual revenue per customer is greater than the target revenue per customer in a recently-completed period. Conversely, a rate adjustment charge will be included in customers' bills when actual revenue per customer is less than the target revenue per customer.

**Q. Why do utilities need decoupling?**

A. Utilities are becoming increasingly responsible for managing and actively promoting customer conservation through the development and implementation of robust energy efficiency programs, as is the case in New Hampshire with the utility administered CORE Energy Efficiency Programs and now the EERS Programs. All else being equal, these programs will result in lower use per customer ("UPC"). For example, utility customers have become increasingly aware of energy use and have invested in energy efficiency measures with their own dollars. For example, "big box" home improvement retailers routinely conduct workshops on energy efficiency measures that homeowners can easily undertake on their own. Appliance efficiency improvements and stricter building code requirements result in higher overall energy efficiencies when customer equipment and existing building stock are replaced. Lastly, other external factors such as economic factors, demographics, and weather trends can contribute to changes in consumption. While reduced energy usage is good for individual consumers and society as a whole, it does have a negative impact on a utility's ability to earn its allowed rate of return under traditional ratemaking. Volumetrically priced delivery rates are designed to collect the Company's revenue requirements under normal weather and a representative test year. If actual throughput declines once rates are set, the utility will under-recover its revenue requirement, which negatively impacts the utility's earnings until rates are reset.

**Q. Can decoupling complement recent developments and technologies in electric utility service?**

A. Yes. Decoupling, as stated above, severs the relationship between utility sales and revenues. Although primarily adopted to facilitate energy efficiency, decoupling can also facilitate changes in rate design aimed at enabling better cost causation through "opt-in" rates[8]. Decoupling can also play a role in minimizing the financial impacts of widespread customer-owned DG (e.g., photovoltaic solar panels, or "PV") adoption. Alternative rate designs such as time of use ("TOU") rates and critical peak pricing can be explored without the risk of the utility either over-collecting its allowed revenue requirement (if identified customers choose not to participate in new rates that may save them money), or under-collecting (if, for example, solar PV adoption rates increase at a greater than anticipated pace).

**Q. Please elaborate on the utility earnings dilemma.**

A. The Company's financial performance, all else being equal, is negatively affected by declining use per customer ("UPC"). Decoupling is an appropriate and increasingly common component of a well-designed and implemented demand-side management

[8] "Opt-in" rates are voluntary rates that customers may be eligible to select, such as time of use rates.

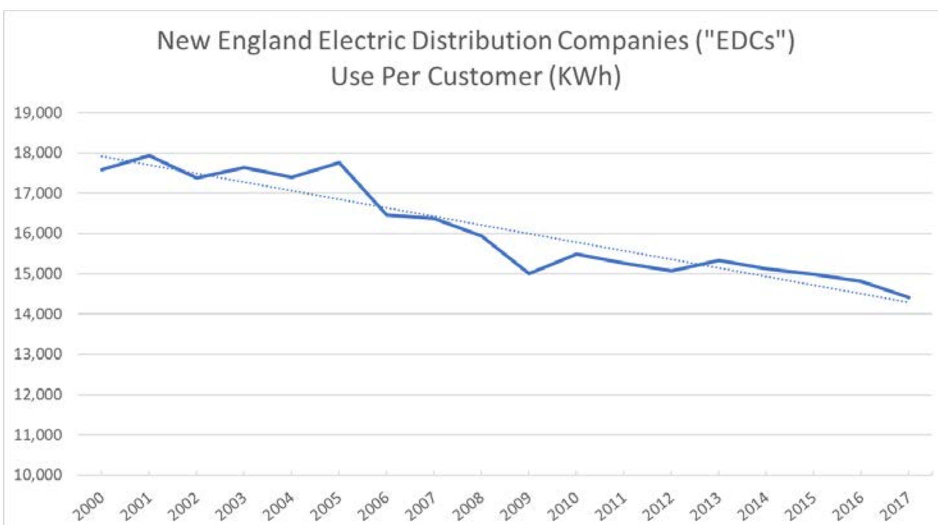
("DSM") program. Decoupling is appropriate whenever a utility's rates are designed such that a decrease in sales volumes adversely affects the ability of the utility to earn a reasonable return on investment. According to the Regulatory Assistance Project ("RAP"):

> Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers.[9]

**Q. Is there evidence of declining electric UPC in New England?**

A. Yes. UPC has been declining over the past two decades, resulting in an 18% decrease from 2000 to 2017:

**Chart 2: New England Annual Electricity Use Per Customer**

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[9] "Revenue Regulation and Decoupling: A Guide to Theory and Application", November 2016, page 26.

**Q. Why should policy-makers and customers support decoupling?**

A. As discussed above, decoupling unlocks the utility's ability to enthusiastically support energy efficiency policy goals. Over time, decoupling mechanisms provide rate stability that results from the mechanism's symmetrical design.[10] Decoupling can protect customers from a utility recovering excess revenues that may result from warmer than normal weather or from favorable economic conditions. Decoupling also protects customers and the Company from over- or under-collection of revenues from customer-owned DG and rate design changes. The Commission recognized these benefits when approving the EERS settlement, which explicitly includes decoupling as a component to the solutions needed to achieve the important policy goals contained within.

**Q. Do other EDCs in New England have decoupling?**

A. Yes. Nine of fourteen New England EDCs have an RDM:

**Table 1: New England EDC Decoupling Mechanisms**

| Company Name | State | Decoupling? | Year Implemented | Comments |
|---|---|---|---|---|
| Central Maine Power Company | ME | Y | 2013 | Docket No. 2013-168 |
| Connecticut Light and Power Company | CT | Y | 2014 | Docket No. 14-05-06 |
| Emera Maine | ME | N | | Pending Non-Wires Alternatives proceeding outcome, MPSC Docket No. 2018-00171 |
| Fitchburg Gas and Electric Light Company | MA | Y | 2011 | National Grid RI |
| Green Mountain Power Corporation | VT | N | | |

10 RAP also recognized this, stating, "Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable." "Revenue Regulation and Decoupling: A Guide to Theory and Application," November 2016, page 26.

| Company Name | State | Decoupling? | Year Implemented | Comments |
|---|---|---|---|---|
| Massachusetts Electric Company | MA | Y | 2009 | Docket 09-39 |
| Nantucket Electric Co. | MA | Y | 2009 | Docket 09-39 |
| Narragansett Electric Company | RI | Y | 2012 | Docket No. 4206 |
| NSTAR Electric Company | MA | Y | 2018 | Docket No.17-05 |
| Public Service Company of New Hampshire | NH | N | | |
| United Illuminating Company | CT | Y | 2017 | Docket 16-06-04 |
| Unitil Energy Systems, Inc. | NH | N | | |
| Western Massachusetts Electric Company | MA | Y | 2017 | Docket No.17-05 |

**Q. Is this the first decoupling mechanism proposal in New Hampshire?**

A. No. The NHPUC approved a decoupling mechanism for Granite State's New Hampshire natural gas utility affiliate, EnergyNorth in its last rate case in Docket No. DG 17-048. EnergyNorth's RDM was successfully implemented on November 1, 2018.[11]

**Q. Is Granite State's RDM proposal here identical to that of EnergyNorth?**

A. No, but it is very similar. EnergyNorth's RDM includes a real-time weather normalization component that is not included in the Granite State RDM proposal. The rationale for this difference is explained in more detail in Section V below. Otherwise, the Granite State proposal is essentially the same as the EnergyNorth mechanism.

[11] EnergyNorth previously sought decoupling in its two prior rate cases, Docket Nos. DG 14-180 and DG 10-017, but those proposals were ultimately not presented to the Commission for approval. Order No. 25,797 (June 26, 2015), and Order No. 25,202 (Mar. 10, 2011).

### B. Support for Decoupling: Energy Efficiency Programs

**Q. Why is decoupling important for regulated utilities that offer energy efficiency programs?**

A. The ACEEE best summarized the importance of decoupling for regulated utilities in its June 2014 Policy Brief titled, "Utility Initiatives: Alternative Business Models and Incentive Mechanisms," where it stated that:

> Under traditional rate-of-return regulation, utilities have an economic disincentive to provide programs to help their customers be more energy efficient. Because a utility's earnings are based on the total amount of capital invested and the amount of electricity sold, increased energy sales generally increase utility profits. Experience suggests that enacting regulatory reforms such as decoupling … help overcome those inherent disincentives regarding energy efficiency.

Further, in its June 2015 Report titled, "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms,"[12] ACEEE stated:

> Creating a regulatory environment that incentivizes utilities to invest in efficiency is critical for programs to be successful, impactful, and long lasting. Doing so requires a mix of policy tools. In addition to energy efficiency targets, utilities need a business model that aligns their financial interests with energy efficiency, including program cost recovery, performance incentives that encourage utilities to achieve high levels of savings, and some policy mechanism to neutralize the throughput incentive. It is our opinion that decoupling is the best third leg of this stool.

These ACEEE policy excerpts clearly show the need for, and evolution of, utility ratemaking that supports energy efficiency goals.

[12] Report U1503.

### C. <u>Support for Decoupling: Ratemaking</u>

**Q. Please describe and explain the structure of decoupling mechanisms.**

A. RDMs calculate a surplus or shortfall between actual and allowed revenues. There are two common RDM structures: revenue per customer ("RPC") RDMs and Total Revenue RDMs. The primary differences between these two structures are the revenue "true up" calculation and the treatment of new customers. The RPC RDM revenue true up determines the revenue shortfall or surplus by (a) calculating the difference between the target RPC and actual current period RPC by customer group or rate class, and (b) multiplying the difference per customer ("RDM per Customer Adjustment") by the current period number of customers. The effect of an RPC RDM is that the sum of actual rate class/rate group revenues per customer plus the RPC RDM per customer adjustment will always equal the target RPC, and total actual revenues will change in direct proportion to the change in the number of customers between the test year and current period. New customer revenues are therefore preserved to fund new customer investment made by the utility.

The total revenue true up determines the revenue shortfall or surplus by calculating the difference between the target revenues and actual current period revenues by customer group or rate class. The effect of a Total Revenue RDM is that the sum of actual rate class/rate group revenues, plus the Total Revenue RDM true up for each rate class/rate group, will always equal the revenue target and total actual revenues will not change until the utility's next rate case. There is no inherent recognition of new customer additions or losses in this approach.

**Q. Of these two types of RDM, which is the best fit for electric distribution companies?**

A. The application of an RPC RDM best suits utilities that add new customers to their system. Adding new customers to the system involves incremental capital investment, which requires that the revenues from these new customers be necessarily retained by the Company to fund this new investment. Therefore, RPC RDMs are superior to Total Revenue RDMs for those utilities with a growing customer base, as new customer revenues are retained (at the system average RPC) to help cover the cost of the corresponding new investment. If a Total Revenue RDM is employed instead, the incentive to add new customers is significantly diminished, as total revenues will remain unchanged while rate base grows. A Total Revenue RDM is best employed for a utility that is losing customers, such as an electric utility with declining customer counts and/or customers selectively leaving the grid (e.g., full-use rooftop solar with battery, industrial-sized DG, etc.).

**Q. Given the differences between an RPC and Total Revenue RDM, which is best for Granite State?**

A. Granite State is proposing an RPC RDM because it anticipates adding a significant number of new customers to its distribution system.[13] With these added customers will come added capital expenditures necessary to connect them to the distribution system. The proposed RPC RDM will provide incremental revenues (at the class average) to help

[13] Granite State anticipates significant growth in residential housing due to the construction of the Tuscan Village in Salem, New Hampshire, located at the former Rockingham Race Track. Granite State's customer counts have grown more rapidly in 2018 than historically for this area. Granite State will continue to experience additional customer growth into 2021 as result of the Tuscan Village Development.

Granite State cover the revenue requirements associated with these incremental investments. If a Total Revenue RDM is approved instead, Granite State would not be compensated for these incremental investments between rate cases, creating a potential significant regulatory lag. All else being equal, an RPC RDM helps utilities stay out of rate cases when customer counts grow.

**Q. Will Granite State's RDM include a weather normalization adjustment?**

A. No. The EnergyNorth RDM included a weather-related adjustment because gas sales and gas commodity prices are more heavily influenced by fluctuations in weather. This issue is less significant in the case of electric sales and generation charges. Furthermore, the absence of a weather-related adjustment simplifies the overall RDM calculation.

**Q. Does decoupling guarantee utility earnings?**

A. No, it does not. The proposed RDM trues up revenues to the amount allowed on a per-customer basis. The utility remains at risk for managing its expenses commensurate with the level set for the test year base rates. This means the utility must manage its capital expenditure programs, its operations (e.g., salaries and wages, benefits, overtime, maintenance programs, uncollectibles, outside services, etc.), and pay taxes (including property taxes that are adjusted annually by most municipalities).

### D. Electric Utility Experience with Decoupling

#### 1. Decoupling in the U.S.

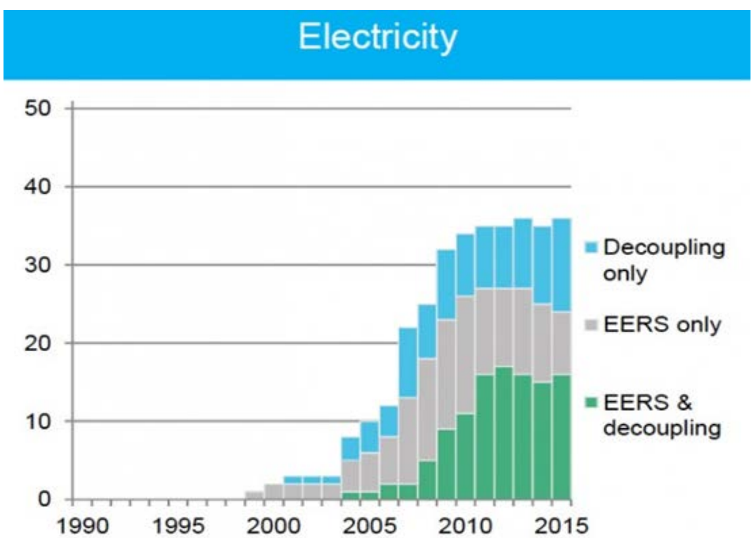
**Q. Please summarize electric decoupling in the U.S.**

A. As of August 2018, at least 23 states have electric utilities with approved RDMs or have proceedings where decoupling had been initiated.

**Q. Do electric distribution companies with RDMs also have state EERS requirements?**

A. Yes. The following chart shows the adoption rate of both EERS and decoupling for electric distribution companies:[14]

**Chart 3: Decoupling and EERS**




As this chart shows, the rate of adoption of both EERS and decoupling has increased dramatically over the past decade.

[14] "U.S. Economic growth Decouples from Both Energy and Electricity Use", ThinkProgress.com, Joe Romm, February 4, 2016.

**Q. Please summarize electric decoupling in New England.**

A. Decoupling has become common practice in most New England states. The Massachusetts Department of Public Utilities ("MA DPU") initiated a generic proceeding to standardize all RDMs for distribution utilities. In DPU 07-50-A, the MA DPU directed each electric and gas distribution company to propose a full RDM in a future rate proceeding. The Department explained the benefits of decoupling as the "elimination of financial barriers to the full engagement and participation by the Commonwealth's investor-owned distribution companies in demand-reducing efforts."[15]

The MA DPU previously approved RPC decoupling mechanisms for WMECo (17-05), Bay State Gas (09-30) National Grid (gas, 10-55), and approved a total revenue approach for National Grid (electric, 09-39).

Connecticut adopted decoupling as a product of a larger energy strategy promoted by the Governor and ultimately codified into legislation. *See* Public Act 13-298, *An Act Concerning Implementation of Connecticut's Comprehensive Energy Strategy and Various Revisions to the Energy Statutes*, promulgated July 8, 2013. Section 16-19tt of the general statutes was modified by this Act to require decoupling for all electric and gas utilities:

> In any rate case initiated on or after the effective date of this section or in a pending rate case for which a final decision has not been issued prior to the effective date of this section, the Public Utilities Regulatory Authority shall order the state's gas and electric distribution companies to decouple distribution revenues from the volume of natural gas and electricity sales. For electric distribution companies,

[15] MA DPU 17-05 p. 219.

> the decoupling mechanism shall be the adjustment of actual distribution revenues to allowed distribution revenues. For gas distribution companies, the decoupling mechanism shall be a mechanism that does not remove the incentive to support the expansion of natural gas use pursuant to the 2013 Comprehensive Energy Strategy, such as a mechanism that decouples distribution revenue based on a use-per-customer basis. In making its determination on this matter, the authority shall consider the impact of decoupling on the gas or electric distribution company's return on equity and make any necessary adjustments thereto.[16]

To date, the approved decoupling structure for both electric and gas companies in Connecticut is based on total revenues. Although this form of decoupling can discourage growth, it was deemed the simplest for consumers to understand and for the companies and regulators to administer (and a requirement of the Act for electric companies). Further, gas companies in Connecticut have a separate ratemaking mechanism to recover capital expenditure revenue requirements from new customer additions as part of the state's Natural Gas Expansion Plan.

In Maine, effective September 1, 2014, the Commission approved a settlement in Docket No. 2013-168 that applied an RDM to Central Maine Power distribution revenues and applied the RDM to two rate classes. Emera Maine, the other electric distribution company in Maine, is exploring proposing decoupling in its next rate case, part of its plan to assist in implementing non-wires alternatives ("NWA") rate design measures.[17]

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[16] Public Act 13-298 page 13.

[17] On June 22, 2018 in docket no. 2016-049, the Maine electric distribution companies, Central Maine Power and Emera Maine, filed a joint NWA proposal that included a RPC decoupling mechanism.

The Rhode Island General Assembly passed the Decoupling Act during the 2010 legislative session, which required electric and gas revenues of Narragansett Electric Company to be fully decoupled from sales.[18] In May 2012, the Rhode Island Public Utilities Commission approved Narragansett Electric's proposed RDM.[19]

**Q. Has decoupling been adopted in New Hampshire?**

A. Yes. The Commission approved a revenue per customer mechanism for EnergyNorth. Although the originally proposed mechanism was a full RDM, a bandwidth was proposed to mitigate large single year adjustments. The bandwidth was 5% of total revenues. Any RDM adjustment above this upper limit would be deferred, with carrying charges, to the subsequent decoupling period.

The revised RDM that was proposed through an EnergyNorth – Office of the Consumer Advocate settlement was based on a revenue per customer approach. The Commission described the decoupling plan as follows:

> … as well as a decoupling plan under which revenue per customer targets would be established for each rate class. Each month, and again at the end of each year, rates would be adjusted up or down to allow the Company to collect the established revenue per customer targets. The monthly adjustments would account for changes in weather. In months when temperatures were colder than normal, customers would receive a credit on their bill to return the increased revenues that Liberty would have collected due to higher usage during the colder than normal temperatures. During warmer months, customers would pay a charge to

[18] R.I.G.L. §39-1-27.7.1(a). The Act's decoupling mandate applies to an electric distribution company defined as "a company engaging in the distribution of electricity or owning, operating, or controlling distribution facilities and shall be a public utility pursuant to R.I.G.L. 39-1-2(20)." R.I.G.L. §39-1-2(12). National Grid is the sole entity within the state of Rhode Island that falls within this statutory definition.

[19] RI PUC Order, May 2012, DOCKET NO. 4206.

> make up for the reduced revenues attributable to the warmer temperatures. The annual adjustments would account for changes other than weather, such as decreased revenues due to energy efficiency, increased revenues due to favorable economic conditions, and other changes in revenues. Under the settlement, customer charges for residential customers would be reduced and existing declining rate blocks would be flattened.[20]

The Commission approved the settlement RDM. The order's opening statement follows:

> In this order, the Commission approves, for the first time in New Hampshire, a decoupling mechanism which allows rate adjustments for weather, energy efficiency, economic effects, and other variables and allows Liberty to earn distribution revenues on a per customer basis, thus eliminating substantial revenue risks. Paired with this innovative decoupling mechanism is a modified rate design that lowers fixed customer charges. The reduction in risk leads to a return on equity of 9.3 percent, which represents a 10-basis point reduction in the return on equity agreed to by Liberty, the OCA, and Staff.[21]

**Q. What conclusions do you draw from the states that have adopted revenue-related and cost-related modifications to traditional ratemaking?**

A. Based on the widespread adoption of decoupling mechanisms, I conclude that there is general understanding that: (a) decoupling mechanisms are now viewed as an appropriate ratemaking approach that remove disincentives to effectively promote EE programs and offset the overall effect of conservation on revenues and earnings; (b) cost tracking measures are now viewed as an appropriate approach to partially offset the effect of capital spending plans on earnings between rate cases; and (c) the combination of a

[20] Order No. 26,122 (Apr. 27, 2018) in Docket No. DG 17-048, pages 6-7.
[21] *Id.* at page 1.

decoupling mechanism paired with an appropriate cost tracking measure may be necessary to provide a reasonable opportunity to earn a fair return.

### 2. Summary and Conclusion to Decoupling Overview

**Q. Please summarize your findings about decoupling.**

A. Over the past decade or longer, there has been considerable attention given to decoupling, which I believe is the result of a growing acceptance that decoupling is a balanced and administratively manageable ratemaking tool that will: (a) break the link between a utility's revenues and the amount of energy that the utility delivers or sells; and (b) address problems with traditional ratemaking that are caused by long term trends of declining customer energy usage and, more recently, the challenges of customer-owned DG and plans for changes in rate design.

I have found that, because a number of states have adopted decoupling mechanisms over the last decade, there are now rich sources of data available concerning features of RDMs that have been implemented and issues related to the administration and implementation of RDMs, including, for example, RDM calculations and filing documentation.

## IV. GRANITE STATE ELECTRIC'S EXPERIENCE

### A. Introduction

**Q. In Section III above, you provided a discussion of circumstances that would support the implementation of an RDM. Do those circumstances apply specifically to Granite State?**

A. Yes. As I will explain in the remainder of this section, Granite State's circumstances demonstrate that an RDM is appropriate and justified for the Company. Specifically, I will:

- Describe Granite State's current EE programs;
- Summarize the 2016 EERS Settlement Agreement;
- Describe and explain Granite State's recent customer and revenue per customer trends, as well as trends observed across New England;
- Demonstrate that Granite State's level of involvement in and support for EE programs warrant the implementation of an RDM; and
- Describe how changes in customer usage and adoption of customer-owned DG warrant a level of rate recovery protection for both customers and the Company that decoupling can provide.

### B. Granite State's Energy Efficiency programs

**Q. Please provide some background on Granite State's EE programs.**

A. Granite State has been offering EE programs to its customers since 2002 that provide rebates and technical support for residential and commercial customers who seek to minimize their energy use.[22] Table 2 below provides a summary of the actual and planned kWh savings and expenses that result from Granite State's EE programs.

**Table 2: Granite State Electric Energy Efficiency Program Savings and Expenses[23]**

| Year | Actual / Estimate | Program Expenses | Annual kWh | Lifetime kWh | Winter kW | Summer kW |
|---|---|---|---|---|---|---|
| 2017 | Actuals | 2,300,775 | 6,298,678 | 83,062,223 | 909 | 1,071 |
| 2018 | Preliminary Actuals | 2,747,677 | 7,716,293 | 92,613,350 | 1,114 | 1,312 |
| 2019 | **Forecast** | 4,284,216 | 9,224,361 | 117,844,688 | 1,132 | 1,190 |

**Q. Is the intent of the EE program's performance incentive payment to compensate Granite State for foregone EE revenues?**

A. No. The performance incentive is intended to "incent the utilities to aggressively pursue achievement of the performance goals of their energy efficiency programs," and "to motivate the companies to achieve or exceed program goals."[24] It is not intended to offset Granite State's foregone EE revenues.

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22 Referred to as the "Core programs" in the EERS Settlement Agreement.
23 Values to be finalized and reported to NHPUC by May 31, 2019.
24 *Energy Efficiency Programs for Gas and Electric Utilities,* Order No. 24,203 at 13 (Sept. 5, 2003).

### C. The EERS Settlement Agreement

**Q. Please describe the EERS Settlement Agreement.**

A. The Company, as one of the Settling Parties, entered into a comprehensive Settlement Agreement in the EERS docket on April 27, 2016.[25] The Settlement Agreement represented the Parties' implementation of the approved EERS in New Hampshire,[26] and specifically:

1) Extended the Core programs;
2) Required implementation of an LRAM, commencing January 1, 2017 (capped at 110% of planned annual savings);
3) Contemplated the subsequent implementation of a decoupling mechanism to replace the LRAM;
4) Agreed to implement the EERS commencing January 1, 2018;
5) Retained the Performance Incentive, with modifications;
6) Increased the low-income share of the overall energy efficiency budget; and
7) Included other legal provisions.

The Commission approved the Settlement Agreement in Order No. 25,932 (Aug. 2, 2016).

[25] Docket No. IR 15-072, "Electric and Natural Gas Utilities - Energy Efficiency Investigation" dated March 13, 2015.
[26] Settlement Agreement, page 2.

**Q. Please describe Granite State's Implementation of the LRAM.**

A. Granite State implemented the LRAM effective January 1, 2017. This LRAM will remain in effect (as part of the System Benefits Charge "SBC") until it is replaced by the proposed decoupling mechanism described in Section V below.

**Q. Did the Commission's Order approving the EERS Settlement Agreement specifically require the Utilities, such as Granite State, to implement decoupling?**

A. Yes. The Commission approved the Settling Parties' proposed LRAM and recognized that some parties prefer decoupling to an LRAM. Specifically, the Order states:

> We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC)) are *required* to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before. (Emphasis added.) [27]

**Q. Is it the Company's position that proposing a decoupling mechanism in the instant proceeding comports with the Settlement Agreement and the Order?**

A. Yes. The phrase "if not before" from the above quote clearly allows the Company to propose a decoupling mechanism prior to the end of the first EERS triennium, if desired. Further, as evidenced by the Commission's approval of EnergyNorth's decoupling mechanism, Granite State's proposal is valid and timely.

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[27] Order No. 25,932 at 60.

### D. Impact of Customer Consumption Trends on Granite State Electric

**Q. Please describe the trends that can be observed in Granite State's customer and sales data.**

A. Analysis of UPC and customer trends reveals that Granite State's use per customer has been relatively flat over the last four years, with an annual decline of approximately 0.4%. Granite State's retail customers and sales are shown in the table below.

**Table 3: Granite State Customer & Sales Data**

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| Retail Customers | 43,189 | 43,705 | 43,692 | 43,911 | 44,145 |
| Retail Sales, (MWh) | 910,825 | 931,776 | 909,124 | 893,577 | 917,100 |
| Use per Customer | 21.09 | 21.32 | 20.81 | 20.35 | 20.77 |
| Retail Cust. Growth | | | | | 0.55% |
| Sales Growth | | | | | 0.17% |
| UPC Growth | | | | | -0.37% |

Also shown in this table is the flat or declining growth of overall retail customers and retail sales over the past several years.[28]

**Q. What are the major contributors to declining UPC?**

A. Categorically, declining UPC can be attributable to:

1) Utility-sponsored Energy Efficiency (EE)/DSM programs;
2) Customer self-funded conservation measures;

[28] As explained earlier in Section III. C this trend is not expected to continue due to the growth of residential customers from the Tuscan Village development that is ongoing in Salem, New Hampshire.

3) Improvements in appliance efficiencies and building code requirements;
4) Consumer responsiveness to prices and/other economic and demographic factors; and
5) Continued customer adoption of DG, such as solar PV.

**Q. Please explain each of these factors.**

A. Utility-sponsored EE/DSM programs represent the Core programs, plus any additional programs contemplated in the EERS. These measures result in direct energy efficiency spending for Granite State customers. Each program will have an avoided unit of energy and known levels of participation.

Customer self-funded conservation measures are the result of customers acting independently of utility-sponsored programs (e.g., when a customer installs insulation purchased at a home improvement store). Unlike company-funded conservation programs that track actual installed energy efficiency measures, the utility does not track customer-funded installations.

Appliance efficiencies and building code changes affect customer usage whenever an existing (less efficient) appliance is replaced by a new (more efficient) one, and new housing stock replaces old stock. There are known changes to building requirements and appliance efficiency standards that have been enacted over the past few decades. These include increased appliance efficiency requirements for furnaces and hot water heaters. Additionally, New Hampshire has passed a series of more stringent building codes consistent with national standards.

Price elasticity and economic impact on usage can be estimated using econometric modeling but will have a lesser degree of accuracy compared to known and measurable EE/DSM installations. Further, changes in demographics (e.g., number of people per household, number of residents in a service territory or state) can also influence UPC.

Adoption of customer-owned DG, such as solar PV, results in reduced electricity usage for those customers. As a group, these customers will begin to make material contribution to class use per customer as customer adoption rates increase.

**Q. Please summarize why Granite State is proposing, and should be granted, a decoupling mechanism.**

A. The EERS Settlement Agreement states that each of the utilities in the state shall seek approval of a new decoupling mechanism, or another mechanism as an alternative to the LRAM. The Company's preferred solution is decoupling. Decoupling is now a mainstream ratemaking tool in New England and across the U.S. Granite State's proposed structure, detailed in Section V below, follows this nationally preferred and accepted design.

Decoupling further solves a long-standing ratemaking issue. There are clear trends that sales[29] and UPC are flat or declining for Granite State, which have impacted the Company's ability to earn its allowed rate of return. The factors contributing to this declining use reach well beyond utility-funded programs. The discussion above details

[29] Although the trends in customer counts and sales will change due to the aforementioned Tuscan Village development, UPC is still expected to follow the same flat or declining trend.

the main contributors to declining UPC, including customer-funded conservation, stricter appliance efficiency and building codes, economic and demographic drivers, and adoption of customer-owned DG. None of these factors are within the control of the Company, and the Company should not be penalized between general rate cases for these exogenous events. Decoupling frees Granite State from the negative effects of these causes of declining UPC and enables unfettered support and promotion of the State's energy efficiency goals.

Lastly, decoupling enables innovative rate design. With the assurance that both non-participating customers and the Company will not be financially harmed by participating DG customer adoption of new technologies, Granite State can propose new rate structures that promote DG and further the rate design goals of cost causation. For example, a new opt-in solar PV TOU rate could be introduced. Participating customers would accept the risk of paying too much if their usage profiles do not change as expected and reap the rewards of TOU rates if their usage patterns align with the lower-priced off-peak periods. Regardless of the outcome for the participating TOU customer, non-participating customers or the Company will be "made whole" through the decoupling mechanism, which adjusts what customers pay to match a per-customer target, thereby protecting customers from over collection when sales are high, and protecting the company from under collection when sales are low.

# V. GRANITE STATE'S DECOUPLING PROPOSAL

## A. Details of Granite State's Proposed Decoupling Mechanism

**Q. Please provide a general description of the decoupling mechanism that Granite State is proposing.**

A. The Company is proposing an RPC decoupling mechanism that will be applied to all customers in all firm tariffed rate classes. Calculations of over or under recovery from targeted RPC per class will be calculated monthly and accumulated for a yearly total. This yearly total will then be either refunded or collected from customers on a uniform volumetric basis.

**Q. Please explain the approach that the Company is proposing for the true up calculation.**

A. As described earlier in my testimony, the Company's proposed decoupling mechanism is an RPC RDM. An RPC RDM is critical to providing the Company with some opportunity to earn a reasonable return between rate cases, and retain revenues related to the growth in customers.

**Q. Which rate classes will be included in the Company's proposed RDM?**

A. Granite State proposes to include all tariffed customer classes, except Outdoor Lighting Service Rate M[30], in the RDM true up calculations, and to apply RDM rate adjustments to these rate classes on a uniform volumetric basis.

[30] Rate M is priced on a fixed-charge basis; therefore, no volumetric-related revenue variances exist and decoupling is unnecessary and would yield a zero adjustment under the proposed formula.

It is appropriate to apply the RDM to all customers because (a) all Granite State customers are eligible for the Company's EE programs, and (b) Residential and C&I customers are likely to implement conservation efforts that are not directly associated with Granite State's EE programs.

**Q. How will the Company's customers be grouped for purposes of administering the proposed RDM?**

A. Each of the Company's rate classes will be separate groups (i.e., stand-alone) for purposes of the RDM calculation (the determination of over-or-under-collection).

**Q. Please explain how the RDM rate adjustments are calculated.**

A. The Company will calculate annual RDM rate adjustments based on the prior year's RDM revenue shortfalls or surpluses for each RDM customer group. Once these class total over- or under-collections are determined, they will be summed together to derive the total decoupling dollar adjustment. The decoupling rate will be determined on a uniform volumetric basis, meaning that the total decoupling dollar adjustment will be divided by total system distribution sales to derive a single decoupling rate per kWh.

**Q. Please explain how actual revenues per customer will be calculated.**

A. Actual Revenues per Customer, by RDM Rate Class, will be calculated directly from the actual booked base distribution revenues and actual booked average number of customers. The Company will calculate the RDM Actual Revenues per Customer and the RDM revenue shortfall/surplus monthly on a calendar month basis. At the end of the adjustment period, the Company will sum all of the monthly data and will calculate RPC on an annual basis.

**Q. How will new customers be treated in the Company's proposed RDM?**

A. The Company will include new customers in the RDM calculations. These customers will be charged the rate adjustments associated with the RDM, and the calculations of actual revenues per customer will include the new customers.

**Q. How does the proposed Granite State RDM compare to the EnergyNorth RDM approved by the Commission in Docket No. DG 17-048?**

A. Granite State's proposed RDM is very similar to EnergyNorth's RDM. There are some minor differences. First, EnergyNorth's tariffs are seasonal, which requires a biannual RDM calculation. Second, EnergyNorth has a "real-time" component of its RDM, which trues up the monthly weather-related variances on customer bills in the month in which the weather variance occurred. Because Granite State's loads are less weather-dependent, a real-time RDM weather component is not necessary. The annual RDM calculation will capture all variances, including weather-related variances.

**Q. To summarize, please describe how the Company's proposed RDM will be calculated and applied.**

A. As a general summary of my testimony in this section, RDM adjustments will be determined prior to the start of adjustment period by (1) calculating Target Revenue[31] per

[31] The Target Revenue per customer for each rate group will be determined from the revenue requirement approved in this proceeding.

customer for each RDM Rate Class; (2) calculating actual revenue per customer for that period (i.e. the most recently completed period) for each RDM Rate Class; (3) calculating the difference between Target and actual revenue per customer; (4) calculating RDM Rate Class revenue shortfalls or surpluses by multiplying the revenue per customer differences times actual average annual customers for each rate Class; (5) calculating the Company total revenue shortfall or surplus by summing the RDM Rate Class revenue shortfalls or surpluses; and lastly (6) calculating the RDM adjustment by dividing the Company total revenue shortfall or surplus by projected sales for the upcoming period.

This adjustment will also include a reconciliation of the prior period authorized Company total revenue shortfall or surplus to actual revenues recovered or returned in the prior period.

**Q. Have you prepared a schedule to illustrate how the RDM calculations would be made?**

A. Yes, I have prepared Attachments GHT-2 and GHT-3 for that purpose. To prepare this hypothetical illustration I used actual Company data for the period from January 2013 through December 2018 to show:

- The calculation of the Target RPC for the firm rate classes. I developed the Target RPC for a 2013 Test Year, which is shown in Table 4 below, and Attachment GHT-2.

- The calculation of actual RPCs, RDM revenue shortfalls or surpluses per customer, and total revenue shortfalls or surpluses, which is shown in Attachment GHT-3.
- The hypothetical calculations for all years (2013–2018) utilize 2018 rates.[32]

**Q. Please summarize the results of the analysis that is provided in Attachments GHT-2 and GHT-3.**

A. I have prepared Table 4,[33] below, to summarize the annual revenue per customer, from 2013 through 2018:

**Table 4: RDM Class Accrual Analysis**

| 2013 TARGET | DOD2 | D10 | G01 | G02 | G03 | T00 | V00 |
|---|---|---|---|---|---|---|---|
| 2013 Target RPC | $ 561 | $ 635 | $ 15,068 | $ 1,281 | $ 918 | $ 835 | $ 934 |
| 2014 RPC | $ 562 | $ 653 | $ 14,484 | $ 1,275 | $ 935 | $ 861 | $ 1,041 |
| 2015 RPC | $ 561 | $ 622 | $ 14,773 | $ 1,280 | $ 959 | $ 814 | $ 1,150 |
| 2016 RPC | $ 549 | $ 607 | $ 14,503 | $ 1,261 | $ 941 | $ 803 | $ 1,150 |
| 2017 RPC | $ 547 | $ 612 | $ 14,332 | $ 1,238 | $ 928 | $ 804 | $ 1,201 |
| 2018 RPC | $ 562 | $ 627 | $ 14,525 | $ 1,239 | $ 932 | $ 812 | $ 1,189 |

**Q. How will the revenue shortfalls or surpluses be billed to customers?**

A. As described above, a singular rate per kWh will be calculated annually based on the sum of the accrued class RDMs and billed the subsequent year. For example, the 2020 total accrued shortfall/over-collection will be collected/refunded over the 2021 period. The rate per kWh will be calculated on a total system basis and applied to all rate classes.

32 Granite State Electric Rate Schedule as of November 1, 2017. https://new-hampshire.libertyutilities.com/uploads/Rates%20and%20Tariffs/Electric%202017/Summary-of-Rates-GSE-November-2017.pdf

33 Please see Attachments GHT-2 andGHT- 3 for supporting calculations. Also, Table 5 below provides further explanatory information regarding these hypothetical results.

Based on the sample data, the billing of the calculated RDMs is as follows:

**Table 5: Calculation of RDM Billing Rates**

| Billing Year | DOD2 | D10 | G01 | G02 | G03 | T00 | V00 | Total Company Adjustment | Per kWh Adjustment |
|---|---|---|---|---|---|---|---|---|---|
| 2015 | $53,919 | $8,168 | ($79,535) | ($5,413) | $92,027 | $28,286 | $1,922 | $99,374 | $ 0.000108 |
| 2016 | $10,855 | ($5,690) | ($39,654) | ($1,313) | $211,250 | ($22,254) | $3,395 | $156,589 | $ 0.000172 |
| 2017 | ($420,090) | ($12,178) | ($77,773) | ($18,227) | $122,229 | ($31,807) | $3,275 | ($434,571) | $ (0.000481) |
| 2018 | ($484,645) | ($10,152) | ($101,752) | ($38,209) | $49,493 | ($30,574) | $4,052 | ($611,788) | $ (0.000687) |
| 2019 | $47,784 | ($3,495) | ($75,644) | ($37,824) | $75,291 | ($22,772) | $3,858 | ($12,803) | $ (0.000014) |

The 2015 adjustment of $0.000108/kWh reflects the difference between the 2013 Target RPC and the 2014 Actual RPC for each rate class. This difference is then multiplied by the average monthly 2014 customer count in each rate class, to be billed in 2015. The dollar surplus or shortfall ($99,374 for billing year 2015) is then divided by the total Company kWh for the rate classes in question. In this example I have used actual 2014 kWh sales to calculate the adjustment. However, the going forward adjustment will use projected sales for the upcoming period to calculate the per-kWh charge or credit on customer bills. More detail on Table 5 is provided in Attachment GHT-3.

**Q. Please describe the timing of RDM calculations, filings, and rate adjustments.**

A. The RDM calculations will be calculated annually based on the first full 12-month period following implementation of new rates. The Company will file its proposed RDM calculations and associated proposed rate adjustments with the Commission within 60 days. Assuming a Commission review period consistent with EnergyNorth, the Company will receive approval to begin billing the rate adjustment commencing with bills three months following the completion of the decoupling year. This process is repeated annually until the Company's next rate case.

**Q. Has the Company prepared an RDM tariff provision?**

A. Yes. The Company's proposed tariff includes provisions for the RDM and is included in the proposed tariff in this proceeding. This new RDM tariff replaces the current "Lost Revenue Adjustment Mechanism" tariff provisions, as the proposed RDM replaces the LRAM in its entirety.

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

A. Yes, it does.

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# Gregg H. Therrien
## Assistant Vice President

Gregg Therrien is a former utility Director who has held leadership positions at Connecticut Natural Gas Corporation and affiliated companies for more than 19 years. Most recently, he served as the Director, Gas Construction at Connecticut Natural Gas and The Southern Connecticut Gas Company and Director, Regulatory & Tariffs at UIL Holdings, Inc. Mr. Therrien's experience includes natural gas distribution system operations and construction practices, regulatory strategies, natural gas growth, infrastructure replacement programs, integrated resource planning and technical rate case issues such as utility cost of service, rate design, tariff writing and administration, as well as pricing, gas cost accounting, gross margin, and load forecasting for regulated utilities. Mr. Therrien has an M.B.A. from the University of Connecticut and a B.S. in Finance from Bryant University, and is also a certified Project Management Professional (PMP).

### REPRESENTATIVE EXPERIENCE

Representative responsibilities performed for Connecticut gas utilities include:

**Regulatory Affairs**

- Led the preparation, filing, discovery and implementation of several rate cases
- Designed rates and prepared testimony, and served as the primary rate design witness
- Prepared, testified, and implemented revenue requirement rate mechanisms for new customer growth and pipeline replacement programs
- Prepared gas Integrated Resource Plans
- Prepared assessment of forecast methodology and forecast accuracy of gas demands
- Prepared validation of sales forecast and analysis of declining use per customer
- Proposed, testified, and implemented Connecticut's first gas decoupling mechanism
- Key contributor in settlement negotiations for rate cases and other litigated regulatory matters, including the LDC gas expansion plan
- Prepared testimony and exhibits for bi-annual Purchased Gas Adjustment proceedings
- Prepared testimony and new program tariffs in support of gas unbundling

**Business Strategy and Operations**

- Led a newly-created gas construction organization, leveraging project management practices to plan and execute a $100M annual capital budget
- Responsible for RFP development and bid selection of five-year contracts of local, regional and national gas construction and restoration contractors representing approximately 70 work crews
- Developed and implemented a tablet-based QA/QC inspection program
- Developed annual sales and revenue operating budgets
- Developed rate of return new customer acquisition model

- Led several process improvement teams
- Successfully negotiated contracts with large cogeneration users avoiding system bypass and obtaining regulatory approval

**Consultancy**

- Regulatory risk assessments
- Gas infrastructure replacement program technical and financial analysis and testimony
- Market analysis for international clients
- M&A due diligence (regulatory)
- Electric distribution alternative rate plan analysis
- Economic Development tariff development
- Decoupling testimony assistance for a Western Gas LDC
- Decoupling and Rate Design expert witness testimony for a New England Gas LDC
- Revenue Requirements witness for an electric distribution company
- Regulatory rate strategies for a vertically-integrated electric utility
- Testified on behalf of a New England gas LDC on the subjects of decoupling, capital trackers and rate design
- Developed an Alternative Rate Plan for a New England gas LDC
- Rate comparison study for the Government of Alberta, Canada
- Developed a cost of service-based pricing model for a 10MW fuel cell developer
- Power procurement consultancy for a New England investor-owned water utility

**PROFESSIONAL HISTORY**

**Concentric Energy Advisors, Inc. (2016 – Present)**
Assistant Vice President

**AVANGRID and affiliated companies (2016)**

**Connecticut Natural Gas and The Southern Connecticut Gas Company (2014 – 2016)**
Director, Gas Construction

**UIL Holdings, Inc. (2010-2014)**
Director, Regulatory & Tariffs

**Iberdrola S.A. / Energy East Corporation / Connecticut Natural Gas and The Southern Connecticut Gas Company (2001-2010)**
Director, Regulatory & Pricing / Director, Pricing & Analysis

**Connecticut Natural Gas Corporation (1997-2001)**
Manager, Pricing

**United Technologies, Inc. – Pratt & Whitney**
**Turbo Power & Marine Systems (1996-1997)**
Manager, Financial Planning & Analysis

**Pratt & Whitney Aircraft**
Business Unit Cell Leader, Overhaul & Repair / Manufacturing - turbine airfoils (1994-1996)

Financial Analyst, Commercial Engine Business (1987-1994)

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## EDUCATION AND CERTIFICATION

Master of Business Administration, University of Connecticut, Concentration in Finance, 1993

B.S., Bryant University (College), Finance, 1987

Certified Project Management Professional (PMP)

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## LEADERSHIP

**Connecticut Economic Resource Center (CERC)**
Member, Board of Directors 2008 – 2011, Treasurer, 2011-2016

**Connecticut Power and Energy Society (CPES)**
Member, Board of Directors 2017-2018
Executive Secretary and Director, 2018 to present

**AGA Executive Leadership Development Program - 2012**

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## AFFILIATIONS

**American Gas Association**
State Affairs Committee, 2001 - present

**Northeast Gas Association**

**Project Management Institute**

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| SPONSOR/APPLICANT | DATE | DOCKET NO. | SUBJECT |
|---|---|---|---|
| **Connecticut Public Utilities Regulatory Authority** | | | |
| Yankee Gas Services (Eversource Energy) | 2018 | Docket No. 18-05-10 | Distribution Rate Case<br>Rate design, decoupling, and capital trackers |
| Connecticut Natural Gas Corporation & Southern Connecticut Gas Company | 2016 | Docket No. 16-04-10 | State of Connecticut LDC Gas Expansion Plan: System Expansion Reconciliation<br>- Capital Expenditures, System Improvement/Reinforcement Projects |
| Connecticut Natural Gas Corporation & Southern Connecticut Gas Company | 2014 | Docket No. 13-06-02RE01 | State of Connecticut LDC Gas Expansion Plan<br>- Settlement Agreement |
| Connecticut Natural Gas Corporation & Southern Connecticut Gas Company | 2013 | Docket No. 13-06-02 | State of Connecticut LDC Gas Expansion Plan<br>- Rates, Hurdle Rate analysis, Demand forecast, Rate Mechanism |
| Connecticut Natural Gas Corporation | 2013 | Docket No. 13-06-08 | Distribution Rate Case<br>- Revenue Requirements, Cost of Service, Rate Design, Demand Forecast, and Forecasted Revenues; Decoupling, DIMP and System Expansion Reconciliation Rate Mechanisms, Tariffs |
| The Southern Connecticut Gas Company | 2013 | Docket No. 99-10-25RE01 | Firm Transportation Service Agreement and Gas Exchange Agreement<br>- Review of Revenue Requirement Allocation |
| Connecticut Natural Gas Corporation & Southern Connecticut Gas Company | 2011 | Docket No. 08-12-06RE02, 08-12-07RE02 | Settlement Agreement RE: Resolve Stayed Decisions and Orders from Appealed CNG and SCG Rate Cases, and resolve SCG overearnings |
| The Southern Connecticut Gas Company | 2011 | Docket No. 10-12-17 | Just and Reasonable Rates – Potential Overearnings Investigation |
| **Illinois Commerce Commission** | | | |

| SPONSOR/APPLICANT | DATE | DOCKET NO. | SUBJECT |
|---|---|---|---|
| The Peoples Gas Light & Coke Company | 2017 | Docket No. 16-0376 | Gas Distribution Aging Infrastructure Peer Utility Benchmark Study, Affordability |
| **Maine Public Utilities Commission** | | | |
| Emera, Maine | 2017 | Docket No. 2017-00198 | Electric Distribution Revenue Requirements |
| **New Hampshire Public Utilities Commission** | | | |
| Liberty Utilities – New Hampshire d/b/a/ EnergyNorth Natural Gas | 2017 | DG 17-048 | Revenue Decoupling<br>Rate Design |

Liberty Utilities (Granite State Electric) Corp.
d/b/a Liberty Utilities

| Ln. | | Year | Domestic DOD2 | Domestic - Opt. Peak D10 | General TOU G01 | General Long Hour G02 | General Service G03 | Limited All Electric T00 | Ltd Comm Space Heating V00 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | | Year | DOD2 | D10 | G01 | G02 | G03 | T00 | V00 |
| 2 | | | **Average Annual Customers** | | | | | | |
| 3 | | 2013 | 34,928 | 442 | 131 | 866 | 5,608 | 1,140 | 19 |
| 4 | | 2014 | 34,695 | 445 | 136 | 873 | 5,493 | 1,104 | 18 |
| 5 | | 2015 | 33,828 | 434 | 134 | 864 | 5,229 | 1,050 | 16 |
| 6 | | 2016 | 34,254 | 440 | 137 | 886 | 5,295 | 980 | 15 |
| 7 | | 2017 | 34,387 | 440 | 138 | 893 | 5,315 | 965 | 15 |
| 8 | | 2018 | 34,476 | 439 | 139 | 898 | 5,336 | 953 | 15 |
| 9 | | | **Annual Sales (kWh)** | | | | | | |
| 10 | | 2013 | 280,042,782 | 5,702,053 | 377,937,412 | 154,871,617 | 90,629,128 | 18,814,877 | 305,164 |
| 11 | | 2014 | 279,196,959 | 5,965,359 | 370,619,921 | 154,285,847 | 90,771,006 | 18,923,176 | 329,989 |
| 12 | | 2015 | 269,422,528 | 5,439,789 | 376,092,571 | 154,003,498 | 89,091,467 | 16,772,128 | 324,718 |
| 13 | | 2016 | 266,669,433 | 5,335,923 | 374,626,889 | 152,168,320 | 88,228,024 | 15,382,945 | 312,923 |
| 14 | | 2017 | 266,510,826 | 5,393,098 | 370,085,246 | 146,695,170 | 86,971,720 | 15,168,199 | 329,446 |
| 15 | | 2018 | 277,319,661 | 5,565,393 | 380,035,050 | 147,610,927 | 87,865,079 | 15,166,045 | 325,118 |
| 16 | | | **GSE TARIFF RATES BY RATE CLASS** | | | | | | |
| 17 | Monthly Charges | | DOD2 | D10 | G01 | G02 | G03 | T00 | V00 |
| 18 | Customer Charge (Fixed) | | $ 14.54 | $ 14.54 | $ 378.73 | $ 63.15 | $ 14.54 | $ 14.54 | $ 14.54 |
| 19 | Distribution Charge ($/kWh) | | $ 0.04061 | | | $ 0.00200 | $ 0.04603 | $ 0.04004 | $ 0.04732 |
| 20 | Dist. Charge ($/kWh >250) | | $ 0.05273 | | | | | | |
| 21 | Demand Charge per kW | | | | $ 8.07 | $ 8.12 | | | |
| 22 | On Peak per kWh | | | $ 0.10422 | $ 0.00516 | | | | |
| 23 | Off Peak per kWh | | | $ 0.00141 | $ 0.00152 | | | | |
| 24 | Blended Peak Rate per kWh | | | $ 0.03568 | $ 0.00273 | | | | |
| 25 | | | | | | | | | |

Liberty Utilities (Granite State Electric) Corp.
d/b/a Liberty Utilities

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 26 | **2013 TARGET** | | **DOD2** | **D10** | **G01** | **G02** | **G03** | **T00** | **V00** |
| 27 | Customer Charge (Annual $) | 2013 | $ 6,094,296 | $ 77,135 | $ 596,500 | $ 656,381 | $ 978,484 | $ 198,864 | $ 3,315 |
| 28 | Distribution Charge (Annual $) | 2013 | $ 4,255,319 | | | $ 309,743 | $ 4,171,659 | $ 753,348 | $ 14,440 |
| 29 | Distribution Charge (Annual $) | 2013 | $ 9,241,343 | $ 203,449 | $ 1,033,029 | | | | |
| 30 | Demand Charge per kW | | | | $ 348,168 | $ 143,557 | | | |
| 31 | 2013 Target | | $ 19,590,957 | $ 280,584 | $ 1,977,697 | $ 1,109,681 | $ 5,150,143 | $ 952,211 | $ 17,755 |
| 32 | **2013 Target RPC** | | **$ 561** | **$ 635** | **$ 15,068** | **$ 1,281** | **$ 918** | **$ 835** | **$ 934** |
| 33 | | | | | | | | | |
| 34 | **2014** | | **DOD2** | **D10** | **G01** | **G02** | **G03** | **T00** | **V00** |
| 35 | Customer Charge (Annual $) | 2014 | $ 6,053,636 | $ 77,600 | $ 619,299 | $ 661,736 | $ 958,430 | $ 192,542 | $ 3,144 |
| 36 | Distribution Charge (Annual $) | 2014 | $ 4,226,928 | | | $ 308,572 | $ 4,178,189 | $ 757,684 | $ 15,615 |
| 37 | Distribution Charge (Annual $) | 2014 | $ 9,233,606 | $ 212,844 | $ 1,013,028 | | | | |
| 38 | Demand Charge per kW | | | | $ 341,427 | $ 143,014 | | | |
| 39 | 2014 Target | | $ 19,514,170 | $ 290,444 | $ 1,973,754 | $ 1,113,322 | $ 5,136,620 | $ 950,226 | $ 18,759 |
| 40 | **2014 RPC** | | **$ 562** | **$ 653** | **$ 14,484** | **$ 1,275** | **$ 935** | **$ 861** | **$ 1,041** |
| 41 | **2015** | | **DOD2** | **D10** | **G01** | **G02** | **G03** | **T00** | **V00** |
| 42 | Customer Charge (Annual $) | 2015 | $ 5,902,306 | $ 75,744 | $ 610,714 | $ 654,603 | $ 912,333 | $ 183,147 | $ 2,748 |
| 43 | Distribution Charge (Annual $) | 2015 | $ 4,226,928 | | | $ 308,007 | $ 4,100,880 | $ 671,556 | $ 15,366 |
| 44 | Distribution Charge (Annual $) | 2015 | $ 8,855,401 | $ 194,092 | $ 1,027,986 | | | | |
| 45 | Demand Charge per kW | | | | $ 346,469 | $ 142,752 | | | |
| 46 | 2015 Target | | $ 18,984,636 | $ 269,836 | $ 1,985,169 | $ 1,105,362 | $ 5,013,213 | $ 854,703 | $ 18,114 |
| 47 | **2015 RPC** | | **$ 561** | **$ 622** | **$ 14,773** | **$ 1,280** | **$ 959** | **$ 814** | **$ 1,150** |
| 48 | **2016** | | **DOD2** | **D10** | **G01** | **G02** | **G03** | **T00** | **V00** |
| 49 | Customer Charge (Annual $) | 2016 | $ 5,976,638 | $ 76,799 | $ 624,863 | $ 671,316 | $ 923,891 | $ 170,986 | $ 2,648 |
| 50 | Distribution Charge (Annual $) | 2016 | $ 4,173,165 | | | $ 304,337 | $ 4,061,136 | $ 615,933 | $ 14,808 |
| 51 | Distribution Charge (Annual $) | 2016 | $ 8,642,839 | $ 190,386 | $ 1,023,980 | | | | |
| 52 | Demand Charge per kW | | | | $ 345,119 | $ 141,051 | | | |
| 53 | 2016 Target | | $ 18,792,642 | $ 267,185 | $ 1,993,962 | $ 1,116,704 | $ 4,985,027 | $ 786,919 | $ 17,455 |
| 54 | **2016 RPC** | | **$ 549** | **$ 607** | **$ 14,503** | **$ 1,261** | **$ 941** | **$ 803** | **$ 1,150** |
| 55 | **2017** | | **DOD2** | **D10** | **G01** | **G02** | **G03** | **T00** | **V00** |
| 56 | Customer Charge (Annual $) | 2017 | $ 5,999,829 | $ 76,804 | $ 628,050 | $ 677,055 | $ 927,388 | $ 168,391 | $ 2,649 |
| 57 | Distribution Charge (Annual $) | 2017 | $ 4,189,358 | | | $ 293,390 | $ 4,003,308 | $ 607,335 | $ 15,589 |
| 58 | Distribution Charge (Annual $) | 2017 | $ 8,613,450 | $ 192,426 | $ 1,011,566 | | | | |
| 59 | Demand Charge per kW | | | | $ 340,935 | $ 135,978 | | | |
| 60 | 2016 Target | | $ 18,802,637 | $ 269,230 | $ 1,980,551 | $ 1,106,423 | $ 4,930,696 | $ 775,726 | $ 18,238 |
| 61 | **2017 RPC** | | **$ 547** | **$ 612** | **$ 14,332** | **$ 1,238** | **$ 928** | **$ 804** | **$ 1,201** |
| 62 | **2018** | | **DOD2** | **D10** | **G01** | **G02** | **G03** | **T00** | **V00** |
| 63 | Customer Charge (Annual $) | 2018 | $ 6,015,314 | $ 76,611 | $ 632,479 | $ 680,378 | $ 930,982 | $ 166,309 | $ 2,646 |
| 64 | Distribution Charge (Annual $) | 2018 | $ 4,200,170 | | | $ 295,222 | $ 4,044,430 | $ 607,248 | $ 15,385 |
| 65 | Distribution Charge (Annual $) | 2018 | $ 9,169,360 | $ 198,573 | $ 1,038,762 | | | | |
| 66 | Demand Charge per kW | | | | $ 350,101 | $ 136,827 | | | |
| 67 | 2018 Target | | $ 19,384,845 | $ 275,184 | $ 2,021,342 | $ 1,112,427 | $ 4,975,411 | $ 773,557 | $ 18,031 |
| 68 | **2018 RPC** | | **$ 562** | **$ 627** | **$ 14,525** | **$ 1,239** | **$ 932** | **$ 812** | **$ 1,189** |
| 69 | | | | | | | | | |

Liberty Utilities (Granite State Electric) Corp.
d/b/a Liberty Utilities

| Ln. | | DOD2 | D10 | G01 | G02 | G03 | T00 | V00 | |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Size of Adjustment Per Customer in 2015 | $ 1.55 | $ 18.36 | $ (583.67) | $ (6.20) | $ 16.75 | $ 25.63 | $ 106.68 | = (2014 RPC - 2013 RPC) |
| 2 | Size of Adjustment Per Customer in 2016 | $ 0.32 | $ (13.11) | $ (295.10) | $ (1.52) | $ 40.40 | $ (21.20) | $ 215.54 | = (2015 RPC - 2013 RPC) |
| 3 | Size of Adjustment Per Customer in 2017 | $ (12.26) | $ (27.67) | $ (565.66) | $ (20.57) | $ 23.08 | $ (32.46) | $ 215.79 | = (2016 RPC - 2013 RPC) |
| 4 | Size of Adjustment Per Customer in 2018 | $ (14.09) | $ (23.06) | $ (736.31) | $ (42.77) | $ 9.31 | $ (31.68) | $ 266.93 | = (2017 RPC - 2013 RPC) |
| 5 | Size of Adjustment Per Customer in 2019 | $ 1.39 | $ (7.96) | $ (543.55) | $ (42.13) | $ 14.11 | $ (23.89) | $ 254.35 | = (2018 RPC - 2013 RPC) |
| 6 | | | | | | | | | |
| 7 | **Billing Year** | **DOD2** | **D10** | **G01** | **G02** | **G03** | **T00** | **V00** | |
| 8 | 2015 | $ 53,919 | $ 8,168 | $ (79,535) | $ (5,413) | $ 92,027 | $ 28,286 | $ 1,922 | = Adjustment per Customer * 2014 Customers |
| 9 | 2016 | $ 10,855 | $ (5,690) | $ (39,654) | $ (1,313) | $ 211,250 | $ (22,254) | $ 3,395 | = Adjustment per Customer * 2015 Customers |
| 10 | 2017 | $ (420,090) | $ (12,178) | $ (77,773) | $ (18,227) | $ 122,229 | $ (31,807) | $ 3,275 | = Adjustment per Customer * 2016 Customers |
| 11 | 2018 | $ (484,645) | $ (10,152) | $ (101,752) | $ (38,209) | $ 49,493 | $ (30,574) | $ 4,052 | = Adjustment per Customer * 2017 Customers |
| 12 | 2019 | $ 47,784 | $ (3,495) | $ (75,644) | $ (37,824) | $ 75,291 | $ (22,772) | $ 3,858 | = Adjustment per Customer * 2018 Customers |
| 13 | | | | | | | | | |
| 14 | **Billing Year** | **Total Company Adjustment** | | | | | | | |
| 15 | 2015 | $ 99,374 | | | | | | | = sum(Ln 8) |
| 16 | 2016 | $ 156,589 | | | | | | | = sum(Ln 9) |
| 17 | 2017 | $ (434,571) | | | | | | | = sum(Ln 10) |
| 18 | 2018 | $ (611,788) | | | | | | | = sum(Ln 11) |
| 19 | 2019 | $ (12,803) | | | | | | | = sum(Ln 12) |
| 20 | | | | | | | | | |
| 21 | **Billing Year** | **per kWh Adjustment** | | | | | | | |
| 22 | 2015 | $ 0.0001080 | | | | | | | = (L15) / 2014 Sales |
| 23 | 2016 | $ 0.0001719 | | | | | | | = (Ln16) / 2015 Sales |
| 24 | 2017 | $ (0.0004814) | | | | | | | = (Ln17) / 2016 Sales |
| 25 | 2018 | $ (0.0006865) | | | | | | | = (Ln18) / 2017 Sales |
| 26 | 2019 | $ (0.0000140) | | | | | | | = (Ln19) / 2018 Sales |