STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 19-XXX

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

DIRECT TESTIMONY

OF

DAVID B. SIMEK

March 26, 2019

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

Q. Please state your name and position.

A. My name is David B. Simek. I am the Manager, Rates and Regulatory Affairs for Liberty Utilities Service Corp. ("Liberty"), which provides services to Liberty Utilities (Granite State Electric) Corp. ("Granite State" or "the Company"). I am responsible for providing rate and regulatory-related services for the Company.

Q. Please briefly describe your educational background and training.

A. I graduated from Ferris State University in 1993 with a Bachelor of Science in Finance. I received a Master's of Science in Finance from Walsh College in 2000. I also received a Master's in Business Administration from Walsh College in 2001. In 2006, I earned a Graduate Certificate in Power Systems Management from Worcester Polytechnic Institute.

Q. What is your professional background?

A. In August 2013, I joined Liberty Utilities as a Utility Analyst. I was promoted to a Lead Utility Analyst in December 2014, and to my current position in August 2017. Prior to my employment at Liberty Energy Utilities (New Hampshire) Corp., I was employed by NSTAR Electric & Gas ("NSTAR") as a Senior Analyst in Energy Supply from 2008 to 2012. Prior to my position in Energy Supply at NSTAR, I was a Senior Financial Analyst within the NSTAR Investment Planning group from 2004 to 2008.

Q. Have you previously testified or participated in proceedings before the Commission?

A. Yes. I have testified on numerous occasions before the Commission.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present Granite State's proposed rate adjustments for 2019 in accordance with the Company's reconciliation and adjustment provisions of its tariff, and the Company's Amended Restructuring Settlement Agreement approved in Docket No. DR 98-012 ("Amended Settlement Agreement"). The reconciliations and adjustments described in my testimony relate to the Stranded Cost Charge and Transmission Charge.

The purpose of the reconciliation analyses is to determine the difference between revenues collected under each charge and the Company's actual expenses. For each of the charges, the Company calculates an adjustment factor based on the result of each reconciliation, which is used to determine whether a refund to or recovery from customers is necessary.

Q. Did you perform your analyses consistent with processes and procedures for similar filings in previous years?

A. Yes. I have performed my analyses consistent with past methods and practices. The actual revenues and costs tie to the Company's books and are reported consistent with the July 2012–January 2018 revenues and costs currently being reviewed by PUC Audit

Staff. One enhancement was made with respect to Schedule DBS-4 for the Regional Greenhouse Gas Initiative ("RGGI") auction proceeds, and that is discussed further in Section V of my testimony.

Q. Are there months in the schedules that do not have actual expenses and revenues?

A. Yes. To address the fact that the filing is made two months prior to rates going into effect, and, thus, actual expenses and revenues are not available as of the filing date, I have included projected revenues and expenses for the months of March and April 2019.

Q. Please summarize the results of the adjustments and reconciliations which Granite State proposes to implement in 2019.

A. The Company proposes to implement the following adjustments to its rates beginning May 1, 2019, for usage on and after that date. The table below illustrates the current and proposed rates:

Average charge ($ / kWh)	Current	Proposed	Increase (Decrease)
Stranded Cost Charge	$(0.00040)	$(0.00070)	$(0.00030)
Stranded Cost Adjustment Factor	$(0.00052)	$(0.00035)	$ 0.00017
Transmission Service Charge	$ 0.02585	$ 0.02414	$(0.00171)
Transmission Service Cost Adjustment	$ 0.00557	$ 0.00162	$(0.00395)
RGGI Auction Proceeds Refund	$(0.00090)	$(0.00174)	$(0.00084)
LRAM due to Net Metering	$ 0.00008	$ -	$(0.00008)

Schedule DBS-1 presents the proposed stranded cost and the transmission rates.

III. <u>Stranded Cost Charge and the Stranded Cost Adjustment Factor</u>

Q. Please discuss, in general terms, the Company's proposed adjustment and reconciliation of its Stranded Cost Charge.

A. Granite State's Stranded Cost Charge is the sum of two components. The first is a uniform charge per kilowatt-hour ("kWh") that the Company charges all customers, which reflects the Contract Termination Charge ("CTC") assessed by New England Power Company ("NEP") for 2019. The second component is the Stranded Cost Adjustment Factor ("SCAF"), which is specific to each rate class. Both of these components are in accordance with the Company's Stranded Cost Adjustment Factor described on pages 19–20 of the Company's tariff.

Q. What changes are the Company proposing to the components of the Stranded Cost Charge?

A. Granite State is proposing to decrease the uniform charge per kWh related to the CTC assessed by NEP from a credit of ($0.00040) per kWh to a credit of ($0.00070) per kWh for the period beginning May 1, 2019. With respect to the SCAF, Granite State is proposing to change the load weighted-average from a credit of ($0.00052) per kWh to a load-weighted average credit of ($0.00035) per kWh.

Q. Please describe the purpose of the CTC assessed by NEP.

A. In 1996, the New Hampshire Legislature enacted RSA 374-F, a statute which directed the Commission to develop a restructuring plan to implement electric retail choice for all customers ("Restructuring"). Prior to Restructuring, Granite State customers were served by generation assets owned by the Company's then affiliate, NEP. During the Restructuring process, Granite State, NEP, and other parties agreed to a divestiture of NEP's generation assets. As part of its Electric Utility Restructuring Offer of Settlement in Docket No. DR 96-150 ("Restructuring Settlement"), the CTC was established to recover stranded costs associated with this divestiture, with such recovery terminating in 2020.

Q. Please describe the changes to the Stranded Cost Charge resulting from the changes in the CTC assessed by NEP for 2019.

A. In the 2019 CTC Reconciliation Report filed in Docket No. DE 19-025, NEP provided the reconciliation report to the Commission and the signatories to the Amended Settlement Agreement in accordance with Section 3.5 of the Wholesale Settlement approved by the Federal Energy Regulatory Commission. In that filing, NEP calculated the revised CTC rate for 2019 to be a credit of ($0.00070) per kWh as compared to the 2018 CTC of ($0.00040). The Company's rate change proposal with respect to the uniform per kWh component of the Stranded Cost Charge is simply a reflection of the change in the CTC rate.

Q. Please describe the Stranded Cost adjustment factors and the reconciliation used to determine those factors for each rate class.

A. The Company performs an annual reconciliation of its revenues from the Stranded Cost Charge billed to customers and recorded in its general ledger with the CTC expenses paid to NEP to arrive at adjustment factors for each rate class. Details for the reconciliation for the period May 2018 through April 2019 are in Schedule DBS-2.

Q. Has the Company prepared a reconciliation analysis for Stranded Cost revenues and expenses?

A. Yes. Schedule DBS-2, page 2 of 4, presents a reconciliation of actual stranded cost revenues and expenses for the period May 2018 through February 2019, and forecasted stranded cost revenues and expenses for the period March 2019 through April 2019. It should be noted that during the entire reconciliation period there were no expenses as the CTC rate from NEP was a credit (see column (c)). In addition, column (b) demonstrates that the Stranded Cost rate was a charge to customers only in the month of May 2018, and the remaining months were credits to customers. With the increase in the credit CTC rate from NEP effective January 1, 2019, the result is an over-collection of $318,677. Pages 3 and 4 of Schedule DBS-2 allocate the reconciliation to the various rate classes.

Q. Has the Company calculated proposed SCAFs for 2019?

A. Yes. Schedule DBS-2, page 1 of 4, calculates a SCAF per kWh, specific to each rate class, to be applied to all retail delivery service customers' bills for the period May 1, 2019, through April 30, 2020.

IV. Transmission Service Cost Adjustment Charge

Q. Please describe the Company's Transmission Service Cost Adjustment ("TSCA") charge.

A. The Company recovers its transmission-related expenses pursuant to the TSCA, which allows the Company to recover costs billed to it by ISO-New England and NEP through the ISO-New England Inc. Transmission, Markets, and Services Tariff ("ISO Tariff"). The TSCA charge is comprised of two components: a component for base transmission costs for the prospective period plus a component for the reconciliation of transmission revenue and expense for the previous period.

Q. What is the TSCA charge that the Company is proposing for effect on May 1, 2019?

A. The Company is proposing an average TSCA charge of $0.02576 per kWh for effect May 1, 2019, and is comprised of the base cost component of $0.02414 per kWh and the reconciliation component of $0.00162 per kWh. This average TSCA charge is a decrease of $0.00566 from the average charge that is currently in effect.

Q. Please describe the reconciliation analysis for transmission revenues and expenses for the previous period.

A. Schedule DBS-3, page 3 presents a reconciliation of actual transmission revenues and expenses for the period May 2018 through January 2019 and forecasted transmission revenues and expenses for the period March 2019 through April 2019.

Q. How was the reconciliation component of the TSCA charge derived?

A. The reconciliation component of the TSCA recovers under-recoveries of transmission costs or refunds over-recoveries of transmission costs, along with associated interest at the prime rate. This component of the TSCA charge was calculated by adding the projected under-collection of transmission expense as of April 30, 2019, from Schedule DBS-3, page 3, of $1,498,624, plus the working capital of ($9,803) calculated on DBS-3, page 5.

Q. Please explain the $1,498,624 under-collection that is calculated on page 3 of Schedule DBS-3.

A. The under-collection of $1,498,624 is driven by the May 1, 2018, beginning under-collection balance of $5,938,752 and a May 1, 2018, through April 30, 2019, estimated expense to revenue over-collection including interest of $4,440,128.

Q. How will the reconciliation component of the TSCA charge be implemented?

A. The reconciliation component of the TSCA charge will become effective for usage on and after May 1, 2019. This proposed component will be applied to bills of all customers taking delivery service.

Q. Why is the Company proposing new base transmission rates at this time?

A. The TSCA portion of the Company's tariff states that the base transmission rates shall be calculated annually based on a forecast of transmission costs to be incurred by the Company for the prospective period to provide transmission service to its retail delivery service customers. The rate at which these costs are collected is calculated separately for each of the Company's rate classes based on an allocation of transmission costs to each class using each class' contribution to coincident peak.

Q. What is the forecast of 2019 transmission costs?

A. As discussed in the testimony of John D. Warshaw included in this filing, the Company's transmission costs are estimated to be $22,176,454 in 2019. This forecast of transmission expense yields an average rate of $0.02414 per kWh, as compared to the currently effective average transmission rate of $0.02585 per kWh, exclusive of the reconciliation component. Based on these estimates, the Company is proposing new base transmission rates effective May 1, 2019, to recover the projected transmission costs to be incurred in the prospective period.

Q. Please describe the working capital calculation included in the filing.

A. The settlement agreement in Docket No. DE 16-383 provided, in part, that the Company may recover cash working capital on transmission costs through the transmission cost adjustment mechanism included in the Company's Annual Retail Rate Adjustment filing. In accordance with that settlement, the Company has included a transmission cash working capital amount in the calculation of its proposed transmission rates.

Q. What is the total amount of transmission working capital included in this filing?

A. The total working capital included in the TSCA charge is ($9,803) as shown on Schedule DBS-3, page 5. The detailed calculation of the expense lag is shown on Schedule DBS-3, page 6. The detailed calculation of the revenue lag is shown on Schedule DBS-3, page 7.

Q. How does the Company propose to design the base transmission rates effective May 1, 2019?

A. Since base transmission rates are unique by rate class, the first step in designing the proposed base transmission rates is to allocate forecasted transmission costs to each rate class. The Company implemented the same allocation methodology accepted by the Commission in previous Annual Retail Rate Adjustment filings, which is to allocate based on each rate class's contribution to system peak. The contribution to system peak by class is presented on Schedule DBS-3, page 2, and the allocation of transmission cost to each class is shown on Schedule DBS-3, page 1.

V. <u>RGGI Auction Proceeds</u>

Q. How does the Company propose to refund RGGI auction proceeds to delivery service customers?

A. Consistent with Order No. 25,664 in Docket No. DE 14-048, the Company will credit the RGGI rebate amount it receives from the allocation on a per kWh basis through its retail rate reconciliation mechanism that is adjusted on an annual basis. The Company has included a credit of ($0.00174) per kWh for RGGI auction proceeds in its transmission service charge for 2019, as shown on Schedule DBS-4. The credit of ($0.00174) per kWh is comprised of the estimated RGGI auction proceeds for May 2019 through April 2020 of ($712,617) and the reconciliation component through April 2019 of ($885,371). The total of ($1,597,989) is then divided by the estimated sales of 918,598,414 kWh to calculate the RGGI credit of ($0.00174) per kWh. In previous filings, the RGGI credit only included the reconciliation component.

VI. Net Metering Lost Revenue Adjustment Mechanism

Q. Is the Company seeking recovery of displaced distribution revenue associated with net metering?

A. No. The Company plans to file for a distribution rate case in April 2019 with a calendar year 2018 test year. Any 2018 displaced distribution revenue due to net metering will be accounted for within the Company's calculated revenue requirement within the distribution rate case. As a result, the $0.00008 per kWh current component of the Transmission Service Charge will be reduced to $0.00000 per kWh.

VII. Effective Date and Rate Impacts

Q. How and when is the Company proposing that these rate changes be implemented?

A. Consistent with the Commission's rules on the implementation of rate changes, the Company is proposing that all of the above rate changes be made effective for usage on and after May 1, 2019.

Q. Has the Company proposed a rate change for any other bill components to be effective on that same date?

A. Yes. On March 15, 2019, the Company filed its annual REP/VMP Reconciliation in which it requested a rate increase to its distribution rates for capital expenditures and vegetation management expenses from calendar year 2018. The Company also filed on March 12, 2019, its rate design and capital step compliance requirements from Docket No. DE 16-383.

Q. Has the Company provided Audit Staff a reconciliation of the over/under calculations as required by Order No. 26,140 in Docket No. DE 18-051?

A. Yes. On March 21, 2019, the Company submitted its transmission and stranded cost reconciliation of the accounting records back to July 2012 to Audit Staff for their review.

Q. Has the Company determined the impact of the transmission and stranded cost rate changes on customers' bills?

A. Yes. A bill comparison for an Energy Service residential customer with an average kWh usage of 650 has also been included in this filing in Schedule DBS-6. The net total bill impact of the rates proposed in this filing, as compared to rates in effect today, is a monthly bill decrease of $4.80, or 3.88%.

VIII. <u>Conclusion</u>

Q. Does this conclude your testimony?

A. Yes, it does.