State of New Hampshire
Public Utilities Commission

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

Docket No. DE 19-064

<u>Notice of Intent to File Rate Schedules</u>

Stipulation and Settlement Agreement Regarding Permanent Rates

This Stipulation and Settlement Regarding Permanent Rates (the "Agreement") is entered into as of the last date signed below by and among Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company"), the Office of the Consumer Advocate ("OCA"), the City of Lebanon ("City"), Clean Energy New Hampshire ("CENH"), and the Staff of the Public Utilities Commission ("Staff") (collectively, "Settling Parties"). This Agreement resolves all issues regarding Liberty's request for permanent rates in this proceeding.

I. INTRODUCTION

On March 27, 2019, Liberty filed with the Public Utilities Commission ("Commission") its notice of intent to file rate schedules seeking an increase in its annual distribution revenues. The Company filed its proposed rate schedules on April 30, 2019, and later updated its rate schedules through its rebuttal testimony, resulting in a requested $6.3 million permanent increase in annual distribution revenues. The Company also asked the Commission to approve a decoupling mechanism and a multi-year rate plan. The Company requested approval of a 10.0% return on equity and a capital structure consisting of 55% equity and 45% debt. The Company supported its filing with the direct testimony of a number of witnesses from the Company and outside consultants. The Commission suspended the rate schedules by Order No. 26,252 (May 13, 2019).

The OCA notified the Commission that it would participate in the docket on behalf of residential customers consistent with RSA 363:28, and the Commission granted the petitions to intervene of the City and CENH at the May 30, 2019, prehearing conference, and approved New Hampshire Department of Environmental Services' (NHDES) petition to intervene by secretarial letter dated July 25, 2019.

The Company's filing included a request for a temporary rate increase of $2.1 million. Based on the Company's filing, testimony from Company witnesses, and statements by Staff, the OCA, the City, and CENH that they did not object to the Company's temporary rate request, the Commission approved the requested temporary rate increase of $2,093,349, effective July 1, 2019. Order No. 26,267 (June 28, 2019). The order provided that any permanent rates approved by the Commission would be fully reconcilable back to the July 1, 2019, effective date of temporary rates.

Following the temporary rate order, the Company responded to numerous sets of data requests; the Commission's Audit Staff reviewed the Company's filing and issued its audit report; and Staff, the OCA, and the City filed testimony on several issues including revenue requirement, capital projects, rate design (including outdoor lighting rates for LED lighting fixtures and rates for charging Electric Vehicles), cost of capital, and step adjustments.

The Company conducted discovery on Staff's and OCA's testimony and filed rebuttal testimony. The Settling Parties then engaged in settlement discussions that resulted in this Agreement, which is intended to resolve all issues in this case. The Settling Parties recommend and request that the Commission approve this Agreement without modification.

II. TERMS OF AGREEMENT

A. Revenue Requirement and Rate of Return

The Settling Parties agree that the Commission should authorize an annual distribution revenue increase of $4.15 million, based on a cost of equity of 9.1% and a capital structure of 52% equity and 48% debt. The Settling Parties agree that this distribution revenue increase shall be implemented for all services rendered on and after July 1, 2020.

Except for the specific items discussed below, the Settling Parties agree that the $4.15 million distribution revenue increase represents a reasonable compromise of all issues relating to the revenue requirement pending before the Commission for the purpose of permanent rates. As the sum expressed above is the result of compromise and settlement, it is a liquidation of all revenue requirement issues. The Settling Parties agree that the revenue requirement recommended to the Commission in this Agreement results in permanent rates for Liberty's customers that are just and reasonable. The permanent rate increase described in this Section A shall be reconcilable to the effective date of temporary rates in this case, July 1, 2019, per Order No. 26,267, in accordance with Section II. D below.

Salem Investments. The Settling Parties acknowledge that, based on the record in this case, there is not agreement that Liberty's proposed investments in the Salem area, as described in Liberty's Initial Testimony filed April 30, 2019, at Bates II-186 through II-189 and II-197 (most notably a new Rockingham substation and a new 115 kV transmission line from Golden Rock substation to Rockingham substation), constitute a prudent solution for serving current and future Salem area load. Accordingly, the Settling Parties agree that consensus on the cost recovery and rates approved in this case (including rate base treatment of historic capital investments in the rates effective July 1, 2020, and the plan for three step adjustments for post-test year investments effective in 2020, 2021, and 2022) will not be used to support a position in any future proceeding that additional investments in Salem (including, but not limited to, the Rockingham Substation and 115kV transmission line) were prudent. Further, nothing in this Agreement shall preclude any party in a future proceeding from arguing that Salem area investments for which rate recovery is not provided for in this Agreement (both investments made as of the date of this Agreement and not yet closed to plant and investments not yet made) should not be recovered from customers.

B. Step Increases

The Company shall be permitted to recover additional annual revenue in the form of three step increases for certain capital additions in service as of December 31, 2019, December 31, 2020, and December 31, 2021 (the third step increase being subject to certain conditions, as described in this Section), each step being subject to Commission approval.

The Company shall be permitted to recover approximately $1.4 million in additional annual revenue in the form of a step increase in rates for capital additions in service as of December 31, 2019, as shown in Attachment 1. Following the process described below, this first step increase shall take effect for all service rendered on and after July 1, 2020, and shall be recovered through rate adjustments as described in Section II.F.

The Company shall be permitted to recover approximately $1.8 million in additional annual revenue in the form of a second step increase in rates for capital additions in service as of December 31, 2020, as shown in Attachment 2, following the process described below. This second step increase shall take effect for all service rendered on and after July 1, 2021, and shall be recovered through rate adjustments as described in Section II.F. Liberty reserves the right to substitute projects into Attachment 2 so long as any new projects are not growth projects and are not related to the Rockingham Substation or the 115kV transmission line.

Assuming the conditions described below are met, the Company shall be permitted to recover no more than $1.8 million in additional annual revenue in the form of a third step increase in rates for 2021 capital additions in service as of December 31, 2021. With its April 6, 2021, step adjustment filing, Liberty shall provide a list of 2021 capital additions planned to be in service by December 31, 2021, and planned to be submitted for recovery in the third step increase effective July 1, 2022. Such 2021 capital additions shall be similar in nature to the 2019 and 2020 additions listed on Attachments 1 and 2 and shall not include growth related additions. This third step increase shall take effect for all services rendered on and after July 1, 2022, and shall be recovered through rate adjustments as described in Section II.F.

To implement the step increases, the Company shall make a filing by May 26, 2020, for the first step increase; on April 6, 2021, for the second step increase; and on April 6, 2022, for the third step increase. In these filings, Liberty shall provide the amount of the investments to be included in the step increases (by project) and detailed project descriptions including the initial budget, the final cost, and the date each project was booked to plant in-service. In addition, for each project Liberty shall provide all Company project documents including, but not limited to, Business Cases, Capital Project Expenditure Applications, Change Order Forms, Project Close Out Reports, and work orders. Staff may request additional information after reviewing the initial filings. The Company shall propose a rate increase effective July 1 of the filing year to recover the revenue requirement associated with each step adjustment.

For all three step increases, if the actual cost of the capital additions is less than the budgeted amounts, the actual amounts shall be used to calculate the step adjustments. If the actual cost of the capital additions exceeds the budgeted amounts, the Company may seek recovery of the excess through this step adjustment process (except that the third step increase is capped at a $1.8 million rate increase). The Company may otherwise seek recovery in its next rate case for any above-budget investments not approved in a step adjustment described here. The revenue requirement for the step adjustments will be calculated in a manner similar to that used in the Company's filing seeking approval of the first step adjustment.

The Settling Parties ask the Commission hold a hearing prior to the proposed July 1 effective dates of each step increase to review and approve the proposed step increases.

C. Performance Based Ratemaking

The Settling Parties stipulate and agree that it is in the public interest for Liberty to explore transitioning away from the strict application of traditional cost-of-service ratemaking principles in favor of a performance-based ratemaking ("PBR") approach. For purposes of this paragraph, "performance-based ratemaking" means a process of defining regulatory goals, specifying outcomes toward the achievement of those goals, applying performance metrics that measure such achievement, and establishing revenue adjustment mechanisms that support safe and reliable utility service, while rewarding utility shareholders for the achievement of performance metric benchmarks and penalizing them for failing to achieve such benchmarks. Therefore, as a prerequisite to obtaining approval of the third step increase the Company shall: (1) present proposals to Staff, the OCA, and NHDES for PBR mechanism(s) for inclusion in its next distribution rate case through meetings or technical sessions commenced at least nine months prior to the April 6, 2022, step increase filing; and (2) in good faith consider the comments of Staff and the OCA in determining the details of the PBR mechanisms before finalizing and proposing them in the next distribution rate filing.

D. Effective Date for Permanent Rates and Recoupment

The permanent rate increase agreed to in Section II.A shall be effective for all service rendered on and after July 1, 2020.

The difference between the distribution revenues obtained from the rates prescribed in the temporary rate order, Order No. 26,267, and the distribution revenues that would have been obtained under the rates finally determined after review and approval of this Agreement, if applied during the period that the temporary rate order was in effect, shall be recovered from customers over a period of twenty-four months beginning with service rendered as of July 1, 2020. The total estimated amount of recoupment is $1,835,991, as shown on Attachment 3, and shall be recovered through a uniform percentage change to all rates and charges, excluding the customer charges for domestic service rates. The estimated amount of recoupment has been calculated using actual billing data for July 2019 through February 2020, and estimated billing data for March through June 2020. Any difference between the actual recoupment amount and the estimated amount shown on Attachment 3 will be reconciled and adjusted once as part of the July 1, 2021, step adjustment, and the adjusted recoupment rate will remain in effect until June 30, 2022, at which time the annual distribution rate level shall be decreased accordingly.

E. Rate Case Expenses

Subject to Staff audit and adjustment for the difference between estimated and actual expense, the Company shall recover $553,641.81[1] in rate case expenses commencing on July 1, 2020, as shown on Attachment 4. The Company agrees to submit by June 15, 2020, an accounting of its rate case expenses, with appropriate supporting documentation, for review by Staff and the OCA and subsequent approval by the Commission. The Company shall recover its

[1] This figure includes the rate case expenses incurred and anticipated as of April 28, 2020. Recovery of any additional rate case expenses submitted after that date will be addressed as part of a step adjustment review.

just and reasonably incurred rate case expenses in the same manner as it recovers the temporary rate recoupment. Staff shall provide its recommendation for rate case expense recovery to the parties as soon as reasonably possible, and the Company shall be authorized to recover the approved rate case expenses beginning with service rendered as of July 1, 2020. Once the final amount of actual, just and reasonable rate case expenses is determined, any difference between the amount recovered commencing July 1, 2020, and the final amount shall be recovered commencing July 1, 2021 (to coincide with the second step rate change). Rate case expenses shall be recovered through an increase to the annual distribution rate level effective July 1, 2020, and adjusted for final costs effective July 1, 2021, and the adjusted increase will remain in effect until June 30, 2022, at which time the annual distribution rate level shall be decreased accordingly.

F. Rates and Rate Design

The total increase effective July 1, 2020, for permanent rates is $4,150,000 above the annual revenue level in effect on June 1, 2019 (prior to implementation of temporary rates), is $2,056,651 above the annual revenue level in effect after implementation of temporary rates, and shall result in a 10.5% increase above the distribution revenues in effect June 1, 2019, and a 5.1% increase above the temporary rates. Permanent bill impacts for typical customers are included in Attachment 5.

The rates and charges for effect on July 1, 2020, including the effect of recoupment and recovery of rate case expense, are shown on Attachment 6.

The rate design shall remain as currently charged under the temporary rates approved by Order No. 26,267. In the calculation of all rate adjustments described in this Agreement, each class shall receive the same overall percentage increase to its share of distribution revenue and all rate changes authorized under this Agreement shall be recovered through a uniform percentage change to all rates and charges, excluding the customer charges for domestic service rates.

1. Domestic Service Rates D, D-10, D-11, T, and Rate EV

The customer charge for Rates D, D-10, D-11, and T shall be $14.74 per month. The customer charge for Rate EV shall be $11.35 per month. The difference between the total class revenue increase and the amount of revenue to be recovered through the customer charge shall be recovered through kilowatt-hour (kWh) charges for retail delivery service. The customer charge shall remain at this level in the subsequent distribution rate changes provided for in this Agreement (i.e., the three step adjustments, the rate case expense reconciliation, and the REP filing).

2. Rates G-3, V, G-1, G-2, M, LED-1, and LED-2

Rates and charges under Rates G-3, V, G-1, and G-2 shall be increased by a uniform percentage. Rates M and LED-1 will be increased as shown in Attachment 5, page 7, as result of the permanent rate increase. For purposes of recoupment and rate case expenses, a uniform percentage increase will be applied to Rates M, LED-1, and LED 2 as shown in Attachment 6. For all future rate changes under this agreement, Rates M, LED-1, and LED-2 will be subject to the same percentage changes as the other rate classes.

3. Future Rate Design

Liberty agrees that it shall develop an Advanced Rate Design Road Map, which shall include but not be limited to (1) an explanation of how Liberty plans to leverage the functionality of its existing and planned investments, particularly meters, to maximize ratepayer benefits, and (2) Liberty's plans for the future of rates for each customer class, including the extent to which the utility plans to rely on innovative rate design techniques such as time-of-use rates, critical peak pricing, etc. For each customer class, Liberty shall specify the general design characteristics (e.g., number of time periods, number of hours within each period, and pricing ratios between each period) and the investment needed to enable the rate design, the associated timeline and the nature of the rollout (e.g., opt-out versus optional rate designs). Liberty shall submit the Advanced Rate Design Roadmap to Commission Staff, the OCA, the City, CENH, and NHDES at least nine months prior to the April 6, 2022, step increase filing, shall discuss the plan in good faith, and shall thereafter include the plan in its next filed Least-Cost Integrated Resource plan or Integrated Distribution Plan filed in connection with or arising out of the Commission's grid modernization proceeding (IR 15-296), and the Company's next rate case, as appropriate.

G. Reliability Enhancement Program/Vegetation Management Program ("REP" and "VMP")

1. <u>REP</u>

The REP shall terminate with the final order in the "Calendar Year 2020 Annual Report and Reconciliation and Rate Adjustment Filing," docket, which will seek recovery of REP investments made during the 2020 construction season. Staff and the OCA accept the 2020 REP capital budget, Attachment 7, as presented during the February 6, 2020, REP/VMP meeting. This termination of the REP shall not bar the Company from proposing a PBR mechanism that is similar to the REP for discussion prior to its next distribution rate proceeding, as described in Section II.C above.

The 2021 rate increase to recover 2020 REP costs shall be applied as described in Section II.F.

2. VMP

Under the VMP, the Company shall maintain a four-year cycle for tree trimming and vegetation management and shall continue with the filings and reporting requirements currently in place. The base rate increase agreed to in this Agreement includes an increase in the VMP spending to $2,200,000 for 2020, which shall continue until changed in a future base rate case. The Company shall not recover any VMP expenses that exceed 10% of that amount, or in excess of $2,420,000, through the annual reconciliation filing, or otherwise. The VMP spending shall be reconciled each year, with any under spending carried into the next program year or returned to customers, as determined by the Commission.

H. Planning Criteria

Beginning with projects to be put into service after December 31, 2020, the Company shall follow the planning criteria contained in the Distribution Planning Criteria and Strategy document, Attachment 8.

I. Decoupling

Liberty shall implement a decoupling mechanism effective July 1, 2021.

In return for Liberty agreeing to a later date to implement decoupling, the parties agree that Liberty shall be permitted to continue the Lost Revenue Adjustment Mechanism (LRAM) for calendar years 2019 and 2020. Final determination of the LRAM and SBC for billing will be made in DE 17-136, or subsequent energy efficiency dockets. The Settling Parties shall review and approve tariff language implementing the decoupling mechanism prior to Liberty's submission of the decoupling tariff to the Commission in sufficient time for the scheduled July 1, 2021, implementation.

The Company will make a reconciliation filing by September 1 following the completion of each decoupling year (July 1 to June 30), in which Liberty will calculate the rate increase or rate refund arising from the just completed decoupling year, and request approval for any adjustment to go into effect on November 1 for the following twelve months.

Prior to the Year 1 decoupling filing of September 1, 2022, the Settling Parties shall informally discuss the preliminary reconciliation calculation of the July 1, 2021, to June 30, 2022 (Year 1) decoupling year and attempt in good faith to reach agreement as to the treatment of any atypical consequences flowing from the COVID-19 pandemic. If an agreement is reached, the Company will present that agreement to the Commission as part of the Company's September 1, 2022, filing for consideration and approval. If an agreement cannot be reached, the Settling Parties have the option to file testimony or technical statements by September 1, 2022, in conjunction with the Company's decoupling filing, presenting their preferred method for handling the impact on decoupling of COVID-19. The Settling Parties agree that the extent of recovery of COVID 19 impacts through decoupling adjustments may be impacted by any other means or mechanisms the Commission may establish for addressing COVID 19 impacts.

The decoupling mechanism will be implemented as described in the Company's original filing, with the following amendments:

1) There shall be a 3% cap on the amount refunded or charged to customers. The 3% cap shall be equal to 0.03 times the allowed revenue requirement subject to annual adjustments as shown in the Revenue Subject to Decoupling page of Attachment 9. The decoupling amount will be recovered or refunded during the following year up to the 3% cap. Any amounts in excess of the 3% cap will be deferred and recovered or refunded in future periods, as determined by the Commission. Any amounts deferred will be added to the aggregate decoupling adjustment amount of the following periods until recovered or refunded such that there is a maximum adjustment of 3% refunded or charged each year.

2) Any over- or under-collection shall carry interest at the prime rate.

3) The amounts to be refunded or collected under this decoupling mechanism shall be calculated annually using monthly accruals. These monthly accruals will be summed for each decoupling year and presented in the annual reconciliation filing. Monthly decoupling accruals are calculated as follows:

   a) As shown in the Monthly Decoupling Calculation page of Attachment 9, the monthly target revenues per customer ("Monthly Target RPC") amounts will be determined for each of the Company's rate classes by:

      i) allocating each years' allowed revenue requirement to each rate class, by month, in proportion to the test year with the following exceptions:

         (1) Rate classes M, LED-1, and LED-2 will not be included in the decoupling calculations;

         (2) Rate classes D-11 and EV, will not be included in the decoupling calculations as they are new rate classes. The inclusion of those rate classes will be reevaluated in the next rate case; and

      ii) dividing each class monthly target revenue number by the number of monthly customer bills from the test year.

   b) Monthly Actual RPC will be calculated as the actual monthly revenues by rate class divided by the actual number of bills for each rate class rendered during that month.

   c) The Monthly Actual RPC will be compared to the Monthly Target RPC for each rate class. The difference between the Monthly Actual RPC and the Monthly Target RPC for each rate class will then be multiplied times the actual number of bills rendered for each rate class to determine the monthly revenue shortfall/surplus for each class, the sum of which will constitute the total monthly revenue shortfall/surplus.

   d) At the end of the reconciliation period, the monthly amounts will be summed to determine the cumulative annual revenue shortfall/surplus.

   e) Subject to the cap described above, the Annual Allowed Adjustment revenue shortfall/surplus, will be allocated to the classes using the Rate Class Allocation identified on the Decoupling Sensitivity Example page of Attachment 9 which corresponds to the class revenue apportionment of the distribution revenue requirement contained in this Agreement, as detailed on Line 115 of Attachment 5, page 4.

f) The amount allocated to each rate class will be allocated to the kWh and kW rate adjustments for each class on the basis of the actual kWh and kW's of the decoupling year.

Attachment 9 is an illustration of the above decoupling calculation, using estimated amounts. The Settling Parties agree that the dollar amounts in Attachment 9 do not embody any party's projections or proposals.

J. Tariff Provisions

The Company's initial filing sought approval of Tariff No. 21, replacing existing Tariff No. 20. The Settling Parties recommend that the Commission approve a revised version of proposed Tariff No. 21, Attachment 10, which contains the increased rates and charges effective July 1, 2020 as provided for in this Settlement, a number of minor edits and the following modifications and additions to Tariff No. 20:

1. EV Tariff

The Company shall implement the EV tariff as it appears in the proposed Tariff No. 21, Attachment 10, and shall report the following information to the Commission by November 6 of each year: (1) the number of customers taking service under the EV tariff; and (2) the aggregated usage data, by TOU period, by month, for those customers.

2. LED – Outdoor Lighting tariffs.

The Company shall implement the LED-Outdoor lighting tariffs as they appear in the proposed Tariff No. 21, Attachment 10.

3. Interconnection fees.

Liberty shall adopt the following table to charge for interconnection fees. The structure will remain in place until a future adoption of interconnection fees is approved.

Project Size (Max AC Rating of Inverters)	Supplemental Review Fee
>10 kW to 30 kW	$125
>30 kW to 50 kW	$500
>50 kW to 100 kW	$1000

K. Lead/Lag Days

The net lead/lag days shall be 24.2 days or 6.63%. See Attachment 11 for the supporting calculations.

L. Depreciation Reserve Imbalance

The depreciation reserve imbalance is a deficiency of $1,399,800 determined using plant balances as of December 31, 2018. The Company shall amortize this depreciation reserve imbalance over a period of 6 years, beginning on July 1, 2020.

M. Depreciation

The depreciation rates shown on Attachment 12 shall be used by Liberty at least until the Commission issues a final order in its next base distribution rate case.

N. Pole Attachment Fees

The Settling Parties agree that the Company will update its fees once per year in accordance with the Puc 1300 rules.

O. Next Distribution Rate Case

The test year for the Company's next general distribution rate case shall be no sooner than the twelve-month period ending December 31, 2022.

P. Reporting Requirements

Staff, OCA, and the Company agree to meet by August 31, 2020, to review the list of the Company's current reporting requirements to determine potential eliminations, consolidations, decreased frequency, revised reporting deadlines, and similar changes. Some or all of such changes may be subject to Commission approval.

Q. IEEE 1547-2018

In April 2018, the Institute of Electrical and Electronics Engineers (IEEE) published a major revision of the national standard for the grid interconnection of distributed energy resources (DERs), IEEE 1547-2018, which requires DERs to include certain specific functionalities (including but not limited to voltage support, frequency ride-through, voltage regulation, and frequency regulation) that support the reliability of the grid and improve power quality. The parties acknowledge that such capabilities have the potential to increase the amount of DERs that distribution utilities, including Liberty, can accommodate and that, for DERs which interconnect via inverters, so-called "smart" inverters are the basis for compliance with IEEE 1547-2018. The parties further acknowledge that IEEE 2018-1547 lays out a set of options for deployment, based on default settings and potential departures from those settings, including, e.g., activation of the "volt-VAR" and "volt-watt" modes of smart inverters. In light of the complexity of these determinations, and their importance for customers exporting energy to the grid via smart inverters, the Settling Parties agree to participate in a collaborative process overseen by the Commission Staff to ascertain the most beneficial default smart inverter settings under IEEE 1547-2018. A goal of this collaboration shall be to report out of this process with its recommendations by December 31, 2021. The Settling Parties agree that this collaborative process may be undertaken on a utility-specific basis or as a single process applicable to all three of the state's investor-owned electric distribution utilities.

III. EXOGENOUS EVENTS

A. Liberty may, subject to review and approval of the Commission, adjust distribution rates upward or downward resulting from Exogenous Events, as defined and described below.

B. To the extent that the revenue impact of such event is not otherwise captured through another rate mechanism that has been approved by the Commission, for any singular (not collective) event defined as a State Initiated Cost Change, Federally Initiated Cost Change, Regulatory Cost Reassignment, or Externally Imposed Accounting Rule Change, Liberty may adjust distribution rates upward, and shall adjust distribution rates downward if the total distribution revenue impact (positive or negative) of such event exceeds $150,000 (Exogenous Events Rate Adjustment Threshold) for calendar years 2020 and 2021.

1. "State Initiated Cost Change" shall mean any externally imposed changes in state or local law or regulatory mandates or changes in other precedents governing income, revenue, sales, franchise, or property or any new or amended regional, state or locally imposed fees (but excluding the effects of routine annual changes in municipal, county and state property tax rates and revaluations), which impose new or expanded obligations, duties or undertakings, or remove existing obligations, duties or undertakings, and which individually decrease or increase Liberty's distribution costs, revenue, or revenue requirement.

2. “Federally Initiated Cost Change” shall mean any externally imposed changes in the federal tax rates, laws, regulations, or precedents governing income, revenue, or sales taxes or any changes in federally imposed fees, which impose new or expanded obligations, duties or undertakings, or remove existing obligations, duties or undertakings, and which individually decrease or increase Liberty's distribution costs, revenue, or revenue requirement.
3. Regulatory Cost Reassignment: The distribution revenue changes described in this Paragraph B are based on the separation of costs among generation, transmission, and distribution functions of Liberty in place on the date of this Agreement.
4. “Regulatory Cost Reassignment” shall mean the reassignment of costs and/or revenues now included in the generation, transmission, or distribution functions to or away from the distribution function by the Commission or the Federal Energy Regulatory Commission.
5. “Externally Imposed Accounting Rule Change” shall be deemed to have occurred if the Financial Accounting Standards Board or the Securities and Exchange Commission adopts a rule that requires utilities to use a new accounting rule that is not being utilized by Liberty as of January 1, 2020.

C. No later than the last day of February of 2021 and 2022, Liberty shall file with the Commission, Staff, and OCA a Certification of Exogenous Events for the prior calendar year. If in the prior calendar year Liberty incurs any changes in distribution costs, revenue, or revenue requirement in excess of the Exogenous Events Rate Adjustment Threshold in connection with any Exogenous Event as defined in

Paragraph B, Liberty shall provide specific and sufficient detail supporting each change and the Exogenous Event(s) associated with each change for the Commission, Staff, and OCA to assess the proposed Exogenous Event rate adjustment. If no Exogenous Events causing changes in excess of the Exogenous Events Rate Adjustment Threshold occurred during the prior calendar year, Liberty shall certify that fact in its annual Certification of Exogenous Events. On or before March 31 of 2021 and 2022, the Staff and the OCA may make a filing requesting an Exogenous Event rate decrease or contesting an Exogenous Event rate increase proposed by Liberty. Any adjustments to Liberty's revenue requirement for Exogenous Events shall be subject to review and approval as deemed necessary by the Commission, and shall be implemented for service rendered on or after May 1 of that year. Any such filings are limited to one per calendar year, provided that any costs incurred or saved due to such Exogenous Events shall be deferred for consolidation in the single filing.

D. Any Exogenous Event adjustment made pursuant to this Agreement will remain in rates only until the effective date of new rates determined in the Company's next distribution base rate proceeding.

IV. CONDITIONS

Nothing in this Agreement prevents the Company from recovering any COVID-19 related costs that the Commission may allow in a future proceeding.

This Agreement is expressly conditioned on the Commission's acceptance of all its terms, without change or condition. If the Commission does not accept this Agreement in its entirety, without change or condition, or if the Commission makes any findings that go beyond the scope of this Agreement, and any of the Settling Parties notify the Commission within five business days of their disagreement with any such changes, conditions, or findings, the

Agreement shall be deemed to be withdrawn, in which event it shall be deemed to be null and void and without effect, shall not constitute any part of the record in this proceeding, and shall not be relied on by Staff or any party to this proceeding or by the Commission for any other purpose.

The Settling Parties agree that the Commission's approval of this Agreement will not constitute continuing approval of, or precedent for, any particular principle or issue, but such acceptance does constitute a determination that the adjustments and provisions stated in their totality are just and reasonable and consistent with the public interest and that the revenues contemplated will be just and reasonable under the circumstances.

The discussions that produced this Agreement have been conducted on the understanding that all offers of settlement and settlement discussions relating to this docket shall be confidential, shall not be admissible as evidence in this proceeding, shall be without prejudice to the position of any party or participant representing any such offer or participating in any such discussion, and are not to be used in connection with any future proceeding or otherwise.

The information and testimony previously provided in this proceeding are not expected to be subject to cross-examination by the Settling Parties, which would normally occur in a fully litigated case. The Settling Parties agree that all direct and rebuttal testimony and supporting documentation should be admitted as full exhibits for purposes of reviewing this Agreement. The Settling Parties' agreement to admit all testimony without challenge does not constitute agreement by the Settling Parties that the content of the written testimony is accurate or what weight, if any, should be given to the views of any witness. The identification of the resolution of any specific issue in this Agreement does not indicate any of the Settling Parties' agreement to that resolution for purposes of any future proceeding, nor does the reference to any other document bind the Settling Parties to the contents of, or recommendations in, that document for purposes of any future proceeding. The Commission's approval of the recommendations in this Agreement shall not constitute a determination or precedent with regard to any specific adjustments, but rather shall constitute only a determination that the revenue requirement and rates resulting from, and other specific conditions stated in this Agreement are just and reasonable. The Settling Parties agree to forego cross-examining witnesses regarding their pre-filed testimony and, therefore, the admission into evidence of any witness's testimony or supporting documentation shall not be deemed in any respect to constitute an admission by any party to this Agreement that any allegation or contention in this proceeding is true or false, except that the sworn testimony of any witness shall constitute an admission by such witness.

This Agreement may be executed by facsimile and in counterparts, each of which shall be deemed to be an original, and all of which, taken together, shall constitute one agreement binding on all Settling Parties.

[S*ignature page follows*]

Dated: May 22, 2020

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

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By its Attorney, Michael J. Sheehan

Dated: May __, 2020

Staff of the New Hampshire Public Utilities Commission

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By its Attorney, Paul B. Dexter

Dated: May __, 2020

Office of the Consumer Advocate

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By the Consumer Advocate, D. Maurice Kreis

Dated: May __, 2020

City of Lebanon

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By Clifton Below, Assistant Mayor, duly authorized

Dated: May __, 2020

Clean Energy New Hampshire

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By its Attorney, Elijah D. Emerson

Dated: May __, 2020	Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ______________________________ By its Attorney, Michael J. Sheehan
Dated: May 21, 2020	Staff of the New Hampshire Public Utilities Commission ______________________________ By its Attorney, Paul B. Dexter
Dated: May __, 2020	Office of the Consumer Advocate ______________________________ By the Consumer Advocate, D. Maurice Kreis
Dated: May __, 2020	City of Lebanon ______________________________ By Clifton Below, Assistant Mayor, duly authorized
Dated: May __, 2020	Clean Energy New Hampshire ______________________________ By its Attorney, Elijah D. Emerson

Dated: May __, 2020	Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
	______________________________ By its Attorney, Michael J. Sheehan
Dated: May __, 2020	Staff of the New Hampshire Public Utilities Commission
	______________________________ By its Attorney, Paul B. Dexter
Dated: May 21, 2020	Office of the Consumer Advocate
	______________________________ By the Consumer Advocate, D. Maurice Kreis
Dated: May __, 2020	City of Lebanon
	______________________________ By Clifton Below, Assistant Mayor, duly authorized
Dated: May __, 2020	Clean Energy New Hampshire
	______________________________ By its Attorney, Elijah D. Emerson

Dated: May __, 2020

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

____

By its Attorney, Michael J. Sheehan

Dated: May __, 2020

Staff of the New Hampshire Public Utilities Commission

____

By its Attorney, Paul B. Dexter

Dated: May __, 2020

Office of the Consumer Advocate

____

By the Consumer Advocate, D. Maurice Kreis

Dated: May 22, 2020

City of Lebanon

DocuSigned by:

Clifton Below

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By Clifton Below, Assistant Mayor, duly authorized

Dated: May __, 2020

Clean Energy New Hampshire

____

By its Attorney, Elijah D. Emerson

Dated: May __, 2020

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

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By its Attorney, Michael J. Sheehan

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By its Attorney, Paul B. Dexter

Dated: May __, 2020

Office of the Consumer Advocate

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By the Consumer Advocate, D. Maurice Kreis

Dated: May __, 2020

City of Lebanon

____
By Clifton Below, Assistant Mayor, duly authorized

Dated: May 15, 2020

Clean Energy New Hampshire

____
By its Attorney, Elijah D. Emerson

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Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
Computation of Revenue Requirement
CY 2019

			CY 2019		
1	Total Investment		$ 8,761,603		
2					
3	**Deferred Tax Calculation**				
4	Book Depreciation Rate		3.36%		
5	Federal Tax Depreciation Rate		3.75%		
6	FEDERAL Vintage Year Tax Depreciation:				
7	CY Spend		$328,560		
8	Annual Tax Depreciation		$328,560		
9					
10	STATE Vintage Year Tax Depreciation:				
11	CY Spend		$328,560		
12	Annual Tax Depreciation		$328,560		
13					
14	Book Depreciation		$293,993		
15					
16	Book/Tax Timer (Federal)				
17	less: Deferred Tax Reserve (State)		$2,662		
18	Net Book/Tax Timer (Federal)		$31,906		
19	Effective Tax Rate (Federal)		21.00%		
20	Deferred Tax Reserve (Federal)		$6,700		
21	Book/Tax Timer (State)		$34,568		
22	Effective Tax Rate (State)		7.70%		
23	Deferred Tax Reserve (State)		$2,662		
24	TOTAL Deferred Tax Reserve		$9,362		
25					
26	**Rate Base Calculation**				
27	Plant In Service		$8,761,603		
28	Accumulated Book Depreciation		($293,993)		
29	Deferred Tax Reserve		($9,362)		
30	Year End Rate Base		$8,458,249		
31					
32	**Revenue Requirement Calculation**				
33	Year End Rate Base		$8,458,249		
34	Pre-Tax ROR		9.36%		
35	Return and Taxes		$791,284		
36	Book Depreciation		$293,993		
37	Property Taxes	3.12%	$264,189		
38	Annual Revenue Requirement		$1,349,466		
39					
40	Adjusted Annual Revenue Requirement		$1,349,466		
41					
42					
43	**Imputed Capital Structure**			Weighted	
44		Ratio	Rate	Rate	Pre Tax
45	Long Term Debt	48.00%	5.97%	2.87%	2.87%
46	Common Equity	52.00%	9.10%	4.73%	6.49%
47					
48		100.00%		7.60%	9.36%

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Project List
In Service as of December 31, 2019

2019 Project #	Project Description	Priority	Total Spend[1]	In Service	FERC	Book Rate	Book Amt	MACRS	Tax Amt
8830-1911	GSE-Dist-Public Require Blanket	2. Mandated	$431,329	Various - 2019	364	3.64%	$ 15,700	3.75%	$ 16,175
8830-1912	Dist-Damage&Failure Blanket	2. Mandated	$1,184,186	Various - 2019	364	3.64%	$ 43,104	3.75%	$ 44,407
8830-C18630	Charlestown Dsub	4. Regulatory	($92,766)	11/9/2017	362	3.00%	$ (2,783)	3.75%	$ (3,479)
8830-1929	Walk in Center Relocation Salem	5. Discretionary	$567,737	10/1/2019	390	1.62%	$ 9,197	3.75%	$ 21,290
8830-1944	Golden Rock Substation	3. Growth	$2,012,483	12/4/2019	362	3.00%	$ 60,374	3.75%	$ 75,468
8830-1945	Golden Rock Distribution Feeder 19L2	3. Growth	$522,516	12/4/2019	364	3.64%	$ 19,020	3.75%	$ 19,594
8830-1951	Enhanced Bare Conductor Replacement	5. Discretionary	$1,060,252	10/30/2019	364	3.64%	$ 38,593	3.75%	$ 39,759
8830-1958	Install Service to Tuscan Village South Line	3. Growth	$803,676	11/20/2019	369	3.89%	$ 31,263	3.75%	$ 30,138
8830-1959	Golden Rock Distribution Feeder 19L4	3. Growth	$393,123	12/4/2019	362	3.00%	$ 11,794	3.75%	$ 14,742
8830-1960	Golden Rock Underground	4. Regulatory	$412,763	12/4/2019	364	3.64%	$ 15,025	3.75%	$ 15,479
8830-1991	Granite St Meter Purchases	2. Mandated	$952,029	Various - 2019	364	3.64%	$ 34,654	3.75%	$ 35,701
8830-1992	Granite St Transformer Purchases	2. Mandated	$514,275	Various - 2019	368	3.51%	$ 18,051	3.75%	$ 19,285
		Total	$8,761,603				$ 293,993		$ 328,560
							3.36%		3.75%

[1] Projects that span multiple years may have a 2019 actual spend lower than the total project spend reported in the related Project Close-out Reports. Liberty will provide a breakdown of annual charges by project in each of the three step adjustment filings. The amounts shown here were provided by Liberty and are subject to review and Commission approval in the three individual step adjustment dockets.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
Computation of Revenue Requirement
CY 2020

			CY 2020
1	Total Investment		$ 11,135,000
2			
3	**Deferred Tax Calculation**		
4	Book Depreciation Rate		4.04%
5	Federal Tax Depreciation Rate		3.75%
6	FEDERAL Vintage Year Tax Depreciation:		
7	CY Spend		$417,563
8	Annual Tax Depreciation		$417,563
9			
10	STATE Vintage Year Tax Depreciation:		
11	CY Spend		$417,563
12	Annual Tax Depreciation		$417,563
13			
14	Book Depreciation		$450,222
15			
16	Book/Tax Timer (Federal)		($32,659)
17	less: Deferred Tax Reserve (State)		($2,515)
18	Net Book/Tax Timer (Federal)		($30,145)
19	Effective Tax Rate (Federal)		21.00%
20	Deferred Tax Reserve (Federal)		($6,330)
21	Book/Tax Timer (State)		($32,659)
22	Effective Tax Rate (State)		7.70%
23	Deferred Tax Reserve (State)		($2,515)
24	TOTAL Deferred Tax Reserve		($8,845)
25			
26	**Rate Base Calculation**		
27	Plant In Service		$11,135,000
28	Accumulated Book Depreciation		($450,222)
29	Deferred Tax Reserve		$8,845
30	Year End Rate Base		$10,693,623
31			
32	**Revenue Requirement Calculation**		
33	Year End Rate Base		$10,693,623
34	Pre-Tax ROR		9.36%
35	Return and Taxes		$1,000,407
36	Book Depreciation		$450,222
37	Property Taxes	3.12%	$333,365
38	Annual Revenue Requirement		$1,783,994
39			
40	Adjusted Annual Revenue Requirement		$1,783,994
41			
42			

				Weighted	
43	**Imputed Capital Structure**				
44		Ratio	Rate	Rate	Pre Tax
45	Long Term Debt	48.00%	5.97%	2.87%	2.87%
46	Common Equity	52.00%	9.10%	4.73%	6.49%
47					
48		100.00%		7.60%	9.36%

Granite State Electric
2020 Capital Step Adjustment

2020 Step

Project Description	Priority	Spend	FERC	Book Rate	Book Amt	MACRS	Tax Amt
GSE Backup Battery Program	4. Regulatory Programs	$ 1,500,000	371	10.00%	$150,000	14.29%	$214,350
Golden Rock Distribution Feeder 19L4	4. Regulatory Programs	$ 1,300,000	364	3.64%	$ 47,320	3.75%	$ 48,750
Main St Salem - Overhead Line Relocation	2. Mandated	$ 1,200,000	364	3.64%	$ 43,680	3.75%	$ 45,000
IE-NN URD Cable Replacement	5. Discretionary	$ 1,150,000	366	1.96%	$ 22,540	3.75%	$ 43,125
Dist-Damage&Failure Blanket	2. Mandated	$ 1,000,000	364	3.64%	$ 36,400	3.75%	$ 37,500
Install Service to Tuscan Village South Line	3. Growth	$ 900,000	364	3.64%	$ 32,760	3.75%	$ 33,750
Enhanced Bare Conductor Replacement	5. Discretionary	$ 875,000	364	3.64%	$ 31,850	3.75%	$ 32,813
01659 Granite St Meter Purchases	2. Mandated	$ 840,000	370	1.96%	$ 16,464	3.75%	$ 31,500
Golden Rock Substation	3. Growth	$ 650,000	362	3.00%	$ 19,500	3.75%	$ 24,375
01660 Granite St Transformer Purchases	2. Mandated	$ 600,000	368	3.51%	$ 21,060	3.75%	$ 22,500
GSE Facilities Capital Improvements	5. Discretionary	$ 600,000	390	1.62%	$ 9,720	3.75%	$ 22,500
GSE-Dist-Public Require Blanket	2. Mandated	$ 520,000	364	3.64%	$ 18,928	3.75%	$ 19,500
	Total	$11,135,000			$450,222		$575,663
					4.04%		5.17%

Docket No. DE 19-064
Settlement Agreement
Attachment 3

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Uitilities
Distribution increase due to Recoupment
Effective July 1, 2020 - June 30, 2022
Docket No. DE 19-064

1	Actual Billed Revenues July 2019 - February 2020	$28,169,453
2	Estimated Billed Revenues March 2020 - June 2020	$12,541,904
3		$40,711,357
4		
5	Calculated July 2019 - June 2020 Revenue @ DE 19-064 Settlement Agreement Rates	$42,547,348
6		
7	Recoupment (Line 5 - Line 3)	$1,835,991

Liberty Utilities (Granite State Electric) Corp.
Docket No. DE 19-064 Rate Case Expense
As of April 22, 2020

Service Provider	Expense to Date	Estimated Additional Expense	Total Estimated Expense	Description of Service
Alliance Consulting Group	$ 41,997.81	$ -	$ 41,997.81	Depreciation study, testimony, data responses
Concentric Energy Advisors	108,710.72	-	108,710.72	Marginal cost study, testimony, data responses
Concentric Energy Advisors	33,871.46	3,500.00	37,371.46	Decoupling, data responses
Concentric Energy Advisors	38,127.84	3,500.00	41,627.84	Rate calculations/rate design, testimony, data responses
FTI Consulting	59,210.00	-	59,210.00	Cost of capital testimony, data responses
Minuteman Press	1,767.53	-	1,767.53	Copying services
Valley News	-		-	Legal Notices
Eagle Tribune	1,757.70	-	1,757.70	Legal Notices
Court Reporter	898.00	500.00	1,398.00	
Customer Notice	21,051.55	-	21,051.55	Per May 17, 2019, Secretarial Letter
Supplies	246.83	-	246.83	
DE 16-383 Rate Case Expenses	9,185.00	-	9,185.00	Order No. 26,139
Subtotal	$ 316,824.44	$ 7,500.00	$ 324,324.44	
Staff Consultants				
Blue Ridge Consulting	$ 60,447.50	$ -	60,447.50	Revenue Requirement
J. Randall Woolridge	-	29,000.00	29,000.00	Cost of Capital Testimony
Brattle Group	98,223.75	21,326.25	119,550.00	Marginal Cost of Service, Rate Design, Decoupling
			-	
OCA Consultants			-	
Bion Ostrander	-		-	Revenue Requirement
Strategen	20,319.87		20,319.87	
Subtotal PUC/OCA	$ 178,991.12	$ 50,326.25	$ 229,317.37	
Grand Total	$ 495,815.56	$ 57,826.25	$ 553,641.81	

Revenue Requirement Analysis

Normalized Distribution Revenue	$	39,560,962
Deficency	$	4,150,000
Target	$	43,710,962

Line		DOMESTIC SERVICE RATE D	DOMESTIC SERVICE Opt Peak Load Pricing RATE D-10	GENERAL SERVICE TIME-OF-USE RATE G-1	GENERAL LONG HOUR SERVICE RATE G-2	GENERAL SERVICE RATE G-3	OUTDOOR LIGHTING SERVICE RATE M	LIMITED TOTAL ELECTRICAL LIVING RATE T	LIMITED COMMERCIAL SPACE HEATING RATE V	Company Total
	(X)	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
1	A. Proforma Normalized Revenues at Current Rates									
2										
3	Company Total Distribution Base Revenues									
4	Distribution Revenues: Customer Charge Related	$ 5,922,891	$ 73,620	$ 603,077	$ 659,755	$ 949,162	$ -	$ 161,338	$ 2,945	$ 8,372,787
5	Revenues: Demand Charge Related	$ -	$ -	$ 7,157,573	$ 3,978,450	$ -	$ -	$ -	$ -	$ 11,136,023
6	Revenues: Energy Charge Related	$ 12,971,097	$ 208,919	$ 1,146,695	$ 288,587	$ 3,895,574	$ -	$ 590,748	$ 14,932	$ 19,116,552
7	Revenues: Misc Charges and Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Outdoor Light Fixtures	$ -	$ -	$ -	$ -	$ -	$ 935,600	$ -	$ -	$ 935,600
9	Company Total Base Revenues	$ 18,893,988	$ 282,539	$ 8,907,345	$ 4,926,792	$ 4,844,736	$ 935,600	$ 752,086	$ 17,877	$ 39,560,962
10	B. Billing Determinants									
11	Customer Bill Count									
12	Customers (Bills)	424,580	5,277	1,658	10,882	68,040	0	11,565	211	522,214
13	Energy Consumption (KWh)									
14	Distribution Quantity	0	0	0	147,993,116	88,095,304	3,277,030	15,352,073	328,389	255,045,912
15	Distribution Quantity Block 1	95,969,225	0	0	0	0	0	0	0	95,969,225
16	Distribution Quantity Block 2	180,071,056	0	0	0	0	0	0	0	180,071,056
17	Distribution Quantity On Peak	0	2,037,588	166,678,890	0	0	0	0	0	168,716,478
18	Distribution Quantity Off Peak	0	3,591,661	212,506,102	0	0	0	0	0	216,097,763
19	Distribution Farm	894,780	0	0	0	0	0	0	0	894,780
20	Distribution Quantity 6 hour control	769,373	0	0	0	0	0	0	0	769,373
21	Distribution Quantity 16 hour control	1,120,448	0	0	0	0	0	0	0	1,120,448
22	TOTAL Distribution Consumption (kWh)	278,824,882	5,629,249	379,184,992	147,993,116	88,095,304	3,277,030	15,352,073	328,389	918,685,035
23	Demand (kW)									
24	Billing Demand	0	0	951,328	510,109	0	0	0	0	1,461,437
25	Distribution Demand Optional Billing ($)	$ -	$ -	$ 144,424	$ 30,771	$ -	$ -	$ -	$ -	$ 175,195
26	High Voltage Delivery (kW)	0	0	354,348	1,949	0	0	0	0	356,297
27	High Voltage Metering Adjustment ($)	$ -	$ -	$ 8,641,165	$ 64,155	$ -	$ -	$ -	$ -	$ 8,705,320
28	C. CLASS REVENUE TARGETS									
29	Delivery Revenue Requirement									
30	Revenue Deficiency									4,150,000
31	Total Revenue Requirement									43,710,962
32	% Increase (Revenue Requirement - Normalized revenues)									10.49%
33		10.38%	10.38%	10.38%	10.38%	10.38%	15.00%	10.38%	10.38%	10.49%
34	FINAL BASE REVENUE TARGET	$20,855,357	$311,869	$9,832,009	$5,438,238	$5,347,665	$1,075,932	$830,160	$19,732	$43,710,962
35	D. RATE DESIGN									
36	Current Customer charge	$13.95	$13.95	$363.65	$60.63	$13.95		$13.95	$13.95	
37	Proposed Customer Charge	$14.67	$14.67	$401.79	$66.99	$15.41		$14.67	$15.41	
38	Customer Charge Revenue, Proposed Customer Charge									
39	Customer Revenues	$6,228,588	$77,419	$666,328	$728,962	$1,048,501		$169,666	$3,253	$8,922,717
40	Demand-Related Charges									
41	Current Demand Charge	$0.00	$0.00	$7.74	$7.79	$0.00		$0.00	$0.00	
42	Current High Voltage Delivery Credit	$0.00	$0.00	-$0.42	-$0.42	$0.00		$0.00	$0.00	
43	Optional Demand Surcharge ($)			0.20	0.20					
44	High Voltage Metering Adjustment (% x Applicable Charges)			-1.00%	-1.00%					
45	Demand-Related Billing Units									
46	Billing Demand (kW)	0	0	951,328	510,109	0		0	0	1,461,437
47	High Voltage Delivery Units	0	0	354,348	1,949	0		0	0	356,297
48	Optional Demand Surcharge ($)	$0	$0	$144,424	$30,771	$0		$0	$0	
49	High Voltage Metering Adjustment ($)	$0	$0	$8,641,165	$64,155	$0		$0	$0	
50	Proposed Demand-Related Charges									

Line		DOMESTIC SERVICE RATE D	DOMESTIC SERVICE Opt Peak Load Pricing RATE D-10	GENERAL SERVICE TIME-OF-USE RATE G-1	GENERAL LONG HOUR SERVICE RATE G-2	GENERAL SERVICE RATE G-3	OUTDOOR LIGHTING SERVICE RATE M	LIMITED TOTAL ELECTRICAL LIVING RATE T	LIMITED COMMERCIAL SPACE HEATING RATE V	Company Total
	(X)	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
51	Rate Class Increase	10.38%	10.38%	10.38%	10.38%	10.38%	15.00%	10.38%	10.38%	
52	Calculation of Demand-related charges									
53	Proposed Demand Charge	$0.00	$0.00	$8.54	$8.59	$0.00		$0.00	$0.00	
54	Proposed High Voltage Delivery Credit	$0.00	$0.00	-$0.46	-$0.46	$0.00		$0.00	$0.00	
55	Optional Demand Surcharge ($)			0.20	0.20					
56	High Voltage Metering Adjustment (% x Applicable Charges)			-1.00%	-1.00%					
57										
58	Demand Revenues at Proposed Rates	$0	$0	$7,903,256	$4,386,453	$0	$0	$0	$0	$12,289,710
59	Remaining Revenues	$14,626,769	$234,449	$1,262,424	$322,823	$4,299,164	$1,075,932	$660,494	$16,479	$22,498,535
60	Energy-related Revenue Target	$14,626,769	$234,449	$1,262,424	$322,823	$4,299,164	$122,987	$660,494	$16,479	$21,545,590
		12.76%	12.22%	10.09%	11.86%	10.36%		11.81%	10.36%	12.7%
61	Current Energy-Related Charges kWh									
62	Current Distribution Quantity $/kWh				$0.00195	$0.04422	$0.00000	$0.03848	$0.04547	
63	Current Distribution Quantity Block 1 $/kWh	$0.04657								
64	Current Distribution Quantity Block 2 $/kWh	$0.04657								
65	Current Distribution Quantity On Peak $/kWh		$0.10010	$0.00498						
66	Current Distribution Quantity Off Peak $/kWh		$0.00138	$0.00149						
67	Current Distribution Farm $/kWh	$0.04396								
68	Current Distribution Quantity 6 hour control $/kWh	$0.04096								
69	Current Distribution Quantity 16 hour control $/kWh	$0.04021								
70	Interruptible Credit 6 hour control ($ / Customer)	$0.00						$0.00		
71	Interruptible Credit 16 hour control ($ / Customer)	$0.00						$0.00		
72	Distribution Energy-Related Billing Units									
73	Distribution Quantity	0	0	0	147,993,116	88,095,304	3,277,030	15,352,073	328,389	255,045,912
74	Distribution Quantity Block 1	95,969,225	0	0	0	0	0	0	0	95,969,225
75	Distribution Quantity Block 2	180,071,056	0	0	0	0	0	0	0	180,071,056
76	Distribution Quantity On Peak	0	2,037,588	166,678,890	0	0	0	0	0	168,716,478
77	Distribution Quantity Off Peak	0	3,591,661	212,506,102	0	0	0	0	0	216,097,763
78	Distribution Farm	894,780	0	0	0	0	0	0	0	894,780
79	Distribution Quantity 6 hour control	769,373	0	0	0	0	0	0	0	769,373
80	Distribution Quantity 16 hour control	1,120,448	0	0	0	0	0	0	0	1,120,448
81	Interruptible Credit 6 hour control (Customers)	0	0	0	0	0	0	0	0	
82	Interruptible Credit 16 hour control (Customers)	0	0	0	0	0	0	0	0	
83	Proposed Energy-Related Charges									
84	Revenues at Current rates	$12,971,097	$208,919	$1,146,695	$288,587	$3,895,574	$0	$590,748	$14,932	$19,116,552
85	Remaining Energy-related revenue target	$14,626,769	$234,449	$1,262,424	$322,823	$4,299,164	$122,987	$660,494	$16,479	$21,545,590
86	% increase in Energy-Related Rates	12.76%	12.22%	10.09%	11.86%	10.36%	N/A	11.81%	10.36%	
		$0	$0	$0	$0	$0	$0	$0	$0	
87	Proposed Energy-Related Charges kWh									
88	Proposed Distribution Quantity $/kWh	$0.05251			$0.00218	$0.04880	$0.03753	$0.04302	$0.05018	
89	Proposed Distribution Quantity On Peak $/kWh		$0.11233	$0.00548						
90	Proposed Distribution Quantity Off Peak $/kWh		$0.00154	$0.00164						
91	Proposed Distribution Farm $/kWh	$0.04957								
92	Proposed Distribution Quantity 6 hour control $/kWh	$0.04618								
93	Proposed Distribution Quantity 16 hour control $/kWh	$0.04534								
94	Base Rates Revenue Proof									
95	Proposed Customer Charge Revenues									
96	Total Customer Charge Revenues	$6,228,588	$77,419	$666,328	$728,962	$1,048,501	$0	$169,666	$3,253	$8,922,717
97	Proposed Demand-Related Revenues									
98	Demand Charge	$0	$0	$8,124,339	$4,381,840	$0	$0	$0	$0	$12,506,180

Line		DOMESTIC SERVICE RATE D	DOMESTIC SERVICE Opt Peak Load Pricing RATE D-10	GENERAL SERVICE TIME-OF-USE RATE G-1	GENERAL LONG HOUR SERVICE RATE G-2	GENERAL SERVICE RATE G-3	OUTDOOR LIGHTING SERVICE RATE M	LIMITED TOTAL ELECTRICAL LIVING RATE T	LIMITED COMMERCIAL SPACE HEATING RATE V	Company Total
	(X)	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
99	High Voltage Delivery Credit	$0	$0	-$163,556	-$900	$0	$0	$0	$0	-$164,456
100	Optional Demand Surcharge ($)	$0	$0	$28,885	$6,154	$0	$0	$0	$0	$35,039
101	High Voltage Metering Adjustment ($)	$0	$0	-$86,412	-$642	$0	$0	$0	$0	-$87,053
102	Total Demand-Related Revenues	$0	$0	$7,903,256	$4,386,453	$0	$0	$0	$0	$12,289,710
103	Proposed Energy-Related Revenues									
104	Proposed Distribution Quantity $/kWh	$14,494,875	$0	$0	$322,625	$4,299,051	$122,987	$660,446	$16,479	$19,916,463
105	Proposed Distribution Quantity On Peak $/kWh	$0	$228,882	$913,400	$0	$0	$0	$0	$0	$1,142,283
106	Proposed Distribution Quantity Off Peak $/kWh	$0	$5,531	$348,510	$0	$0	$0	$0	$0	$354,041
107	Proposed Distribution Farm $/kWh	$44,354	$0	$0	$0	$0	$0	$0	$0	$44,354
108	Proposed Distribution Quantity 6 hour control $/kWh	$35,530	$0	$0	$0	$0	$0	$0	$0	$35,530
109	Proposed Distribution Quantity 16 hour control $/kWh	$50,801	$0	$0	$0	$0	$0	$0	$0	$50,801
110	Proposed Interruptible Credit 6 hour control	$0	$0	$0	$0	$0	$0	$0	$0	$0
111	Proposed Interruptible Credit 16 hour control	$0	$0	$0	$0	$0	$0	$0	$0	$0
112	Total Energy-Related Revenues	$14,625,560	$234,413	$1,261,910	$322,625	$4,299,051	$122,987	$660,446	$16,479	$21,543,471
113	Proposed Outdoor Lighting Fixed Revenues						$952,946			$952,946
114										
115	Total Proposed Revenues	$20,854,148	$311,833	$9,831,495	$5,438,040	$5,347,552	$1,075,932	$830,112	$19,732	$43,708,844
116		-$1,209	-$36	-$514	-$198	-$113	$0	-$48	-$1	-$2,118

Liberty Utilities (Granite State Electric) Corp.
Test Year Revenues and BIllnig Determinants

REVENUES AT CURRENT RATES									
Base Revenues at May/June 2019 Rates									
	RATE D	RATE D-10	RATE G-1	RATE G-2	RATE G-3	RATE M	RATE T	RATE V	Total
Customer	$5,922,891	$73,620	$603,077	$659,755	$949,162	$0	$161,338	$2,945	$8,372,787
Distribution Quantity	$0	$0	$0	$288,587	$3,895,574	$0	$590,748	$14,932	$4,789,841
Distribution Quantity Block 1	$4,469,287	$0	$0	$0	$0	$0	$0	$0	$4,469,287
Distribution Quantity Block 2	$8,385,909	$0	$0	$0	$0	$0	$0	$0	$8,385,909
Distribution Quantity OnPeak	$0	$203,963	$830,061	$0	$0	$0	$0	$0	$1,034,023
Distribution Quantity OffPeak	$0	$4,956	$316,634	$0	$0	$0	$0	$0	$321,591
Distribution Farm	$39,335	$0	$0	$0	$0	$0	$0	$0	$39,335
Distribution Quantity 6 hour control	$31,514	$0	$0	$0	$0	$0	$0	$0	$31,514
Distribution Quantity 16 hour control	$45,053	$0	$0	$0	$0	$0	$0	$0	$45,053
Distribution Demand	$0	$0	$7,363,277	$3,973,753	$0	$0	$0	$0	$11,337,030
Distribution Demand: Optional Billing	$0	$0	$28,885	$6,154	$0	$0	$0	$0	$35,039
Distribution: High Voltage Delivery Credit	$0	$0	-$148,178	-$815	$0	$0	$0	$0	-$148,993
Interruptible Credit	$0	$0	$0	$0	$0	$0	$0	$0	$0
High Voltage Metering Adjustment			-$86,412	-$642					-$87,053
Fixtures						$935,600			$935,600
Total	$18,893,988	$282,539	$8,907,345	$4,926,792	$4,844,736	$935,600	$752,086	$17,877	$39,560,962
Customer	$5,922,891	$73,620	$603,077	$659,755	$949,162	$0	$161,338	$2,945	$8,372,787
Demand	$0	$0	$7,157,573	$3,978,450	$0	$0	$0	$0	$11,136,023
Energy	$12,971,097	$208,919	$1,146,695	$288,587	$3,895,574	$0	$590,748	$14,932	$19,116,552
Fixtures	$0	$0	$0	$0	$0	$935,600	$0	$0	$935,600
Misc	$0	$0	$0	$0	$0	$0	$0	$0	$0

Liberty Utilities (Granite State Electric) Corp.
Test Year Revenues and BIllnig Determinants

TEST YEAR BILLING DETERMINANTS

Customer Counts	RATE D	RATE D-10	RATE G-1	RATE G-2	RATE G-3	RATE M	RATE T	RATE V	Total
Equivalent Bills	424,580	5,277	1,658	10,882	68,040	-	11,565	211	522,214
Total	424,580	5,277	1,658	10,882	68,040	-	11,565	211	522,214

kWh

	RATE D	RATE D-10	RATE G-1	RATE G-2	RATE G-3	RATE M	RATE T	RATE V	Total
Distribution Quantity	-	-	-	147,993,116	88,095,304	3,277,030	15,352,073	328,389	255,045,912
Distribution Quantity Block 1	95,969,225	-	-	-	-	-	-	-	95,969,225
Distribution Quantity Block 2	180,071,056	-	-	-	-	-	-	-	180,071,056
Distribution Quantity OnPeak	-	2,037,588	166,678,890	-	-	-	-	-	168,716,478
Distribution Quantity OffPeak	-	3,591,661	212,506,102	-	-	-	-	-	216,097,763
Distribution Farm	894,780	-	-	-	-	-	-	-	894,780
Distribution Quantity 6 hour control	769,373	-	-	-	-	-	-	-	769,373
Distribution Quantity 16 hour control	1,120,448	-	-	-	-	-	-	-	1,120,448
Total kWh	278,824,882	5,629,249	379,184,992	147,993,116	88,095,304	3,277,030	15,352,073	328,389	918,685,035

Interruptible Credit	RATE D	RATE D-10	RATE G-1	RATE G-2	RATE G-3	RATE M	RATE T	RATE V	Total
6 hour (Customers)	0	0	0	0	0	0	0	0	-
16 hour (Customers)	0	0	0	0	0	0	0	0	-

kW

	RATE D	RATE D-10	RATE G-1	RATE G-2	RATE G-3	RATE M	RATE T	RATE V	Total
Billing Demand	-	-	951,328	510,109	-	-	-	-	1,461,437
Distribution Demand Optional Billing ($)			$144,424	$30,771					$175,195
High Voltage Delivery (kW)			354,348	1,949					356,297
High Voltage Metering Adjustment ($)			$8,641,165	$64,155					$8,705,320

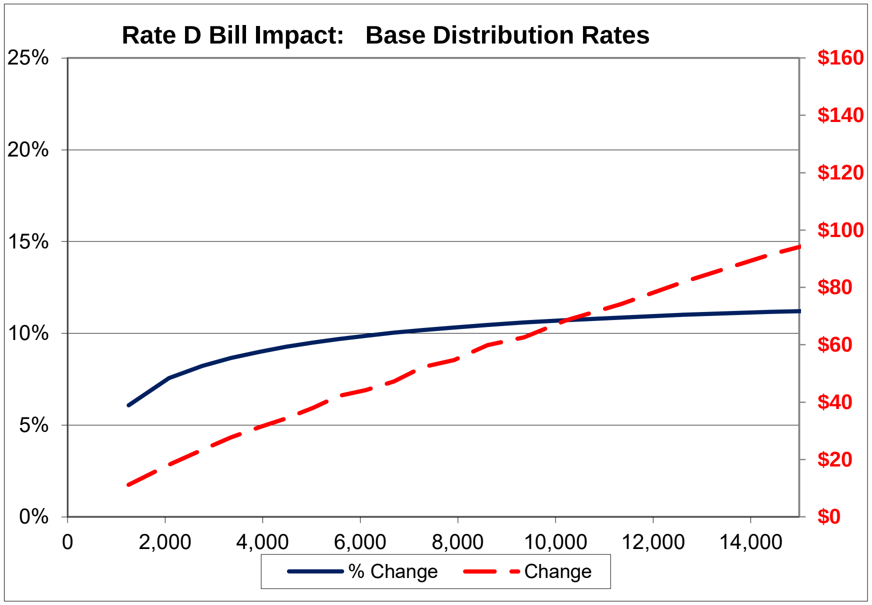
Revenues at July 2019 rates $935,600
Proposed Rate M revenue target $1,075,932
15.00% Proposed Settlement % increase in Rate M

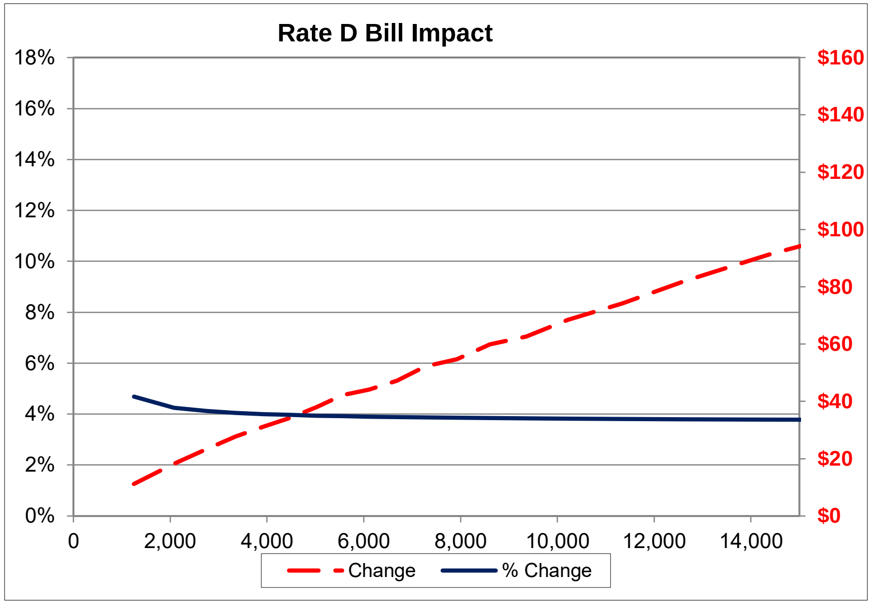
Line	Rate M Fixtures	Test Year 12 months Fixtures	Annual kWh per Fixture	Total Annual kWh	May 2019 Fixed Rates (Annual)	May 2019 Fixed Rates (Monthly)	Proforma Revenues at May 2019 Rates	Proposed Fix Rates (Annual)	Proposed Fixed Rates (Monthly)	Proposed Fixed Rate Revenues	Proposed kWh Rate	Proposed kWh Revenues	Total Revenues at Proposed Rates	Annual Increase per fixture	% Increase
1	Sodium Vapor 4,000	29,246	197	480,117	$87.84	$7.32	$214,079	$95.04	$7.92	$231,536.88	$0.03753	$ 18,018.79	$249,555.67	$14.56	16.57%
2	Sodium Vapor 4,000 Part Night	12	98.50	98	$87.84	$7.32	$88	$98.69	$8.22	$98.69	$0.03753	$ 3.70	$102.39	$14.55	16.57%
3	Sodium Vapor 9,600	21,783	394	715,194	$106.68	$8.89	$193,647	$109.57	$9.13	$198,896.81	$0.03753	$ 26,841.22	$225,738.03	$17.68	16.57%
4	Sodium Vapor 27,500	6,092	984	499,575	$187.56	$15.63	$95,224	$181.71	$15.14	$92,255.32	$0.03753	$ 18,749.05	$111,004.37	$31.08	16.57%
5	Sodium Vapor 50,000	1,430	1,575	187,745	$244.32	$20.36	$29,124	$225.70	$18.81	$26,904.05	$0.03753	$ 7,046.08	$33,950.13	$40.49	16.57%
6	Sodium Vapor 9,600 (Post Top)	4,848	394	159,192	$122.88	$10.24	$49,649	$128.46	$10.70	$51,901.91	$0.03753	$ 5,974.49	$57,876.40	$20.36	16.57%
7	Sodium Vapor 27500 (Flood)	3,083	984	252,770	$189.12	$15.76	$48,581	$183.53	$15.29	$47,145.66	$0.03753	$ 9,486.48	$56,632.14	$31.34	16.57%
8	Sodium Vapor 50,000 (Flood)	5,044	1,575	662,058	$261.12	$21.76	$109,763	$245.28	$20.44	$103,105.76	$0.03753	$ 24,847.03	$127,952.79	$43.27	16.57%
9	Incandescent 1,000	276	406	9,338	$117.48	$9.79	$2,702	$121.71	$10.14	$2,799.37	$0.03753	$ 350.45	$3,149.82	$19.47	16.57%
10	Mercury Vapor 4,000	808	394	26,528	$84.84	$7.07	$5,712	$84.11	$7.01	$5,663.35	$0.03753	$ 995.60	$6,658.95	$14.06	16.57%
11	Mercury Vapor 8,000	1,575	689	90,437	$103.44	$8.62	$13,577	$94.72	$7.89	$12,433.35	$0.03753	$ 3,394.11	$15,827.46	$17.14	16.57%
12	Mercury Vapor 22,000	601	1,575	78,882	$195.60	$16.30	$9,796	$168.90	$14.08	$8,459.39	$0.03753	$ 2,960.44	$11,419.83	$32.41	16.57%
13	Mercury Vapor 63,000	12	3,938	3,938	$371.28	$30.94	$371	$285.01	$23.75	$285.01	$0.03753	$ 147.79	$432.80	$61.53	16.57%
14	Mercury Vapor 22,000 (Flood)	248	1,575	32,488	$216.36	$18.03	$4,463	$193.11	$16.09	$3,983.25	$0.03753	$ 1,219.27	$5,202.52	$35.86	16.57%
15	Mercury Vapor 63,000 (Flood)	0	3,938	-	$373.68	$31.14	$0	$373.68	$31.14	$0.00	$0.03753	$ -	$0.00	$0.00	0.00%
16	Wood Poles	1,391		-	$103.68	$8.64	$12,016	$107.04	$8.92	$14,007.00	$0.00000	$ -	$14,007.00	$17.18	16.57%
17	Fiberglass Direct Embedded	2,940		-	$107.40	$8.95	$26,313	$110.88	$9.24	$30,673.59	$0.00000	$ -	$30,673.59	$17.80	16.57%
18	Fiberglass With Foundation < 25 Ft.	1,742		-	$182.28	$15.19	$26,456	$188.28	$15.69	$30,840.81	$0.00000	$ -	$30,840.81	$30.21	16.57%
19	Fiberglass with Foundation >= 25 ft.	48		-	$304.56	$25.38	$1,218	$314.64	$26.22	$1,420.12	$0.00000	$ -	$1,420.12	$50.47	16.57%
20	Metal Poles Direct Embedded	1,944		-	$217.20	$18.10	$35,186	$224.40	$18.70	$41,017.51	$0.00000	$ -	$41,017.51	$35.99	16.57%
21	Metal Poles with Foundation	1,188		-	$261.96	$21.83	$25,934	$270.60	$22.55	$30,231.83	$0.00000	$ -	$30,231.83	$43.41	16.57%
22	LED 3000 Full-Night Service	173	118	1,701	$129.84	$10.82	$1,872	$61.56	$5.13	$887.49	$0.03753	$ 63.84	$951.33	-$63.85	-49.18%
23	LED 5000 Full-Night Service	779	197	12,788	$135.24	$11.27	$8,779	$64.20	$5.35	$4,167.47	$0.03753	$ 479.93	$4,647.40	-$63.65	-47.06%
24	LED 16000 Full-Night Service	1,363	512	58,148	$156.24	$13.02	$17,744	$99.12	$8.26	$11,257.00	$0.03753	$ 2,182.28	$13,439.28	-$37.90	-24.26%
25	LED 21000 Full-Night Service	43	748	2,680	$205.68	$17.14	$737	$189.36	$15.78	$678.54	$0.03753	$ 100.59	$779.13	$11.75	5.71%
26	LED 5000 Underground Res Full-Night Service	156	118	1,534	$148.56	$12.38	$1,931	$143.40	$11.95	$1,864.21	$0.03753	$ 57.57	$1,921.78	-$0.73	-0.49%
27	LED 9400 Flood Full-Night Service	17	354	499	$149.76	$12.48	$211	$97.56	$8.13	$137.40	$0.03753	$ 18.71	$156.11	-$38.91	-25.98%
28	LED 14600 Flood Full-Night Service	30	512	1,297	$164.04	$13.67	$416	$111.96	$9.33	$283.63	$0.03753	$ 48.68	$332.31	-$32.87	-20.04%
29	LED 4800 Barn Part-Night Service	2	118	22	$57.12	$4.76	$10	$55.32	$4.61	$10.14	$0.03753	$ 0.81	$10.95	$2.60	4.54%
30	Total			3,277,030			$935,600			$952,946		$ 122,987	$1,075,932		

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE

D Current Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$13.95	
First 250 kWh	$0.04657	
Excess 250 kWh	$0.04657	

D Settlement Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$14.67	
First 250 kWh	$0.05251	
Excess 250 kWh	$0.05251	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE

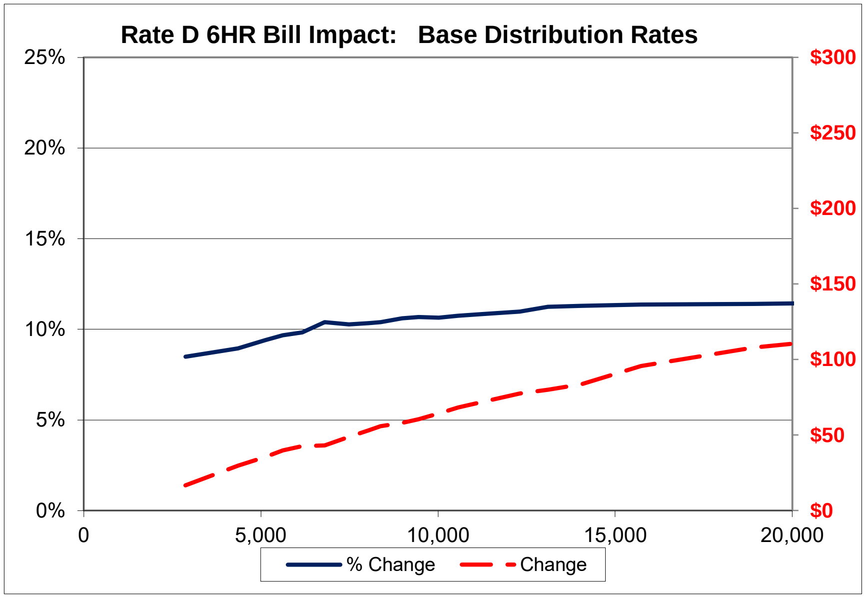
Line	D Current Rates		D Settlement Rates	
1	**D Current Rates**		**D Settlement Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03213	Other Tracking Mechanisms	$0.03213
4				
5	Customer charge	$13.95	Customer charge	$14.67
6				
7				
8	First 250 kWh	$0.04657	First 250 kWh	$0.05251
9	Excess 250 kWh	$0.04657	Excess 250 kWh	$0.05251

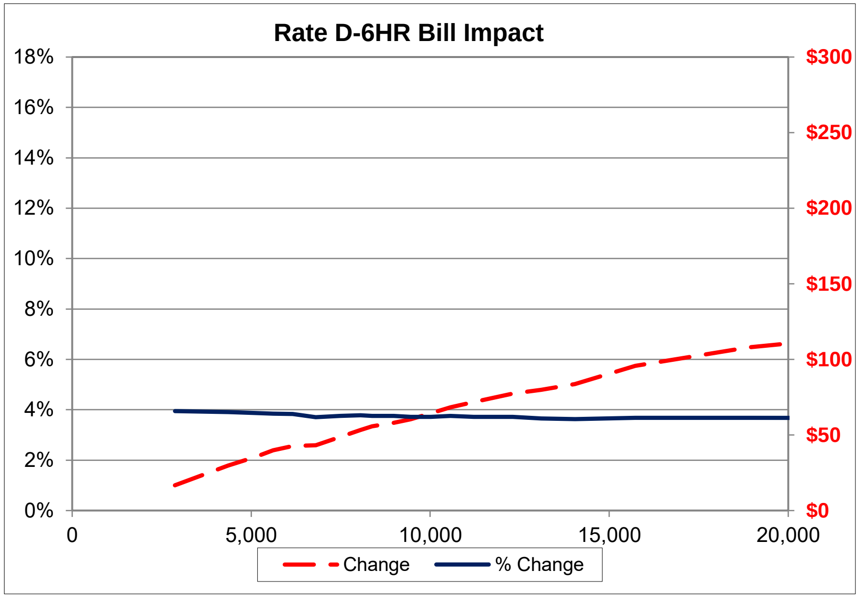
Line	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	1,248	$183.81	$194.97	$11.16	6.1%	$238.42	$249.58	$11.16	4.7%	1,733	1,733	5.0%
11	1,260	2,076	$240.14	$258.29	$18.15	7.6%	$427.48	$445.62	$18.15	4.2%	1,748	3,481	10.0%
12	2,088	2,760	$284.46	$307.83	$23.37	8.2%	$567.32	$590.69	$23.37	4.1%	1,728	5,209	15.0%
13	2,772	3,348	$320.17	$347.90	$27.73	8.7%	$684.77	$712.50	$27.73	4.0%	1,741	6,950	20.0%
14	3,360	3,936	$347.71	$378.98	$31.27	9.0%	$781.50	$812.77	$31.27	4.0%	1,710	8,660	25.0%
15	3,948	4,476	$370.11	$404.39	$34.28	9.3%	$864.24	$898.52	$34.28	4.0%	1,740	10,400	30.0%
16	4,488	5,028	$400.33	$438.32	$38.00	9.5%	$964.67	$1,002.67	$38.00	3.9%	1,726	12,126	35.0%
17	5,040	5,556	$434.87	$477.00	$42.14	9.7%	$1,075.86	$1,118.00	$42.14	3.9%	1,732	13,858	39.9%
18	5,568	6,108	$447.34	$491.49	$44.15	9.9%	$1,132.95	$1,177.10	$44.15	3.9%	1,749	15,607	45.0%
19	6,120	6,684	$470.15	$517.31	$47.17	10.0%	$1,215.59	$1,262.76	$47.17	3.9%	1,754	17,361	50.0%
20	6,696	7,272	$513.42	$565.67	$52.25	10.2%	$1,351.62	$1,403.87	$52.25	3.9%	1,719	19,080	55.0%
21	7,284	7,920	$529.83	$584.50	$54.67	10.3%	$1,419.24	$1,473.91	$54.67	3.9%	1,736	20,816	60.0%
22	7,932	8,604	$573.06	$632.94	$59.89	10.5%	$1,559.78	$1,619.67	$59.89	3.8%	1,731	22,547	65.0%
23	8,616	9,360	$591.21	$653.81	$62.60	10.6%	$1,635.77	$1,698.37	$62.60	3.8%	1,746	24,293	70.0%
24	9,372	10,212	$639.33	$707.81	$68.48	10.7%	$1,794.45	$1,862.93	$68.48	3.8%	1,729	26,022	75.0%
25	10,224	11,340	$683.25	$757.40	$74.15	10.9%	$1,949.14	$2,023.29	$74.15	3.8%	1,740	27,762	80.0%
26	11,352	12,624	$744.37	$826.27	$81.91	11.0%	$2,160.00	$2,241.90	$81.91	3.8%	1,734	29,496	85.0%
27	12,636	14,400	$818.95	$910.36	$91.41	11.2%	$2,418.72	$2,510.13	$91.41	3.8%	1,726	31,222	90.0%
28	14,412	17,580	$930.06	$1,035.69	$105.64	11.4%	$2,806.18	$2,911.82	$105.64	3.8%	1,738	32,960	95.0%
29	17,592	131,676	$1,277.22	$1,427.20	$149.97	11.7%	$4,013.36	$4,163.33	$149.97	3.7%	1,734	34,694	100.0%

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 6 Hour Control

D Current Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$13.95	
Off Peak Use	$0.04096	
First 250 kWh	$0.04657	
Excess 250 kWh	$0.04657	

D Settlement Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$14.67	
Off Peak Use	$0.04618	
First 250 kWh	$0.05251	
Excess 250 kWh	$0.05251	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 6 Hour Control

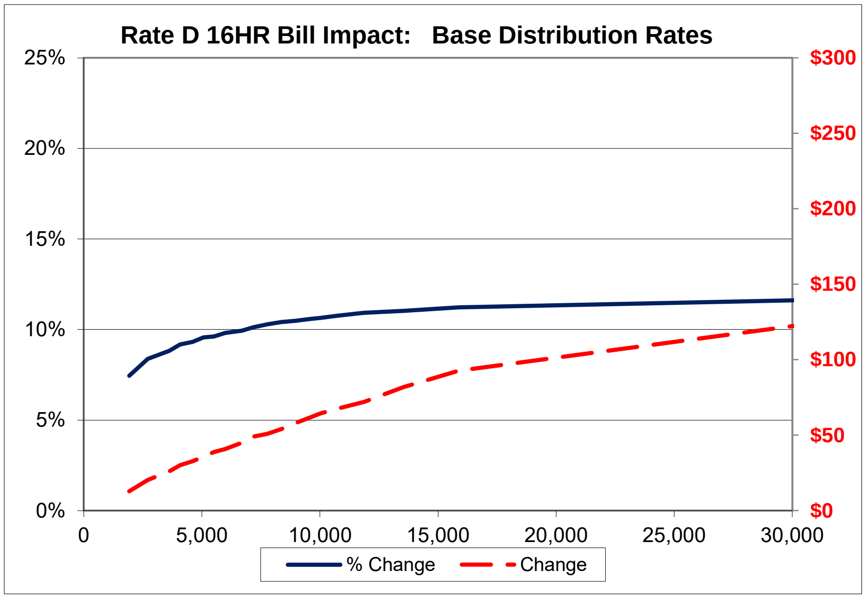
Line	D Current Rates		D Settlement Rates	
1	**D Current Rates**		**D Settlement Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03213	Other Tracking Mechanisms	$0.03213
4				
5	Customer charge	$13.95	Customer charge	$14.67
6				
7	Off Peak Use	$0.04096	Off Peak Use	$0.04618
8	First 250 kWh	$0.04657	First 250 kWh	$0.05251
9	Excess 250 kWh	$0.04657	Excess 250 kWh	$0.05251

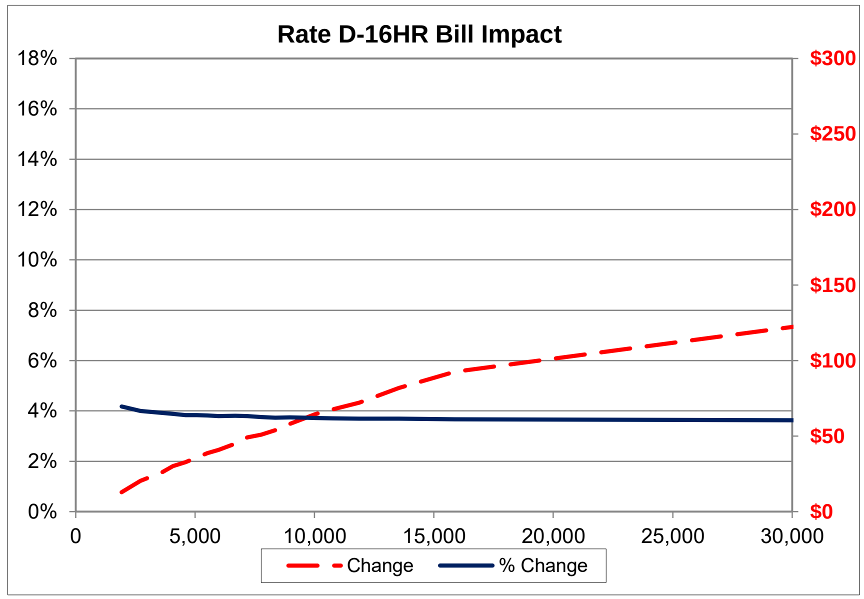
Line	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	2,869	$196.68	$213.38	$16.70	8.5%	$423.74	$440.45	$16.70	3.9%	12	12	4.6%
11	2,869	4,355	$333.67	$363.51	$29.83	8.9%	$762.22	$792.05	$29.83	3.9%	13	25	9.5%
12	4,355	5,131	$377.73	$413.24	$35.51	9.4%	$915.79	$951.29	$35.51	3.9%	13	38	14.5%
13	5,131	5,614	$412.53	$452.43	$39.90	9.7%	$1,038.31	$1,078.20	$39.90	3.8%	13	51	19.5%
14	5,614	6,162	$434.73	$477.48	$42.75	9.8%	$1,115.70	$1,158.44	$42.75	3.8%	13	64	24.4%
15	6,162	6,802	$415.78	$459.02	$43.24	10.4%	$1,166.15	$1,209.39	$43.24	3.7%	13	77	29.4%
16	6,802	7,480	$474.46	$523.16	$48.70	10.3%	$1,298.01	$1,346.70	$48.70	3.8%	14	91	34.7%
17	7,480	8,054	$514.78	$568.01	$53.23	10.3%	$1,406.27	$1,459.50	$53.23	3.8%	13	104	39.7%
18	8,054	8,377	$536.68	$592.49	$55.82	10.4%	$1,486.76	$1,542.58	$55.82	3.8%	13	117	44.7%
19	8,377	8,985	$547.81	$605.88	$58.07	10.6%	$1,548.16	$1,606.23	$58.07	3.8%	13	130	49.6%
20	8,985	9,454	$565.78	$626.21	$60.43	10.7%	$1,627.59	$1,688.02	$60.43	3.7%	13	143	54.6%
21	9,454	10,019	$603.72	$667.99	$64.27	10.6%	$1,727.89	$1,792.16	$64.27	3.7%	13	156	59.5%
22	10,019	10,566	$635.53	$703.87	$68.34	10.8%	$1,821.83	$1,890.17	$68.34	3.8%	13	169	64.5%
23	10,566	11,214	$661.84	$733.54	$71.70	10.8%	$1,925.55	$1,997.24	$71.70	3.7%	14	183	69.8%
24	11,214	12,308	$705.68	$783.13	$77.45	11.0%	$2,080.31	$2,157.76	$77.45	3.7%	13	196	74.8%
25	12,308	13,102	$711.11	$791.04	$79.93	11.2%	$2,182.96	$2,262.89	$79.93	3.7%	13	209	79.8%
26	13,102	14,045	$740.12	$823.75	$83.64	11.3%	$2,301.73	$2,385.36	$83.64	3.6%	13	222	84.7%
27	14,045	15,727	$842.39	$938.10	$95.71	11.4%	$2,596.85	$2,692.55	$95.71	3.7%	13	235	89.7%
28	15,727	18,902	$945.97	$1,053.89	$107.93	11.4%	$2,930.09	$3,038.01	$107.93	3.7%	13	248	94.7%
29	18,902	34,757	$1,226.27	$1,370.86	$144.58	11.8%	$3,950.40	$4,094.98	$144.58	3.7%	14	262	100.0%

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 16 Hour Control

D Current Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$13.95	
Off Peak Use	$0.04021	
First 250 kWh	$0.04657	
Excess 250 kWh	$0.04657	

D Settlement Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$14.67	
Off Peak Use	$0.04534	
First 250 kWh	$0.05251	
Excess 250 kWh	$0.05251	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE - Off Peak Use, 16 Hour Control

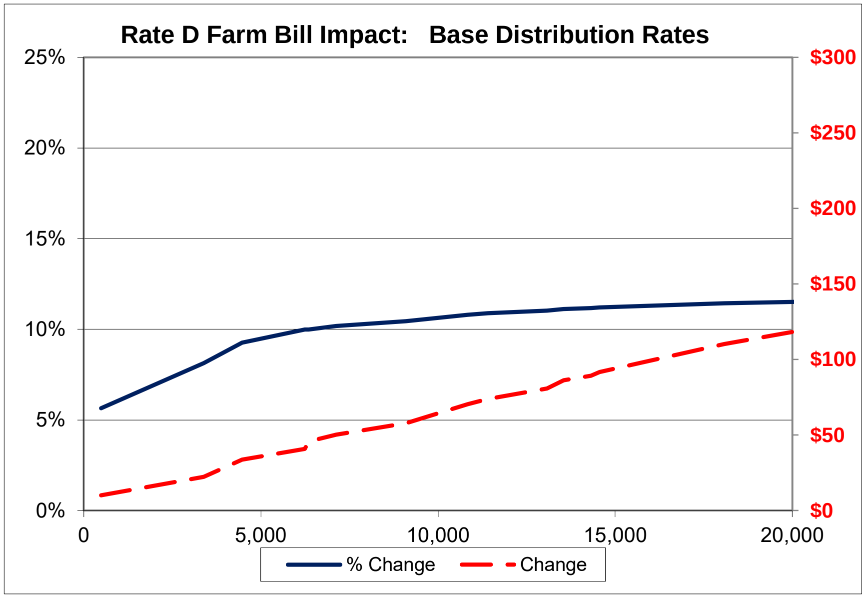
Line	D Current Rates		D Settlement Rates	
1	**D Current Rates**		**D Settlement Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03213	Other Tracking Mechanisms	$0.03213
4				
5	Customer charge	$13.95	Customer charge	$14.67
6				
7	Off Peak Use	$0.04021	Off Peak Use	$0.04534
8	First 250 kWh	$0.04657	First 250 kWh	$0.05251
9	Excess 250 kWh	$0.04657	Excess 250 kWh	$0.05251

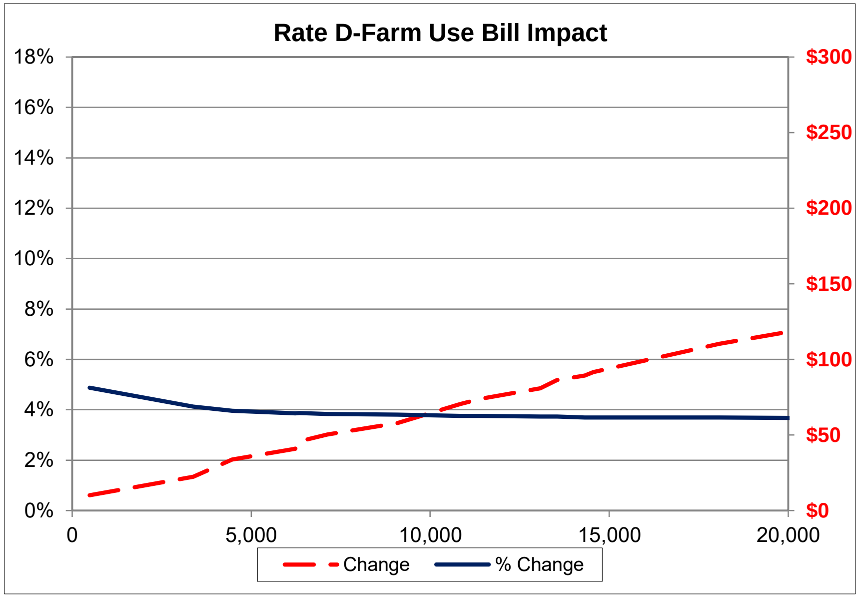
Line	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	1,921	$172.32	$185.17	$12.85	7.5%	$307.27	$320.11	$12.85	4.2%	22	22	4.7%
11	1,921	2,715	$243.65	$264.06	$20.41	8.4%	$511.19	$531.60	$20.41	4.0%	23	45	9.6%
12	2,715	3,614	$295.09	$321.11	$26.02	8.8%	$663.88	$689.91	$26.02	3.9%	24	69	14.7%
13	3,614	4,072	$327.96	$358.09	$30.13	9.2%	$776.53	$806.65	$30.13	3.9%	23	92	19.7%
14	4,072	4,600	$352.08	$384.89	$32.81	9.3%	$856.39	$889.20	$32.81	3.8%	24	116	24.8%
15	4,600	5,067	$373.24	$408.93	$35.69	9.6%	$931.79	$967.49	$35.69	3.8%	23	139	29.7%
16	5,067	5,512	$403.53	$442.33	$38.79	9.6%	$1,015.33	$1,054.12	$38.79	3.8%	24	163	34.8%
17	5,512	5,988	$416.78	$457.68	$40.90	9.8%	$1,077.68	$1,118.58	$40.90	3.8%	23	186	39.7%
18	5,988	6,685	$452.61	$497.54	$44.93	9.9%	$1,179.94	$1,224.88	$44.93	3.8%	24	210	44.9%
19	6,685	7,185	$484.46	$533.56	$49.11	10.1%	$1,293.62	$1,342.73	$49.11	3.8%	23	233	49.8%
20	7,185	7,770	$494.71	$545.64	$50.93	10.3%	$1,355.87	$1,406.80	$50.93	3.8%	23	256	54.7%
21	7,770	8,358	$518.41	$572.40	$54.00	10.4%	$1,445.18	$1,499.18	$54.00	3.7%	24	280	59.8%
22	8,358	8,965	$553.31	$611.33	$58.02	10.5%	$1,551.57	$1,609.58	$58.02	3.7%	23	303	64.7%
23	8,965	9,621	$586.31	$648.36	$62.04	10.6%	$1,662.48	$1,724.52	$62.04	3.7%	24	327	69.9%
24	9,621	10,026	$605.25	$669.70	$64.45	10.6%	$1,734.62	$1,799.07	$64.45	3.7%	23	350	74.8%
25	10,026	10,750	$628.40	$696.08	$67.68	10.8%	$1,823.71	$1,891.39	$67.68	3.7%	24	374	79.9%
26	10,750	11,866	$659.56	$731.64	$72.08	10.9%	$1,954.19	$2,026.27	$72.08	3.7%	23	397	84.8%
27	11,866	13,530	$742.64	$824.54	$81.89	11.0%	$2,214.01	$2,295.90	$81.89	3.7%	24	421	90.0%
28	13,530	15,874	$825.51	$918.17	$92.66	11.2%	$2,522.95	$2,615.61	$92.66	3.7%	23	444	94.9%
29	15,874	30,062	$1,054.57	$1,176.96	$122.39	11.6%	$3,367.96	$3,490.36	$122.39	3.6%	24	468	100.0%

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE - Farm Use

D Current Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$13.95	
Farm Use	$0.04396	
First 250 kWh	$0.04657	
Excess 250 kWh	$0.04657	

D Settlement Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03213
Customer charge	$14.67	
Farm Use	$0.04957	
First 250 kWh	$0.05251	
Excess 250 kWh	$0.05251	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D : DOMESTIC SERVICE - Farm Use

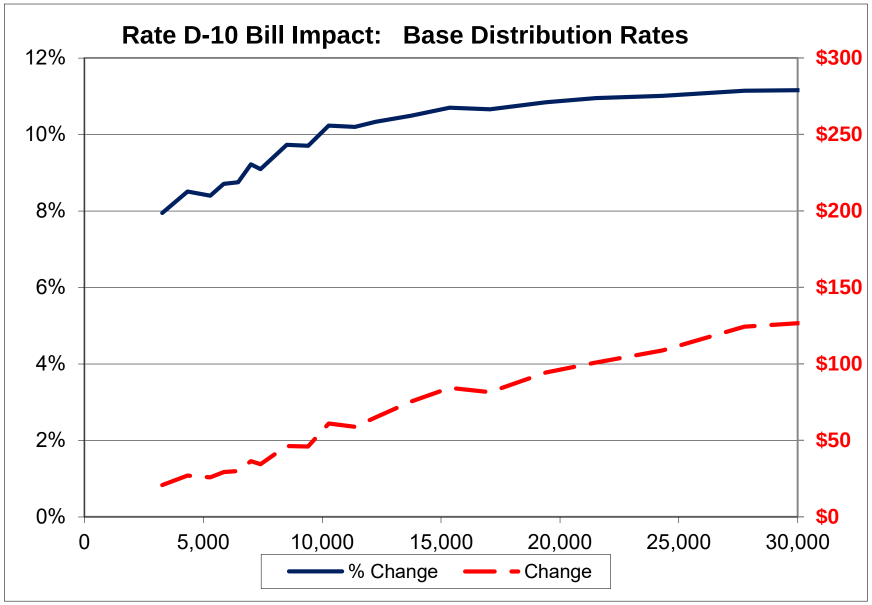
Line	D Current Rates		D Settlement Rates	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03213	Other Tracking Mechanisms	$0.03213
4				
5	Customer charge	$13.95	Customer charge	$14.67
6				
7	Farm Use	$0.04396	Farm Use	$0.04957
8	First 250 kWh	$0.04657	First 250 kWh	$0.05251
9	Excess 250 kWh	$0.04657	Excess 250 kWh	$0.05251

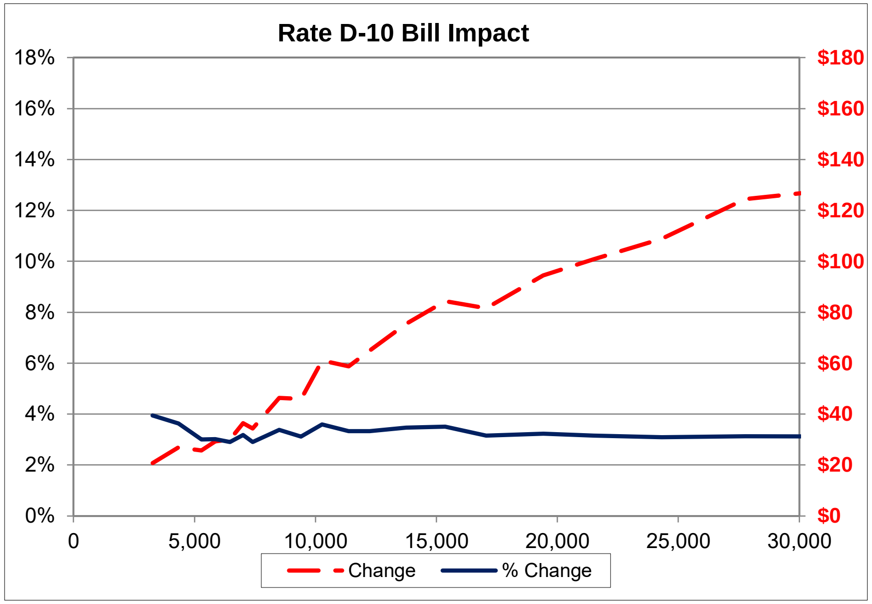
	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	487	$179.02	$189.14	$10.12	5.7%	$207.74	$217.86	$10.12	4.9%	2	2	3.6%
11	487	3,385	$274.70	$297.03	$22.33	8.1%	$541.47	$563.80	$22.33	4.1%	3	5	9.1%
12	3,385	4,472	$364.25	$398.00	$33.75	9.3%	$852.86	$886.61	$33.75	4.0%	3	8	14.5%
13	4,472	6,235	$408.37	$449.17	$40.80	10.0%	$1,056.30	$1,097.11	$40.80	3.9%	3	11	20.0%
14	6,235	6,348	$458.91	$504.74	$45.82	10.0%	$1,183.82	$1,229.65	$45.82	3.9%	2	13	23.6%
15	6,348	7,125	$493.72	$543.99	$50.27	10.2%	$1,310.54	$1,360.81	$50.27	3.8%	3	16	29.1%
16	7,125	9,093	$553.24	$611.08	$57.84	10.5%	$1,518.18	$1,576.02	$57.84	3.8%	3	19	34.5%
17	9,093	10,838	$651.73	$722.15	$70.43	10.8%	$1,873.46	$1,943.88	$70.43	3.8%	3	22	40.0%
18	10,838	11,409	$679.44	$753.40	$73.96	10.9%	$1,969.13	$2,043.09	$73.96	3.8%	2	24	43.6%
19	11,409	13,076	$733.41	$814.26	$80.85	11.0%	$2,163.20	$2,244.05	$80.85	3.7%	3	27	49.1%
20	13,076	13,545	$776.37	$862.69	$86.33	11.1%	$2,313.72	$2,400.05	$86.33	3.7%	3	30	54.5%
21	13,545	14,316	$799.43	$888.71	$89.28	11.2%	$2,413.75	$2,503.03	$89.28	3.7%	3	33	60.0%
22	14,316	14,558	$818.01	$909.67	$91.65	11.2%	$2,483.17	$2,574.82	$91.65	3.7%	2	35	63.6%
23	14,558	18,073	$964.32	$1,074.63	$110.31	11.4%	$2,986.44	$3,096.75	$110.31	3.7%	3	38	69.1%
24	18,073	21,246	$1,066.79	$1,190.18	$123.39	11.6%	$3,369.11	$3,492.51	$123.39	3.7%	3	41	74.5%
25	21,246	26,756	$1,349.48	$1,508.94	$159.46	11.8%	$4,379.01	$4,538.47	$159.46	3.6%	3	44	80.0%
26	26,756	35,641	$1,634.09	$1,829.87	$195.78	12.0%	$5,431.90	$5,627.68	$195.78	3.6%	2	46	83.6%
27	35,641	50,091	$2,164.29	$2,427.74	$263.44	12.2%	$7,325.28	$7,588.72	$263.44	3.6%	3	49	89.1%
28	50,091	132,674	$4,018.58	$4,519.37	$500.78	12.5%	$14,050.75	$14,551.54	$500.78	3.6%	3	52	94.5%
29	132,674	722,508	$16,230.28	$18,288.02	$2,057.74	12.7%	$56,566.76	$58,624.50	$2,057.74	3.6%	3	55	100.0%

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D-10 : DOMESTIC SERVICE Optional Peak Load Pricing

D10 Current Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.02870
Customer charge	$13.95	
Peak kWh	$0.10010	
Off Peak kWh	$0.00138	

D10 Settlement Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.02870
Customer charge	$14.67	
Peak kWh	$0.11233	
Off Peak kWh	$0.00154	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE D-10 : DOMESTIC SERVICE Optional Peak Load Pricing

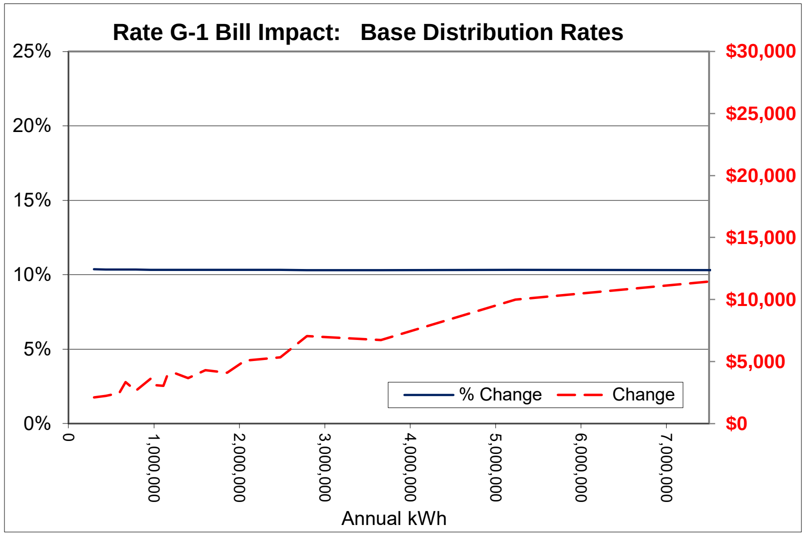
Line	**D10 Current Rates**		**D10 Settlement Rates**	
1	**D10 Current Rates**		**D10 Settlement Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.02870	Other Tracking Mechanisms	$0.02870
4				
5	Customer charge	$13.95	Customer charge	$14.67
6				
7				
8	Peak kWh	$0.10010	Peak kWh	$0.11233
9	Off Peak kWh	$0.00138	Off Peak kWh	$0.00154

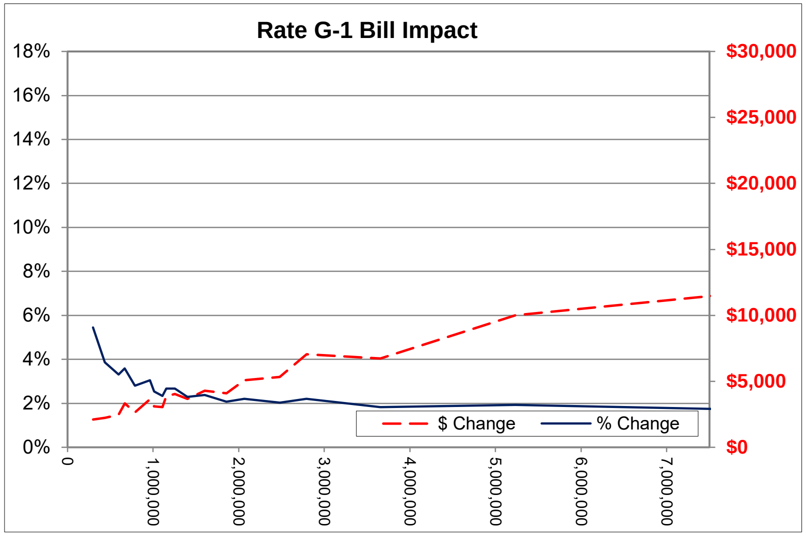
	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking Mechanisms)				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges		
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	Change	% Change	Number of customers	Cumulative customers	% Cumulative customers
10	0	3,272	$261.33	$282.10	$20.77	7.9%	$526.99	$547.76	$20.77	3.9%	20	20	4.6%
11	3,272	4,337	$317.02	$343.98	$26.96	8.5%	$743.01	$769.97	$26.96	3.6%	22	42	9.6%
12	4,337	5,290	$306.71	$332.47	$25.76	8.4%	$856.29	$882.05	$25.76	3.0%	22	64	14.7%
13	5,290	5,859	$336.55	$365.87	$29.32	8.7%	$970.73	$1,000.05	$29.32	3.0%	22	86	19.7%
14	5,859	6,467	$343.14	$373.17	$30.03	8.8%	$1,032.86	$1,062.89	$30.03	2.9%	22	108	24.8%
15	6,467	7,006	$395.48	$431.95	$36.47	9.2%	$1,148.85	$1,185.32	$36.47	3.2%	22	130	29.8%
16	7,006	7,408	$377.59	$411.93	$34.33	9.1%	$1,181.46	$1,215.80	$34.33	2.9%	21	151	34.6%
17	7,408	8,506	$476.39	$522.74	$46.36	9.7%	$1,369.98	$1,416.34	$46.36	3.4%	22	173	39.7%
18	8,506	9,408	$473.39	$519.34	$45.95	9.7%	$1,472.09	$1,518.04	$45.95	3.1%	22	195	44.7%
19	9,408	10,276	$596.50	$657.52	$61.02	10.2%	$1,695.87	$1,756.89	$61.02	3.6%	22	217	49.8%
20	10,276	11,375	$576.61	$635.41	$58.80	10.2%	$1,765.39	$1,824.19	$58.80	3.3%	22	239	54.8%
21	11,375	12,247	$628.62	$693.60	$64.98	10.3%	$1,951.57	$2,016.54	$64.98	3.3%	22	261	59.9%
22	12,247	13,747	$718.63	$794.00	$75.38	10.5%	$2,172.18	$2,247.55	$75.38	3.5%	22	283	64.9%
23	13,747	15,366	$788.22	$872.60	$84.37	10.7%	$2,402.45	$2,486.82	$84.37	3.5%	21	304	69.7%
24	15,366	17,055	$765.12	$846.68	$81.56	10.7%	$2,584.51	$2,666.07	$81.56	3.2%	22	326	74.8%
25	17,055	19,418	$870.86	$965.32	$94.46	10.8%	$2,922.07	$3,016.53	$94.46	3.2%	22	348	79.8%
26	19,418	21,508	$920.93	$1,021.76	$100.83	10.9%	$3,201.77	$3,302.60	$100.83	3.1%	22	370	84.9%
27	21,508	24,317	$988.51	$1,097.36	$108.85	11.0%	$3,522.77	$3,631.62	$108.85	3.1%	22	392	89.9%
28	24,317	27,759	$1,116.02	$1,240.42	$124.40	11.1%	$3,979.68	$4,104.08	$124.40	3.1%	22	414	95.0%
29	27,759	64,654	$1,418.89	$1,580.26	$161.37	11.4%	$5,314.72	$5,476.09	$161.37	3.0%	22	436	100.0%

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE G-1: GENERAL SERVICE TIME-OF-USE

G-1 Current Rates		
Energy Services		$0.06745
Other Tracking Mechanisms		$0.02612
Customer charge	$363.65	
Demand Charge	$7.74	
Peak kWh	$0.00498	
Off Peak kWh	$0.00149	

G-1 Settlement Rates		
Energy Services		$0.06745
Other Tracking Mechanisms		$0.02612
Customer charge	$401.79	
Demand Charge	$8.54	
Peak kWh	$0.00548	
Off Peak kWh	$0.00164	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE G-1: GENERAL SERVICE TIME-OF-USE

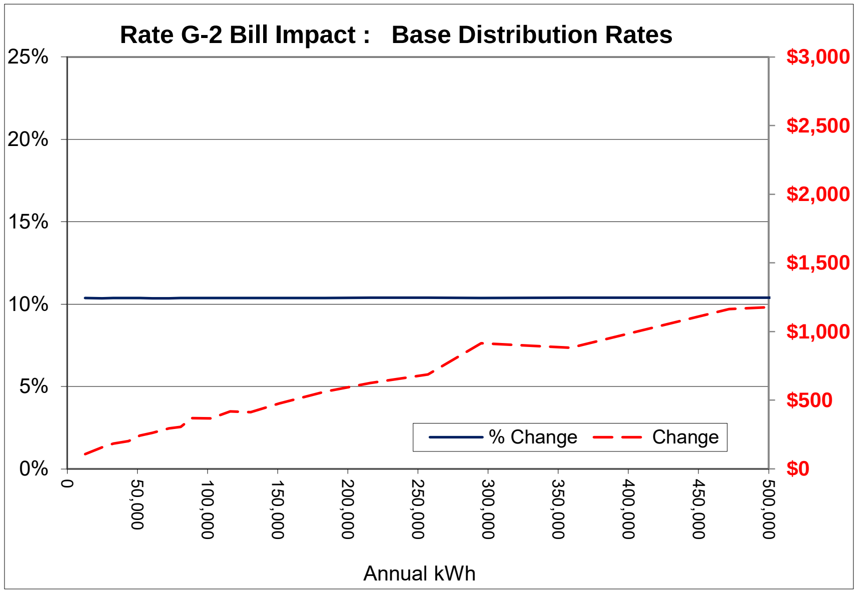
Line	G-1 Current Rates		G-1 Settlement Rates	
2	Energy Services	$0.06745	Energy Services	$0.06745
3	Other Tracking Mechanisms	$0.02612	Other Tracking Mechanisms	$0.02612
4				
5	Customer charge	$363.65	Customer charge	$401.79
6				
7	Demand chrge	$7.74	Demand charge	$8.54
8	Peak kWh	$0.00498	Peak kWh	$0.00548
9	Off Peak kWh	$0.00149	Off Peak kWh	$0.00164

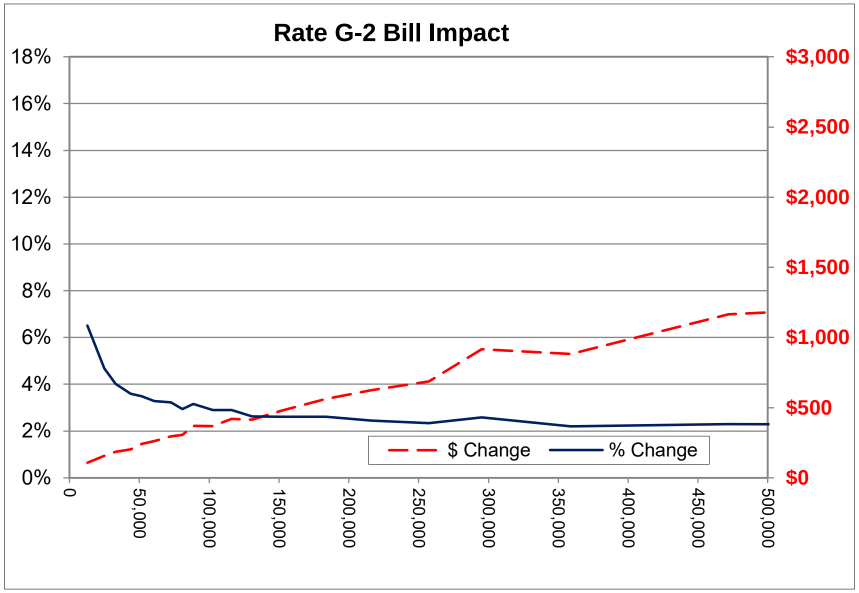
	Annual Use Range (kWh)		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Settlement Rates
10	0	299,386	$20,322	$22,427	$2,105	10.4%	$38,667	$40,772	$2,105	5.4%	6	6	4.4%	175,391	$0.1159	$0.1279
11	299,386	437,986	$21,510	$23,737	$2,227	10.4%	$57,701	$59,928	$2,227	3.9%	7	13	9.6%	366,979	$0.0586	$0.0647
12	437,986	595,428	$23,827	$26,292	$2,464	10.3%	$74,343	$76,808	$2,464	3.3%	7	20	14.8%	517,382	$0.0461	$0.0508
13	595,428	669,238	$32,282	$35,620	$3,338	10.3%	$93,220	$96,558	$3,338	3.6%	7	27	20.0%	640,708	$0.0504	$0.0556
14	669,238	787,986	$25,542	$28,184	$2,643	10.3%	$94,232	$96,875	$2,643	2.8%	6	33	24.4%	714,318	$0.0358	$0.0395
15	787,986	961,987	$35,082	$38,708	$3,626	10.3%	$118,928	$122,554	$3,626	3.0%	7	40	29.6%	871,224	$0.0403	$0.0444
16	961,987	1,011,107	$29,946	$33,041	$3,095	10.3%	$121,623	$124,718	$3,095	2.5%	7	47	34.8%	972,757	$0.0308	$0.0340
17	1,011,107	1,109,539	$29,467	$32,512	$3,045	10.3%	$130,094	$133,139	$3,045	2.3%	7	54	40.0%	1,061,363	$0.0278	$0.0306
18	1,109,539	1,153,487	$37,345	$41,203	$3,858	10.3%	$144,231	$148,089	$3,858	2.7%	6	60	44.4%	1,134,986	$0.0329	$0.0363
19	1,153,487	1,255,188	$39,041	$43,074	$4,032	10.3%	$150,960	$154,992	$4,032	2.7%	7	67	49.6%	1,181,570	$0.0330	$0.0365
20	1,255,188	1,400,986	$35,495	$39,160	$3,665	10.3%	$159,599	$163,263	$3,665	2.3%	7	74	54.8%	1,305,488	$0.0272	$0.0300
21	1,400,986	1,601,988	$41,599	$45,893	$4,295	10.3%	$180,522	$184,817	$4,295	2.4%	7	81	60.0%	1,455,987	$0.0286	$0.0315
22	1,601,988	1,855,786	$39,592	$43,677	$4,086	10.3%	$197,433	$201,519	$4,086	2.1%	6	87	64.4%	1,644,581	$0.0241	$0.0266
23	1,855,786	2,067,586	$49,158	$54,233	$5,074	10.3%	$230,578	$235,652	$5,074	2.2%	7	94	69.6%	1,908,611	$0.0258	$0.0284
24	2,067,586	2,480,391	$51,738	$57,077	$5,339	10.3%	$263,849	$269,189	$5,339	2.0%	7	101	74.8%	2,207,903	$0.0234	$0.0259
25	2,480,391	2,792,386	$68,399	$75,452	$7,053	10.3%	$320,467	$327,519	$7,053	2.2%	7	108	80.0%	2,649,323	$0.0258	$0.0285
26	2,792,386	3,656,788	$65,267	$71,998	$6,731	10.3%	$367,388	$374,120	$6,731	1.8%	6	114	84.4%	3,084,763	$0.0212	$0.0233
27	3,656,788	5,231,786	$96,906	$106,902	$9,997	10.3%	$517,578	$527,575	$9,997	1.9%	7	121	89.6%	4,270,802	$0.0227	$0.0250
28	5,231,786	8,164,189	$115,151	$127,027	$11,876	10.3%	$701,451	$713,328	$11,876	1.7%	7	128	94.8%	5,846,987	$0.0197	$0.0217
29	8,164,189	58,034,730	$424,866	$468,640	$43,774	10.3%	$2,448,437	$2,492,211	$43,774	1.8%	7	135	100.0%	14,501,914	$0.0293	$0.0323

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE G-2: GENERAL LONG HOUR SERVICE

G-2 Current Rates		
Energy Services		$0.06745
Other Tracking Mechanisms		$0.02922
Customer charge	$60.63	
Demand Charge	$7.79	
kWh Charge	$0.00195	

G-2 Settlement Rates		
Energy Services		$0.06745
Other Tracking Mechanisms		$0.02922
Customer charge	$66.99	
Demand Charge	$8.59	
kWh Charge	$0.00218	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE G-2: GENERAL LONG HOUR SERVICE

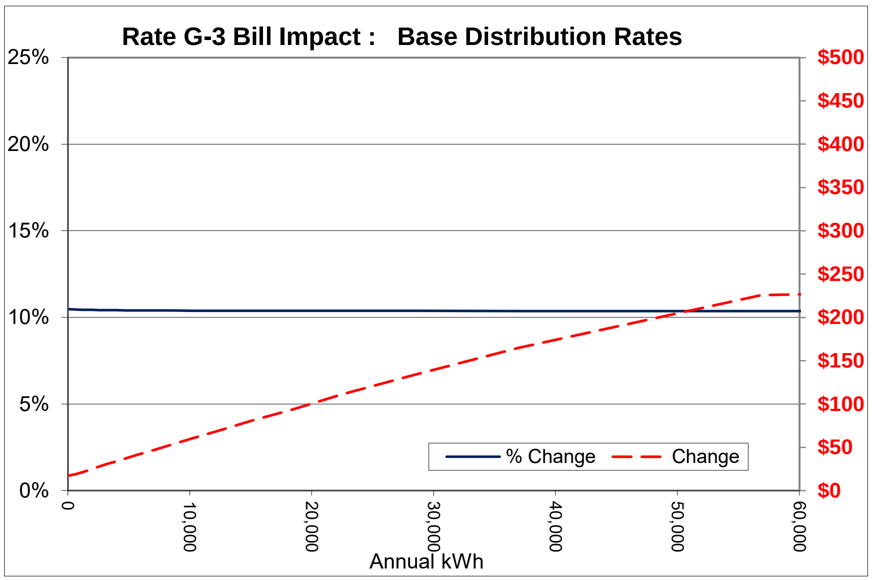
Line				
1	**G-2 Current Rates**		**G-2 Settlement Rates**	
2	Energy Services	$0.06745	Energy Services	$0.06745
3	Other Tracking Mechanisms	$0.02922	Other Tracking Mechanisms	$0.02922
4				
5	Customer charge	$60.63	Customer charge	$66.99
6				
7	Demand charge	$7.79	Demand charge	$8.59
8	kWh Charge	$0.00195	kWh Charge	$0.00218
9				

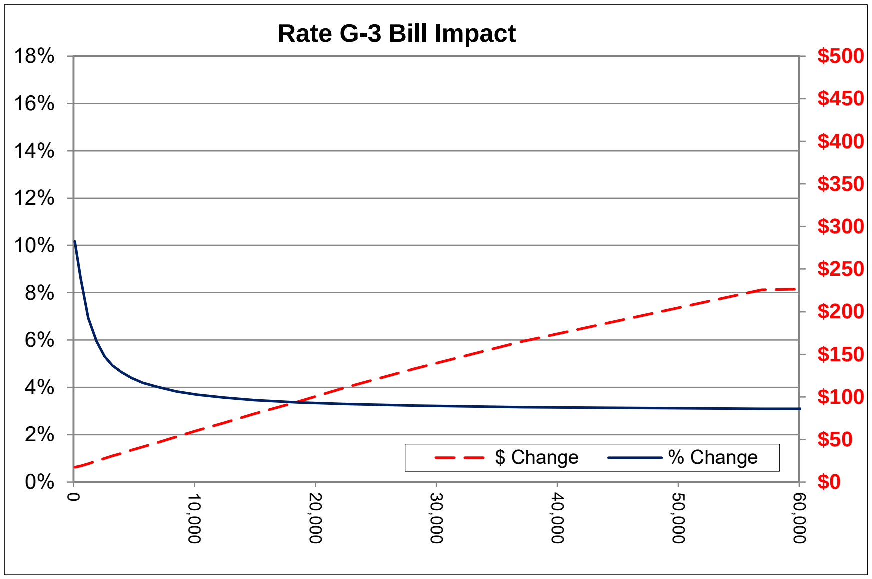
	Annual Use Range		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Settlement Rates
10	0	12,846	$1,039	$1,146	$108	10.4%	$1,653	$1,761	$108	6.5%	39	39	4.5%	5,599	$0.1855	$0.2047
11	12,846	24,865	$1,508	$1,664	$156	10.4%	$3,338	$3,495	$156	4.7%	43	82	9.5%	18,654	$0.0808	$0.0892
12	24,865	32,964	$1,784	$1,969	$185	10.4%	$4,596	$4,781	$185	4.0%	44	126	14.6%	28,908	$0.0617	$0.0681
13	32,964	43,786	$1,957	$2,160	$203	10.4%	$5,652	$5,855	$203	3.6%	43	169	19.6%	37,969	$0.0515	$0.0569
14	43,786	51,821	$2,334	$2,576	$242	10.4%	$6,951	$7,193	$242	3.5%	43	212	24.6%	47,573	$0.0491	$0.0542
15	51,821	60,673	$2,534	$2,796	$262	10.4%	$8,010	$8,273	$262	3.3%	44	256	29.7%	56,448	$0.0449	$0.0495
16	60,673	72,534	$2,846	$3,141	$295	10.4%	$9,152	$9,447	$295	3.2%	43	299	34.6%	64,956	$0.0438	$0.0484
17	72,534	80,887	$2,947	$3,252	$306	10.4%	$10,398	$10,704	$306	2.9%	43	342	39.6%	76,892	$0.0383	$0.0423
18	80,887	88,708	$3,565	$3,935	$370	10.4%	$11,719	$12,089	$370	3.2%	44	386	44.7%	84,167	$0.0424	$0.0468
19	88,708	102,493	$3,546	$3,914	$368	10.4%	$12,695	$13,063	$368	2.9%	43	429	49.7%	94,319	$0.0376	$0.0415
20	102,493	116,102	$4,043	$4,462	$419	10.4%	$14,490	$14,909	$419	2.9%	43	472	54.7%	107,752	$0.0375	$0.0414
21	116,102	130,794	$3,989	$4,403	$414	10.4%	$15,783	$16,197	$414	2.6%	44	516	59.8%	121,668	$0.0328	$0.0362
22	130,794	151,193	$4,593	$5,070	$477	10.4%	$18,249	$18,725	$477	2.6%	43	559	64.8%	140,781	$0.0326	$0.0360
23	151,193	183,655	$5,422	$5,984	$562	10.4%	$21,589	$22,152	$562	2.6%	43	602	69.8%	166,489	$0.0326	$0.0359
24	183,655	216,195	$6,018	$6,644	$625	10.4%	$25,518	$26,143	$625	2.4%	44	646	74.9%	200,973	$0.0299	$0.0331
25	216,195	257,193	$6,618	$7,306	$688	10.4%	$29,369	$30,056	$688	2.3%	43	689	79.8%	234,386	$0.0282	$0.0312
26	257,193	295,033	$8,829	$9,745	$916	10.4%	$35,409	$36,325	$916	2.6%	43	732	84.8%	274,075	$0.0322	$0.0356
27	295,033	358,876	$8,486	$9,368	$882	10.4%	$40,017	$40,899	$882	2.2%	44	776	89.9%	324,711	$0.0261	$0.0289
28	358,876	471,796	$11,216	$12,380	$1,165	10.4%	$50,655	$51,819	$1,165	2.3%	43	819	94.9%	405,352	$0.0277	$0.0305
29	471,796	2,019,793	$18,282	$20,183	$1,902	10.4%	$95,227	$97,129	$1,902	2.0%	44	863	100.0%	760,776	$0.0240	$0.0265

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE G-3: GENERAL SERVICE

G-3 Current Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.02969
Customer charge	$13.95	
kWh Charge	$0.04422	

G-3 Settlement Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.02969
Customer charge	$15.41	
kWh Charge	$0.04880	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE G-3: GENERAL SERVICE

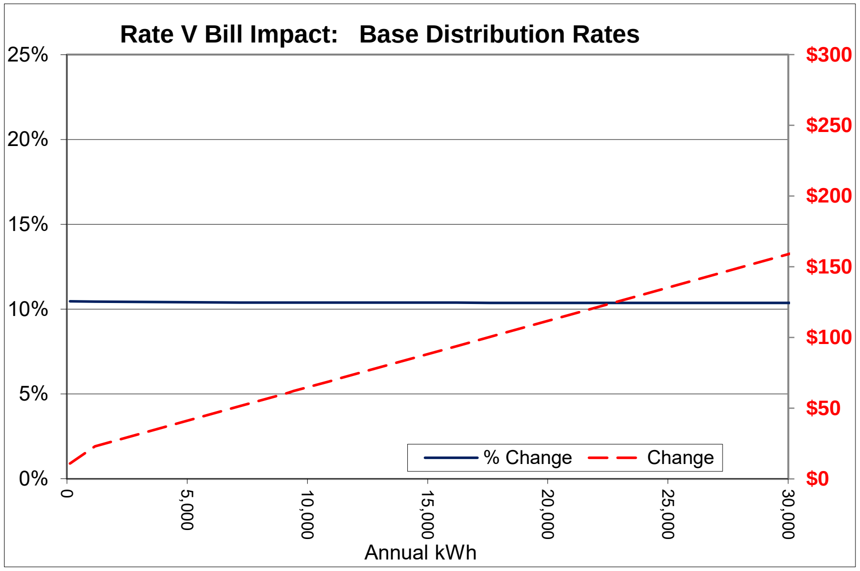
Line	G-3 Current Rates		G-3 Settlement Rates	
1	**G-3 Current Rates**		**G-3 Settlement Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.02969	Other Tracking Mechanisms	$0.02969
4				
5	Customer charge	$13.95	Customer charge	$15.41
6				
7				
8	kWh Charge	$0.04422	kWh Charge	$0.04880
9				

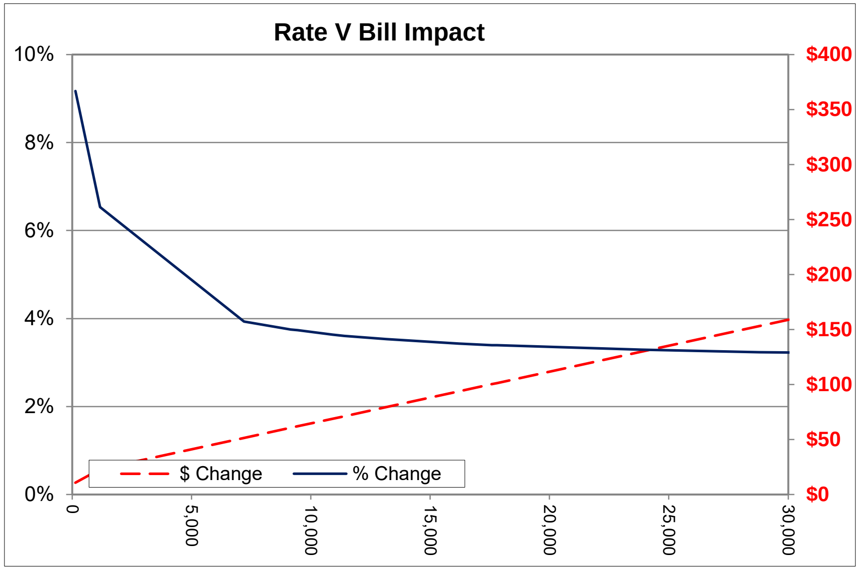
Line	Annual Use		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Settlement Rates
10	0	120	$166	$184	$17	10.5%	$171	$189	$17	10.2%	182	182	3.3%	29	$5.8344	$6.4449
11	120	581	$180	$199	$19	10.5%	$218	$237	$19	8.6%	277	459	8.4%	333	$0.5408	$0.5974
12	581	1,235	$206	$227	$22	10.4%	$310	$331	$22	6.9%	278	737	13.5%	920	$0.2237	$0.2471
13	1,235	1,922	$237	$261	$25	10.4%	$415	$440	$25	6.0%	277	1014	18.6%	1,580	$0.1498	$0.1655
14	1,922	2,570	$266	$293	$28	10.4%	$521	$549	$28	5.3%	277	1291	23.7%	2,263	$0.1175	$0.1297
15	2,570	3,218	$293	$324	$31	10.4%	$619	$650	$31	4.9%	278	1569	28.8%	2,888	$0.1016	$0.1122
16	3,218	3,960	$324	$358	$34	10.4%	$726	$760	$34	4.6%	277	1846	33.9%	3,564	$0.0909	$0.1004
17	3,960	4,813	$359	$397	$37	10.4%	$852	$889	$37	4.4%	277	2123	38.9%	4,367	$0.0822	$0.0908
18	4,813	5,738	$398	$439	$41	10.4%	$988	$1,029	$41	4.2%	278	2401	44.0%	5,230	$0.0760	$0.0839
19	5,738	6,985	$446	$493	$46	10.4%	$1,158	$1,204	$46	4.0%	277	2678	49.1%	6,306	$0.0708	$0.0781
20	6,985	8,531	$511	$564	$53	10.4%	$1,389	$1,442	$53	3.8%	277	2955	54.2%	7,782	$0.0657	$0.0725
21	8,531	10,250	$583	$644	$61	10.4%	$1,640	$1,701	$61	3.7%	278	3233	59.3%	9,374	$0.0622	$0.0687
22	10,250	12,465	$668	$738	$69	10.4%	$1,944	$2,013	$69	3.6%	277	3510	64.4%	11,311	$0.0591	$0.0652
23	12,465	14,987	$773	$853	$80	10.4%	$2,317	$2,397	$80	3.5%	277	3787	69.5%	13,695	$0.0564	$0.0623
24	14,987	18,468	$904	$997	$94	10.4%	$2,782	$2,875	$94	3.4%	278	4065	74.6%	16,655	$0.0543	$0.0599
25	18,468	22,444	$1,069	$1,180	$111	10.4%	$3,367	$3,477	$111	3.3%	277	4342	79.6%	20,374	$0.0525	$0.0579
26	22,444	28,211	$1,282	$1,415	$133	10.4%	$4,123	$4,256	$133	3.2%	277	4619	84.7%	25,194	$0.0509	$0.0562
27	28,211	37,030	$1,590	$1,755	$165	10.4%	$5,215	$5,380	$165	3.2%	278	4897	89.8%	32,135	$0.0495	$0.0546
28	37,030	56,880	$2,176	$2,402	$226	10.4%	$7,296	$7,522	$226	3.1%	277	5174	94.9%	45,366	$0.0480	$0.0529
29	56,880	1,043,800	$4,716	$5,205	$489	10.4%	$16,308	$16,796	$489	3.0%	278	5452	100.0%	99,321	$0.0475	$0.0524

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE V: LIMITED COMMERCIAL SPACE HEATING

V Current Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.02999
Customer charge	$13.95
kWh Charge	$0.04547

V Settlement Rates	
Energy Services	$0.08299
Other Tracking Mechanisms	$0.02999
Customer charge	$15.41
kWh Charge	$0.05018





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE V: LIMITED COMMERCIAL SPACE HEATING

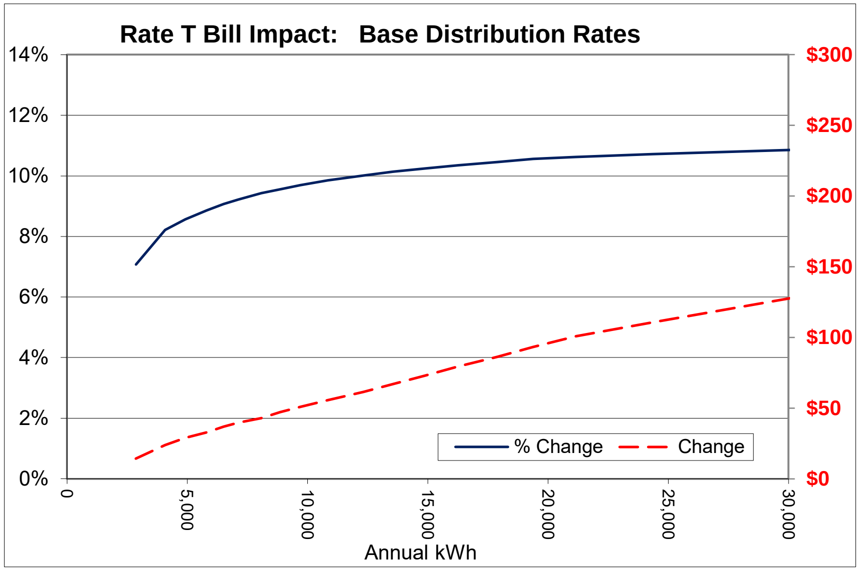
Line	V Current Rates		V Settlement Rates	
1	**V Current Rates**		**V Settlement Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.02999	Other Tracking Mechanisms	$0.02999
4				
5	Customer charge	$13.95	Customer charge	$15.41
6				
7				
8	kWh Charge	$0.04547	kWh Charge	$0.05018
9				

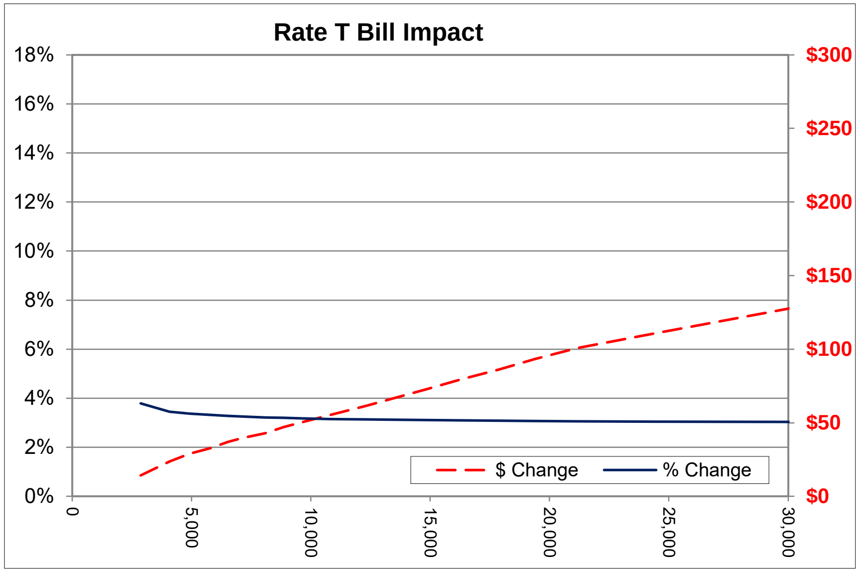
Line	Annual Use Range		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Settlement Rates
10	0	128	$103	$114	$11	10.5%	$117	$128	$11	9.2%	1	1	6.3%	128	$0.8047	$0.8889
11	128	1,165	$220	$243	$23	10.4%	$352	$375	$23	6.5%	1	2	12.5%	1,165	$0.1892	$0.2089
12	1,165	7,187	$494	$546	$51	10.4%	$1,306	$1,358	$51	3.9%	1	3	18.8%	7,187	$0.0688	$0.0759
13	7,187	9,151	$583	$644	$61	10.4%	$1,617	$1,678	$61	3.7%	1	4	25.0%	9,151	$0.0638	$0.0704
14	9,151	9,440	$599	$661	$62	10.4%	$1,665	$1,727	$62	3.7%	1	5	31.3%	9,440	$0.0634	$0.0700
15	9,440	10,911	$664	$732	$69	10.4%	$1,896	$1,965	$69	3.6%	1	6	37.5%	10,911	$0.0608	$0.0671
16	10,911	11,408	$686	$757	$71	10.4%	$1,975	$2,046	$71	3.6%	1	7	43.8%	11,408	$0.0601	$0.0664
17	11,408	13,167	$766	$846	$80	10.4%	$2,254	$2,333	$80	3.5%	1	8	50.0%	13,167	$0.0582	$0.0642
18	13,167	16,199	$904	$998	$94	10.4%	$2,734	$2,828	$94	3.4%	1	9	56.3%	16,199	$0.0558	$0.0616
19	16,199	17,584	$967	$1,067	$100	10.4%	$2,954	$3,054	$100	3.4%	1	10	62.5%	17,584	$0.0550	$0.0607
20	17,584	17,799	$977	$1,078	$101	10.4%	$2,988	$3,089	$101	3.4%	1	11	68.8%	17,799	$0.0549	$0.0606
21	17,799	23,843	$1,252	$1,381	$130	10.4%	$3,945	$4,075	$130	3.3%	1	12	75.0%	23,843	$0.0525	$0.0579
22	23,843	28,803	$1,477	$1,630	$153	10.4%	$4,731	$4,884	$153	3.2%	1	13	81.3%	28,803	$0.0513	$0.0566
23	28,803	49,606	$2,423	$2,674	$251	10.4%	$8,027	$8,279	$251	3.1%	1	14	87.5%	49,606	$0.0488	$0.0539
24	49,606	50,878	$2,481	$2,738	$257	10.4%	$8,229	$8,486	$257	3.1%	1	15	93.8%	50,878	$0.0488	$0.0538
25	50,878	61,120	$2,947	$3,252	$305	10.4%	$9,852	$10,157	$305	3.1%	1	16	100.0%	61,120	$0.0482	$0.0532

COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE T: LIMITED TOTAL ELECTRICAL LIVING

T Current Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03241
Customer charge	$13.95	
kWh Charge	$0.03848	

T Settlement Rates		
Energy Services		$0.08299
Other Tracking Mechanisms		$0.03241
Customer charge	$14.67	
kWh Charge	$0.04302	





COMPARATIVE ANNUAL BILLS UNDER CURRENT AND SETTLEMENT RATES
RATE T: LIMITED TOTAL ELECTRICAL LIVING

Line	T Current Rates		T Settlement Rates	
1	**T Current Rates**		**T Settlement Rates**	
2	Energy Services	$0.08299	Energy Services	$0.08299
3	Other Tracking Mechanisms	$0.03241	Other Tracking Mechanisms	$0.03241
4				
5	Customer charge	$13.95	Customer charge	$14.67
6				
7				
8	kWh Charge	$0.03848	kWh Charge	$0.04302
9				

Line	Annual Use Range		Average Annual Bills (Excluding Tracking				Annual Bills (Including Tracking Mechanisms)				Customers in Ranges				Average $ per kWh	
	Low	High	Current Rates	Settlement Rates	Change	% Change	Current Rates	Settlement Rates	$ Change	% Change	Number of customers	Cumulative customers	% Cumulative customers	Average Annual kWh	Current Rates	Settlement Rates
10	0	2,864	$202	$216	$14	7.1%	$376	$390	$14	3.8%	40	40	4.9%	1,368	$0.1473	$0.1577
11	2,864	4,075	$290	$313	$24	8.2%	$689	$713	$24	3.5%	41	81	9.9%	3,436	$0.0843	$0.0912
12	4,075	4,915	$338	$367	$29	8.6%	$858	$887	$29	3.4%	41	122	15.0%	4,487	$0.0754	$0.0818
13	4,915	5,809	$371	$404	$33	8.9%	$990	$1,023	$33	3.3%	41	163	20.0%	5,347	$0.0694	$0.0755
14	5,809	6,514	$407	$444	$37	9.1%	$1,127	$1,164	$37	3.3%	41	204	25.0%	6,222	$0.0655	$0.0714
15	6,514	7,131	$430	$470	$40	9.2%	$1,217	$1,257	$40	3.3%	40	244	29.9%	6,800	$0.0632	$0.0691
16	7,131	8,084	$455	$497	$43	9.4%	$1,331	$1,373	$43	3.2%	41	285	34.9%	7,557	$0.0602	$0.0658
17	8,084	8,863	$494	$541	$47	9.6%	$1,473	$1,520	$47	3.2%	41	326	40.0%	8,467	$0.0583	$0.0639
18	8,863	9,703	$523	$574	$51	9.7%	$1,596	$1,646	$51	3.2%	41	367	45.0%	9,269	$0.0565	$0.0619
19	9,703	10,845	$563	$619	$56	9.9%	$1,758	$1,813	$56	3.2%	41	408	50.0%	10,325	$0.0546	$0.0599
20	10,845	12,325	$614	$676	$62	10.0%	$1,961	$2,022	$62	3.1%	40	448	54.9%	11,611	$0.0529	$0.0582
21	12,325	13,542	$660	$727	$67	10.1%	$2,146	$2,213	$67	3.1%	41	489	59.9%	12,829	$0.0515	$0.0567
22	13,542	14,873	$713	$786	$73	10.2%	$2,348	$2,421	$73	3.1%	41	530	65.0%	14,139	$0.0504	$0.0556
23	14,873	16,262	$767	$847	$79	10.4%	$2,567	$2,646	$79	3.1%	41	571	70.0%	15,559	$0.0493	$0.0544
24	16,262	17,876	$825	$911	$86	10.5%	$2,796	$2,882	$86	3.1%	41	612	75.0%	17,044	$0.0484	$0.0534
25	17,876	19,379	$884	$977	$93	10.6%	$3,038	$3,132	$93	3.1%	40	652	79.9%	18,634	$0.0474	$0.0524
26	19,379	21,158	$949	$1,050	$101	10.6%	$3,293	$3,394	$101	3.1%	41	693	84.9%	20,267	$0.0468	$0.0518
27	21,158	24,370	$1,032	$1,143	$111	10.7%	$3,625	$3,735	$111	3.1%	41	734	90.0%	22,390	$0.0461	$0.0510
28	24,370	30,990	$1,200	$1,331	$131	10.9%	$4,299	$4,429	$131	3.0%	41	775	95.0%	26,685	$0.0450	$0.0499
29	30,990	669,280	$3,426	$3,819	$393	11.5%	$13,200	$13,593	$393	3.0%	41	816	100.0%	69,131	$0.0496	$0.0552

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Uitilities
Distribution increase due to Rate Case Expense and Recoupment
Effective July 1, 2020 - June 30, 2022
Docket No. DE 19-064

1	Rate Case Expense Through April 22, 2020	$553,642
2		
3	Actual Billed Revenues July 2019 - February 2020	$28,169,453
4	Estimated Billed Revenues March 2020 - June 2020	$12,541,904
5		$40,711,357
6		
7	Calculated July 2019 - June 2020 Revenue @ DE 19-064 Settlement Agreement Rates	$42,547,348
8		
9	Recoupment (Line 7 - Line 5)	$1,835,991
10		
11	Annual Amount Of Rate Case Expense And Recoupment To Recover ((Line 1 + Line 9) / 2)	$1,194,816
12		
13	Settlement Agreement Annual Revenue In DE 19-064	$43,710,962
14	Annual Distribution Rate Increase July 1, 2020 - June 30, 2022 (Line 11 / Line 13)	2.7%

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Permanent Rate Design Including Recoupment, Rate Case Expense Recovery, and REP
Rates Effective July 1, 2020

Rate Class	Distribution Rate Component	Settlement Agreement Permanent July 1, 2020 Rates (a)	Recoupment & Rate Case Exp. Recovery % Increase/ % (Decrease) (b)	DE 19-064 July 1, 2020 Base Distribution Charges (c)	REP Filing DE 20-036 % Increase/ % (Decrease) (d)	July 1, 2020 Base Distribution Charges (e)
D [1]	Customer Charge	$14.67	0.00%	$14.67	0.47%	$14.74
	All kWh	$0.05251	3.89%	$0.05455	0.47%	$0.05480
	16 Hour Off Peak kWh	$0.04534	3.89%	$0.04710	0.47%	$0.04732
	Farm kWh	$0.04957	3.89%	$0.05149	0.47%	$0.05173
	D-6 kWh	$0.04618	3.89%	$0.04797	0.47%	$0.04819
D-11 [2]	Customer Charge	$14.67	0.00%	$14.67	0.47%	$14.74
	Off Peak	$0.03336		$0.03466		$0.03482
	Mid Peak	$0.04910		$0.05100		$0.05124
	Critical Peak	$0.08897		$0.09243		$0.09285
EV [2]	Customer Charge	$11.35	0.00%	$11.35	0.00%	$11.35
	Off Peak	$0.03336		$0.03466		$0.03482
	Mid Peak	$0.04910		$0.05100		$0.05124
	Critical Peak	$0.08897		$0.09243		$0.09285
D-10 [1]	Customer Charge	$14.67	0.00%	$14.67	0.47%	$14.74
	On Peak kWh	$0.11233	3.63%	$0.11640	0.47%	$0.11694
	Off Peak kWh	$0.00154	3.63%	$0.00159	0.47%	$0.00159
G-1	Customer Charge	$401.79	2.73%	$412.76	0.47%	$414.69
	Demand Charge	$8.54	2.73%	$8.77	0.47%	$8.81
	On Peak kWh	$0.00548	2.73%	$0.00562	0.47%	$0.00564
	Off Peak kWh	$0.00164	2.73%	$0.00168	0.47%	$0.00168
	Credit for High Voltage Delivery > 2.4 kv	($0.46)	2.73%	($0.47)	0.47%	($0.47)
G-2	Customer Charge	$66.99	2.73%	$68.81	0.47%	$69.13
	Demand Charge	$8.59	2.73%	$8.82	0.47%	$8.86
	All kWh	$0.00218	2.73%	$0.00223	0.47%	$0.00224
	Credit for High Voltage Delivery > 2.4 kv	($0.46)	2.73%	($0.47)	0.47%	($0.47)
G-3	Customer Charge	$15.41	2.73%	$15.83	0.47%	$15.90
	All kWh	$0.04880	2.73%	$0.05013	0.47%	$0.05036
M	Luminaire Charge					
	HPS 4,000	$7.92	2.73%	$8.13	0.47%	$8.16
	HPS 9,600	$9.13	2.73%	$9.38	0.47%	$9.42
	HPS 27,500	$15.14	2.73%	$15.55	0.47%	$15.62
	HPS 50,000	$18.81	2.73%	$19.32	0.47%	$19.41
	HPS 9,600 (Post Top)	$10.70	2.73%	$10.99	0.47%	$11.04
	HPS 27,500 Flood	$15.29	2.73%	$15.71	0.47%	$15.78
	HPS 50,000 Flood	$20.44	2.73%	$20.99	0.47%	$21.08

Rate Class	Distribution Rate Component	Settlement Agreement Permanent July 1, 2020 Rates (a)	Recoupment & Rate Case Exp. Recovery % Increase/ % (Decrease) (b)	DE 19-064 July 1, 2020 Base Distribution Charges (c)	REP Filing DE 20-036 % Increase/ % (Decrease) (d)	July 1, 2020 Base Distribution Charges (e)
	Incandescent 1,000	$10.14	2.73%	$10.41	0.47%	$10.45
	Mercury Vapor 4,000	$7.01	2.73%	$7.20	0.47%	$7.23
	Mercury Vapor 8,000	$7.89	2.73%	$8.10	0.47%	$8.13
	Mercury Vapor 22,000	$14.08	2.73%	$14.45	0.47%	$14.51
	Mercury Vapor 63,000	$23.75	2.73%	$24.39	0.47%	$24.50
	Mercury Vapor 22,000 Flood	$16.09	2.73%	$16.53	0.47%	$16.60
	Mercury Vapor 63,000 Flood	$31.14	2.73%	$31.99	0.47%	$32.13
LED-1	Luminaire Charge					
	30 Watt Pole Top	$5.13	2.73%	$5.27	0.47%	$5.29
	50 Watt Pole Top	$5.35	2.73%	$5.49	0.47%	$5.51
	130 Watt Pole Top	$8.26	2.73%	$8.48	0.47%	$8.51
	190 Watt Pole Top	$15.78	2.73%	$16.21	0.47%	$16.28
	30 Watt URD	$11.95	2.73%	$12.27	0.47%	$12.32
	90 Watt Flood	$8.13	2.73%	$8.35	0.47%	$8.38
	130 Watt Flood	$9.33	2.73%	$9.58	0.47%	$9.62
	30 Watt Caretaker	$4.61	2.73%	$4.73	0.47%	$4.75
	Rate M, LED-1 & LED-2					
	Pole & Accessory Charge					
	Pole -Wood	$8.92	2.73%	$9.16	0.47%	$9.20
	Fiberglass - Direct Embedded	$9.24	2.73%	$9.49	0.47%	$9.53
	Fiberglass w/Foundation <25 ft	$15.69	2.73%	$16.11	0.47%	$16.18
	Fiberglass w/Foundation >=25 ft	$26.22	2.73%	$26.93	0.47%	$27.05
	Metal Poles - Direct Embedded	$18.70	2.73%	$19.21	0.47%	$19.29
	Metal Poles with Foundation	$22.55	2.73%	$23.16	0.47%	$23.26
	Rate M, LED-1					
	All kWh	$0.03753	2.73%	$0.03855	0.47%	$0.03873
	Rate LED-2					
	All kWh	$0.03753	2.73%	$0.03855	0.47%	$0.03873
T [1]	Customer Charge	$14.67	0.00%	$14.67	0.47%	$14.74
	All kWh	$0.04302	3.43%	$0.04449	0.47%	$0.04469
V	Minimum Charge	$15.41	2.73%	$15.83	0.47%	$15.90
	All kWh	$0.05018	2.73%	$0.05155	0.47%	$0.05179

[1] The Parties agree that, based on the record of this case, a residential customer charge of $14.67 per month is reasonable and the residential kWh rates were developed using the $14.67 customer charge. The parties further recognize that due to the intervening base rate increase for REP investments approved in DE 20-036, the residential customer charge in this settlement needed to be increased to $14.74 (14.67, plus the $.07 increase approved in DE 20-036 for REP).

[2] Rates D-11 and EV are calculated through the TOU model approved in Docket DE 17-189.

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Bill Calculation

Usage 650 kWh

		May 1, 2020 Rates	July 1, 2020 Rates	May 1, 2020 Bill	July 1, 2020 Bill
1	Customer Charge	$14.74	$14.74	$14.74	$14.74
2	Distribution Charge				
3	All kWh - Base Rate	$0.04898	$0.05455	$31.84	$35.46
4	All kWh - REP	$0.00024	$0.00025	$0.16	$0.16
5	All kWh - VMP	$0.00008	$0.00008	$0.05	$0.05
6	Storm Recovery Adjustment	$0.00000	$0.00000	$0.00	$0.00
7	Transmission Charge	$0.02660	$0.02660	$17.29	$17.29
8	Stranded Cost Charge	($0.00072)	($0.00072)	($0.47)	($0.47)
9	System Benefits Charge	$0.00678	$0.00678	$4.41	$4.41
10	Electricity Consumption Tax	$0.00000	$0.00000	$0.00	$0.00
11	Subtotal Retail Delivery Services			$68.01	$71.64
12					
13	Energy Service Charge	$0.07193	$0.07193	$46.75	$46.75
14					
15			Total Bill	$114.77	$118.39
16					
17	**$ increase in 650 kWh Total Residential Bill**				**$3.63**
18	**% increase in 650 kWh Total Residential Bill**				**3.16%**

Reliability Enhancement Plan (REP) and Vegetation Management Plan (VMP) for Calendar Year 2020 (January 1, 2020 – December 31, 2020)

November 15, 2019

Submitted to:
New Hampshire
Public Utilities Commission Staff

Submitted by:

Liberty Utilities

I. Introduction

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company") hereby submits its proposed Reliability Enhancement Plan ("REP") and Vegetation Management Plan ("VMP") for the calendar year 2020 ("CY2020 Plan"). This CY2020 Plan is submitted consistent with the requirements in Attachment F to the Settlement Agreement in Docket No. DE 13-063 that was approved by the Commission in Order No. 25,638 (March 17, 2014), as amended by the Settlement Agreement in Docket No. DE 16-383 that was approved by the Commission in Order No. 26,005 (April 12, 2017). For convenience, a copy of the REP/VMP Program document from DE 13-063 is included as Appendix 5 and the definitions are included as Appendix 6.

In CY2017, Liberty implemented the first year of the four-year trim cycle as approved by the Commission in Docket No. DE 16-383, with CY2019 being the third year of that initial four-year cycle. Advantages of a four-year cycle include minimizing the amount of spot or interim trimming between cycles, and reducing the time between cycles provides for earlier detection of dead/dying and weakly attached limbs forming since the last cycle. Broken tree limbs, both alive and dead, are a major cause of tree interruptions on the Liberty system. A four-year cycle also allows for quicker identification and treatment of trees that have been damaged in storm events and trees with limbs that have heavier foliage especially at the ends of limbs during a good growth year or several good growth years. Thus, it is anticipated that the number of broken tree limbs will decline annually during the cycle resulting in expected reliability benefits. Although growth of tree limbs into the energized space has not been a major source of tree-related interruptions on the

Liberty system, pruning one growing season sooner than the prior five-year cycle minimizes growth and improves safety in areas of reduced or restricted clearances that are imposed either by property owners or as the result of applying American National Standards Institute (ANSI) A300 pruning standards. ANSI A300, titled "Tree, Shrub, and Other Woody Plant Management-Standard Pruning Practices," is the industry standard for tree care operations. The CY2020 Plan encompasses what will be the fourth year of the initial four-year cycle.

As stated above, the transition from a five-year to a four-year trim cycle allows for quicker identification of damaged and hazard trees. As more trees are identified, total costs increase not only for removal of the trees but also for the related traffic control. Given the limits placed on available annual funding since the start of the initial four-year cycle, the Company has more trees marked for removal than there is funding to remove. Additionally, there are a significant number of trees required for removal to increase the side clearance from six feet to the eight-foot side clearance required by Puc 307.10. A request for additional tree removals is being made in the current rate case. In order to meet an anticipated $850,000 annual cost for tree removals for one full four-year cycle, and given the previously budgeted annual level of approximately $450,000, there is a request currently pending before the Commission in Docket No. DE 19-064 for an additional $400,000 annually for four years to provide funding to properly clear the right-of-ways.

As provided in the Appendices, the Commission will see that the cost of performing the work has increased. The workforce for tree work and similar trades is suffering and changing significantly, thus the cost to keep a qualified and competent workforce is increasing. The most recent proposals the Company has received to perform tree work have increased in cost more than anticipated. Liberty was shielded from these realities for the past few years because of a multi-year contract. The Company is currently seeking additional quotes and, after reviewing those responses, intends to award the work on or around December 1, 2019. If the bid rates arrive in line with the most recent quote, the Company, along with others seeking such contracts including other electric utilities, are looking at a significant increase in the cost of having the work performed. Recognizing this cost difference, Liberty is putting forth two Operation and Maintenance ("O&M") budgets in this submittal. Budget Appendix 1A, "Business as Usual," represents the current proposed costs of performing the routine planned and unplanned work and planned work of 223 miles. Budget Appendix 1B, "Alternate," represents an alternate plan of performing reduced miles, 175 miles, and adjusting work back to a five-year plan.

Given that this filing covers the expected scope of the REP and VMP work to be performed during CY2020, the Company is raising the issue of the increased workforce costs to allow for discussion as to: (a) the scope of work for hazard tree removals to be performed during CY2020; (b) the cost of those tree removals; and (c) the preferred methods for recovery of the related costs.

Section 1: Proposed O&M Budget

The proposed O&M budget for VMP activities for 2020 is shown in Appendix 1A – "Business as Usual." As stated above, this budget includes a modification in additional funding for hazard tree removals and an increase in prices to perform the work. For calendar year 2020, Liberty proposes to spend $3,444,000 on O&M expenses related to VMP activities. The VMP O&M spending includes an estimated $838,880 that Liberty will bill to Consolidated Communications for its share of the planned vegetation maintenance work (Appendix 1A, column e, line 14). As shown on line 15, those reimbursements are subtracted from the total amount of VMP O&M expenses to be recovered, resulting in an adjusted total of VMP O&M expenses of $2,605,120. Liberty is submitting this budget for Staff's consideration as it exceeds the O&M budget proposed in the rate case by $660,819.

An alternate budget (as described above) is shown in Appendix 1B "Alternate." For calendar year 2020, Liberty proposes to spend $2,840,690 on O&M expenses related to VMP activities and going back to a five-year cycle. The VMP O&M spending includes $712,791 that Liberty will bill to Consolidated Communications for its share of the planned vegetation maintenance work (Appendix 1B, column e, line 14). As shown on line 15, those reimbursements are subtracted from the total amount of VMP O&M expenses to be recovered, resulting in an adjusted total of VMP O&M expenses of $2,127,899. This exceeds the proposed amount of $1,944,301 in the current rate case by $183,598. This realizes a reduction to $360,000 for tree removals from moving back to a five-year cycle and the $281,690 in workforce increase due to the increased per mile costs. The Company has also requested an additional $400,000 annually over four years to catch up on hazard tree removals. If we are to go back to a five year cycle, that amount would decrease to $320,000 annually for five years.

<u>Vegetation Management Cost Drivers</u>

The primary vegetation management cost drivers for CY2020, in comparison to CY2018 and CY2019, are workforce costs, tree removals, traffic control, and ROW work.

<u>For the proposed "Business as Usual" budget, Appendix 1A:</u>

The first and newest driver is the workforce issues and the increased cost to do the work. The industry and workforce of tree work and beyond is experiencing a shift and loss of workforce. The alternate choices for employment are pulling many of the workforce out of the industry, relocating to higher paying locations, or working for other firms in other trades or sectors that provide more stability, value, and stronger relationships with companies and other parties with which they interact. As a result, the cost of retaining a workforce has been increasing. Liberty has been shielded from this industry trend in recent years because the last bid submittal was reviewed in 2016. In attempts to provide stability, Liberty entered into a multi-year contract in 2017. The three-year contract with an option to extend and negotiate came to fruition in 2019. The quote for the extension came in high and negotiation was not a viable option. The Company is seeking alternate quotes for the fourth and last year of the four-year cycle, CY2020.

The Company has already experienced these changes through the loss of crews over the last year. In 2018, the contractor was able to keep ten crews on property. In 2019, we are often at seven or eight crews, with losses of long time crews occurring. Workforce retention for tree crews and quality work is a frequent topic of discussion and concern at many utilities. It was the central theme at the 2019 Utility Arborist Association Summit meeting held in April 2019.

The Business as Usual budget, Appendix 1A, aligns with our current rate case proposal of performing work on a four-year cycle, including the additional $400,000 of tree removals in the rate case, and keeping all budget line items aligning to $1,944,000 target except the Planned Cycle Trimming, which is an additional $695,000.

The second cost driver is the tree removals, which was also a cost driver last year. Tree removal is necessary to move from the previous six-foot side clearance to the new eight-foot side clearance requirement of Puc 307.10 and to potentially decrease the number of future removals of 5-inch to 12-inch diameter trees in subsequent cycles.

The work prescription for removal, rather than pruning or allowing the trees to remain in the corridor, is governed by Puc 307.10(c) and the ANSI A300 Part 1 standards. Because of the location of these trees related to the clearance area, pruning is not viable and removal is the appropriate work tool. These tree and limb removals align with best practices in the industry, follow professional standards of arboriculture, reliability concerns, and cost effectiveness.

The Company is exposed to higher costs of otherwise private tree removal and "Make Safe" situations. Previously, if the tree work was not within Liberty's scope of work, we would assist a private tree contractor in making the situation safe for them to work. Changes in the language of the ANSI Z133-2017 Safety Requirements for Arboricultural Operations now limit some tree work such that it can only be performed by the utility.

These changes to the ANSI requirements have added the Incidental Line Clearance Contractor status.

Under these new standards, if a property owner engaged a trained and skilled private tree care company to perform tree work within close proximity to the wires, there are situations in which that contractor could not perform the work. To say it another way, a contractor qualified to work for a utility and also works in the residential sector has two different abilities of work pursuant to the ANSI standards. If hired by the utility, they have one chart to abide by. When hired by a residential customer, they have another chart to abide by. There are situations where the tree work can only be performed by a contractor hired by the utility. We have already experienced impacts from this change and anticipate it will increase the costs of tree work.

The increase in the number of trees identified for removal has almost doubled the annual cost of removal through the work planning process. This increased number of trees to be removed will also significantly increase traffic control costs.

The third cost driver in both budgets, similar to last year, is traffic control. The cost of traffic control is directly related to how many tree crews are performing various planned and unplanned maintenance activities and in which municipalities those crews are working. Liberty's Salem district towns of Salem, Pelham, Windham, and Derry continue to require police details and at times require multiple units. Walpole has also recently added additional police traffic control requirements.

The fourth cost driver is the cost of Right of Way clearing. Right of Way continues to be a cost driver in both budgets when comparing to the rate case year of 2018. The CY2018 right-of-way clearing budget was to cover any spot work needed as a result of foot/aerial surveys. Going forward, Liberty is working to adjust the scheduling of the ROW lines to more evenly spread the work over the next four-year cycles.

<u>For the proposed "Alternate" budget, Appendix 1B:</u>

The main driver is, again, related to the workforce as described above.

The Alternate budget, Appendix1B, aligns with our current rate case budget of $1,944,000 with an additional $360,000 for removals. It does not align with our recent four-year cycle, or 223 miles to be trimmed. Rather, it returns us back to a five-year cycle, or 175 miles of planned cycle trimming. Moving back to a five-year cycle would allow us to complete the mileage and removals necessary for reliability and compliance with Puc 307.10, but at a lower cost.

Section 2: Proposed Capital Investment Budget

The capital investment budget for CY2020 is shown in Appendix 2. The capital budget for CY2019 is also shown for comparison under column (b). Liberty has included a capital investment budget of $1,600,000, reflecting planned capital investment closed to plant as part of its CY2020 plan. This amount includes $1,500,000 of planned 2020 capital investment and $100,000 of expected costs for work completed for the Bare Conductor Program in 2019 that will not be recorded until 2020. As a result of timing differences between the project going in service and the closing of the work order,

$100,000 is included in the following year's budget. This is a normal result of the timing involved from when the capital work is performed, completed, invoiced to vendors, and processed through the accounting system. The $1,500,000 of new capital investment for 2020 equals the targeted annual capital spending level approved in Docket No. DE 16-383. Details about the capital projects proposed for CY2020 are set forth in Appendix 3.

In CY2020, four miles of bare mainline primary conductors are targeted for replacement with spacer cable. Spacer cable is installed in areas prone to tree outages that are too costly to rely on vegetation management practices alone to mitigate feeder lockouts. The application of spacer cable, a covered conductor resistant to tree related outages, significantly improves mainline circuit performance during windy and stormy conditions, and affords protection against incidental tree-conductor contact at the end of the trim cycle and contact resulting from branches falling from above the trim zone.

Section 3: Future Reconciliation and Determination of Rate Impacts

Liberty will make its CY2020 reconciliation filing with the Commission by March 15, 2021, to show actual O&M and capital expenses incurred from implementing the REP and VMP for the CY2020. Actual expenses incurred by Liberty in implementing the O&M components of the annual VMP will be reconciled to the proposed O&M amount of $1,944,000. In addition, the revenue requirement associated with capital expenditures incurred as part of the REP investment will be included at the same time as the REP/VMP Adjustment Provision for O&M expense is adjusted. At that time, the rate impacts will be determined using actual spending and any over- or under-collection balance that exists at that time.

II. Conclusion

Liberty requests that a budget be agreed upon that is based on the results of the most recent bid. If the bid numbers come in such that budget Appendix 1B is the only approved option, the Company would then return to a five-year cycle. If the Company is to remain on a four-year cycle, budget Appendix 1A would need to be approved.

Liberty believes that implementation of the REP and VMP programs described in this plan, particularly including funding at the level of the "Ideal" O&M budget, is necessary to ensure that Liberty remains on its current path targeted to maintaining and continually improving reliability performance. These programs have contributed to actual performance improvements seen in recent years, and Liberty is committed to sustaining that improvement.

Appendix 1A - O&M Expenses

Line		(a) CY2018 **Budgeted** Expenses	(b) CY2018 **Actual** Expenses	(c) CY2019 **Adjusted Budget** Expense	(d) CY 2020 **Budgeted** Expenses		(e) CY 2020 **Anticipated** Fairpoint Credits	Reference
1	**VMP O&M**							
2	Work Planners for Veg Plan	$ 227,000	$ 203,159	$ 213,200	$ 205,000		$ 40,180	Appendix 6
3	Spot Tree Trimming	$ 30,000.00	$ 34,811.74	$ 36,900	$ 37,000			Appendix 6
4	Trouble and Restoration Maintenance	$ 30,000	$ 32,078	$ 36,900	$ 37,000			Appendix 6
5	Planned Cycle Trimming	$ 1,120,086	$ 1,166,655	$ 980,000	$ 1,675,000	*	$ 328,300	Appendix 6
6	Police Detail Expenses - Cycle Trimming & Other	$ 290,000	$ 402,083	$ 400,000	$ 400,000		$ 78,400	Appendix 6
7	Hazard Tree Removal - DE 19-064	$ 400,000	$ 535,490	$ 400,000	$ 400,000		$ 196,000	Appendix 6
8	(Rate Case Hazard Tree Removals)				$ 400,000	**	$ 196,000	
9	Interim Trimming	$ 30,000	$ 29,679	$ 30,000	$ 30,000			Appendix 6
10	Tree Planting	$ 5,000	$ 4,345	$ 5,000	$ 10,000			Appendix 6
11	Sub-Transmission Right of Way Clearing	$ -	$ -	$ 205,000	$ 250,000			Appendix 6
12	Sub-Transmission Right of Way Sideline	$ 25,000	$ 14,142	$ -	$ -			Appendix 6
13	Total VMP O&M Expenses	$ 2,157,086	$ 2,422,443	$ 2,307,000	$ 3,444,000			
14	Less: Reimbursements from Consolidated	$ 480,000	$ 478,142	$ 508,267	$ 838,880		$ 838,880	
15	VMP O&M Expenses Net of Consolidated Credits	**$ 1,677,086**	**$ 1,944,301**	**$ 1,798,733**	**$ 2,605,120**			

*Cycle price came in 40% higher

**Included in Docket No. DE 19-064

Appendix 1B "Alternate" - O&M Expenses

Line		(a) CY2018 **Budgeted** Expenses	(b) CY2018 **Actual** Expenses	(c) CY2019 **Adjusted Budget** Expense	(d) CY 2020 **Budgeted** Expenses		(e) CY 2020 **Anticipated** Fairpoint Credits	Reference
1	**VMP O&M**							
2	Work Planners for Veg Plan	$ 227,000	$ 203,159	$ 213,200	$ 155,000		$ 30,380	Appendix 6
3	Spot Tree Trimming	$ 30,000.00	$ 34,811.74	$ 36,900	$ 36,900			Appendix 6
4	Trouble and Restoration Maintenance	$ 30,000	$ 32,078	$ 36,900	$ 36,900			Appendix 6
5	Planned Cycle Trimming	$ 1,120,086	$ 1,166,655	$ 980,000	$ 1,261,690	*	$ 247,291	Appendix 6
6	Police Detail Expenses - Cycle Trimming & Other	$ 290,000	$ 402,083	$ 400,000	$ 320,000		$ 62,720	Appendix 6
7	Hazard Tree Removal	$ 400,000	$ 535,490	$ 400,000	$ 360,000		$ 176,400	Appendix 6
8	Hazard Tree Removals - 5 Year Cycle				$ 320,000	**	$ 156,800	
9	Interim Trimming	$ 30,000	$ 29,679	$ 30,000	$ 30,000			Appendix 6
10	Tree Planting	$ 5,000	$ 4,345	$ 5,000	$ 5,000			Appendix 6
11	Sub-Transmission Right of Way Clearing	$ -	$ -	$ 205,000	$ 250,000			Appendix 6
12	Sub-Transmission Right of Way Sideline	$ 25,000	$ 14,142	$ -	$ -			Appendix 6
13	Total VMP O&M Expenses	$ 2,157,086	$ 2,422,443	$ 2,307,000	$ 2,775,490			
14	Less: Reimbursements from Consolidated	$ 480,000	$ 478,142	$ 508,267	$ 673,591		$ 673,591	
15	VMP O&M Expenses Net of Consolidated Credits	**$ 1,677,086**	**$ 1,944,301**	**$ 1,798,733**	**$ 2,101,899**			

*Cycle price came in 40% higher, but cost is at 5 year cycle

**Included in Docket No. DE 19-064

Appendix 2

REP Capital Investments - Summary

Line	Projects	(a) 2020 Goal		(b) CY 2020 Capital Investment Budget	(c) 2020 Goal		(d) CY 2020 Capital Investment Budget	Reference
1	Bare Conductor Replacement	3.79 mi	$	1,450,000	4 mi.	$	1,500,000	Appendix 3, lines 1-2
2	Single Phase Reclosing Installations	None			None	$	-	
3	Single Phase Trip Saver Installations	6 Units	$	50,000	None	$	-	
4	Previous CY Carryover		$	100,000		$	100,000	Appendix 3, line 3
5	Totals		$	1,600,000 (*)		$	1,600,000	Appendix 3, line 4

(*) From CY 2019 Plan submitted to Staff on November 15, 2018

Appendix 3

Reliability Enhancement Program Capital Costs

Line	Activities	Project Description	Funding Project Number	Work Order	Estimated Capital Investment to be Booked in CY 2020
1	13L3 Bridge St Bare Conductor Replacement	Replace approximately 1.2 miles of bare conductors along Bridge St Salem with 477 Spacer Cable.	8830-2040	TBD	$ 500,000
2	14L2 Nashua Rd / Burns Rd / Mammoth Rd Bare Conductor Replacement	Replace approximately 1.3 miles of bare conductors along Nashua Rd Pelham, 0.7 miles along Burns Rd Pelham and 0.8 miles along Mammoth Rd Pelham with 477 Spacer Cable.	8830-2040	TBD	$ 1,000,000
3	Budgeted Capital Investment Carryover from previous calendar year				$ 100,000
4	Totals				$1,600,000

Appendix 2, line 5, column (d)

Appendix 4A - O&M Expenses

CY 2020 Vegetation Management Activities

Line	Activities	CY 2020 Program Plan (*)	Reference
1	Spot Tree Trimming	As needed	See Appendix 6 for definitions
2	Trouble and Restoration Maintenance	As needed	See Appendix 6 for definitions
3	Planned Cycle Trimming	223.78	See Appendix 6 for definitions
4	Cycle Trimming Police Detail Expenses	As needed	See Appendix 6 for definitions
5	Hazard Tree Removal	As needed	See Appendix 6 for definitions
6	Enhanced Hazard Tree Removal	As needed	See Appendix 6 for definitions
7	Interim Trimming	As needed	See Appendix 6 for definitions
8	Tree Planting	As needed	See Appendix 6 for definitions
10	Other Police Detail Expenses	As needed	See Appendix 6 for definitions
11	**Substation**	**Feeder**	**OH Miles - Distribution**
12	Craft Hill #11	11L1	14.66
13	Slayton Hill #39	39L2	30.31
15	Hanover #6	6L2	4.06
16	Enfield #7	7L1	78.41
17	Spicket River #13	13L3	29.65
18	Pelham #14	14L2	35.39
20	Salem Depot #9	9L1	10.40
22	Salem Depot #9	9L2	1.36
23	Salem Depot #9	9L3	15.04
24	Michael Ave #40	40L3	4.5
25		**Total OH Miles - Distribution**	**223.78**
26	**Sub transmission**		**OH Miles - Sub transmission**
32	BARRON AVE. #10/SALEM DEPOT #9	2352	3.15 Miles/ 30.13 Acres
33	BARRON AVE. #10	2393	.89 Miles/ 6.57 Acres
35	HANOVER #6/MT. SUPPORT #16/LEB #1*	1303/1304	3.15 Miles (6.3 Total)
27		**Total OH Miles - Sub transmission**	7.19 mi/36.7 acres

* Portion completed in 2019

Appendix 4B - O&M Expenses

CY 2020 Vegetation Management Activities

Line	Activities	CY 2020 Program Plan (*)	Reference
1	Spot Tree Trimming	As needed	See Appendix 6 for definitions
2	Trouble and Restoration Maintenance	As needed	See Appendix 6 for definitions
3	Planned Cycle Trimming	174.76	See Appendix 6 for definitions
4	Cycle Trimming Police Detail Expenses	As needed	See Appendix 6 for definitions
5	Hazard Tree Removal	As needed	See Appendix 6 for definitions
6	Enhanced Hazard Tree Removal	As needed	See Appendix 6 for definitions
7	Interim Trimming	As needed	See Appendix 6 for definitions
8	Tree Planting	As needed	See Appendix 6 for definitions
10	Other Police Detail Expenses	As needed	See Appendix 6 for definitions

Line	Substation	Feeder	OH Miles - Distribution
11	**Substation**	**Feeder**	**OH Miles - Distribution**
12			
13			
15			
16	Enfield #7	7L1	78.41
17	Spicket River #13	13L3	29.65
18	Pelham #14	14L2	35.39
20	Salem Depot #9	9L1	10.40
22	Salem Depot #9	9L2	1.36
23	Salem Depot #9	9L3	15.04
24	Michael Ave #40	40L3	4.5
25		**Total OH Miles - Distribution**	**174.76**

Line	Sub transmission		OH Miles - Sub transmission
26	**Sub transmission**		**OH Miles - Sub transmission**
32	BARRON AVE. #10/SALEM DEPOT #9	2352	3.15 Miles/ 30.13 Acres
33	BARRON AVE. #10	2393	.89 Miles/ 6.57 Acres
35	HANOVER #6/MT. SUPPORT #16/LEB #1*	1303/1304	3.15 Miles (6.3 Total)
27		**Total OH Miles - Sub transmission**	7.19 mi/36.7 acres

* Portion completed in 2019

Appendix 5

Granite State Electric Company

Reliability Enhancement Program and Vegetation Management Program

Docket No. DE 13-063

I. REP and VMP Commitment

Beginning April 1, 2014 and until the conclusion of the Company's next distribution rate case, the Company will continue its Reliability Enhancement Program ("REP") and a Vegetation Management Program ("VMP") (collectively, the "Program"), as set forth below.

II. Definitions of REP and VMP Activities

a. Activities included in the REP are the following:

   i. Spacer Cable Expansion/Bare Conductor Replacement
   ii. Single Phase Recloser Replacement/Expansion
   iii. Trip Saver Applications

b. **Activities and expenses included in the VMP are set forth below**:

   i. Spot Tree Trimming;
   ii. Trouble & Restoration Maintenance;
   iii. Planned Cycle Trimming;
   iv. Cycle Trimming Police Details Expenses;
   v. Hazard Tree Removal;
   vi. Interim Trimming;
   vii. Tree Planting;
   viii. Subtransmission Right of Way Clearing; and
   ix. Other Police Detail Expenses.

III. REP and VMP for FY 2014 and Thereafter

a. Beginning with November 15, 2014, the Company will provide its REP and VMP plan (the "Plan") to Staff for the following calendar year for Staff s review. The Company will meet with Staff in technical sessions to discuss the Plan, obtain comments, and answer any questions regarding the plan to be implemented for the subsequent calendar year. After review by Staff, the Company will take all reasonable steps it deems appropriate to carry out and implement the Plan, taking into account the comments of Staff. Review by Staff of the Plan does not relieve the Company of its obligation to operate its business and maintain safe, reliable service through expenditures and other capital investments in the ordinary course of business that are not set forth in the Plan, nor does it bind Staff to a particular position regarding the adequacy and/or effectiveness of the Plan.

Appendix 5

b. The Plan shall provide a description of the activities along with targeted expenditures and investments of the proposed Plan to be implemented during the following calendar year. The Plan will itemize the proposed activities by general category and provide budgets for both operation and maintenance ("O&M") expenses and capital investments expected from implementation of the Plan. The O&M budget will be $1,360,000 (the "Base Plan O&M") for the calendar year ("Base Plan O&M Budget"). The Company may also provide for consideration an alternative Plan with O&M budgets that exceed the O&M Base Amount for the calendar year. The Company will reconcile actual expenditures and investments with the Base Plan O&M amount of $1,360,000 and shall be subject to the REP/VMP Adjustment Provision, as set forth in Section IV below. All of the combined expenses will be counted against the Base Plan O&M amount, along with any REP-related O&M that does not relate to a VMP category.

IV. REP/VMP Adjustment Provision

a. During each calendar year, the Company shall track all O&M expenses incurred in implementing the components of the REP and VMP Plan. By March 15 of each year, the Company will make a reconciliation filing with the Commission. To the extent that the Company, in implementing the Plan, incurs expenses in an amount less than the Base Plan O&M amount, the difference between the Base Plan O&M amount and the amount of expenses actually incurred shall be refunded to customers or credited to customers for future REP/VMP program O&M expenditures, as the Commission determines is appropriate, with interest accruing at the customer deposit rate.

b. To the extent the Plan submitted for review prior to the calendar year includes a budget higher than the Base Plan O&M Budget and the Company incurs expenses over the Base Plan O&M amount (consistent with the alternative budget reviewed by Staff), the incremental expense above the Base Plan O&M amount shall be included in rates, subject to Commission approval, through a uniform adjustment factor on a per kilowatt-hour basis and recovered over a twelve month period, commencing for usage on and after May 1, with interest accruing at the customer deposit rate. Any over or under-recoveries at the end of the twelve month period shall be taken into account in the next REP/VMP Adjustment Provision reconciliation period.

V. REP Capital Investment Allowance

The REP capital investment target shall be $1 million annually. The Company shall track all capital investments made in accordance with the REP for each calendar year. At the same time that the Company makes its reconciliation filing for the REP/VMP Adjustment reconciliation, Granite State shall file a report detailing the actual amount of capital investments made in accordance with implementing the REP during the prior calendar year. The report shall include a calculation of the revenue requirement for adding these additional capital investments into rate

Appendix 5

base, using the Company's current Commission approved capital structure and debt and equity. Provided that the investments were made in accordance with the REP, the Company will be allowed, subject to Commission approval, a permanent increase in its base distribution rates to recover the annual revenue requirement for those investments. This permanent REP Capital Investment Allowance will take effect for usage on and after May 1, at the same time as any REP/VMP Adjustments are implemented for the preceding calendar year as discussed in Section IV above.

VI. Procedure for Adjusting Base Distribution Rates for the REP Capital Investment Allowance

Base distribution rates shall be increased by the ratio of: (i) the incremental revenue requirement associated with the REP capital investment; and (ii) forecasted base distribution revenue for the prospective year.

VII. Annual Report, Plan Deviations, and SAIDI/SAIFI Results

a. At the same time the Company makes its reconciliation and rate adjustment filing (by March 15 of each year), the Company will file an annual report on the prior calendar year's activities. In implementing the Plans, the circumstances encountered during the year may require reasonable deviations from the original Plans reviewed by Staff. In such cases, the Company would include an explanation of any deviations in the report. For cost recovery purposes, the Company has the burden to show that any deviations were due to circumstances out of its reasonable control or, if within its control, were reasonable and prudent. Included in the annual report, the Company will report its SAIDI and SAIFI results for the prior calendar year.

b. The Company shall also report SAIDI/SAIFI results:

   i. Inclusive of all events identified in items ii, iv and v below;
   ii. Using the criteria for major storm exclusions set forth by the Commission and IEEE Standard 1366.
   iii. On a rolling five-year average for each metric in order to minimize the impact of uncontrollable factors;
   iv. Excluding the effect on performance by supply assets owned by others given the potential impact of transmission on the Company's reliability performance;
   v. Excluding planned and notified outages from its calculation of SAIDI and SAIFI, and;
   vi. Consistent with the Puc 300 rules.

c. The Commission's definition of a major storm qualifying for exclusion from SAIDI and SAIFI reporting is 30 concurrent troubles and 15% of customers interrupted, or 45 concurrent troubles. (Troubles are defined as interruption events occurring on either primary or secondary lines).

Appendix 6

Definitions

Augmented Tree-Trimming and Clearing: This program involves the removal of hazard trees and limbs beyond what is normally included in tree trimming to reduce the risk of interruptions on the overhead distribution system. In addition to removing dead, dying, and damaged limbs from above the conductor, we also increase overhead clearances to fifteen feet where practical. This additional work is integrated into routine scheduled trimming program to create a more aggressive approach to removing tree hazards and overhang.

Spot Tree Trimming: (Unplanned Work)
This captures all charges for field follow up, review and execution of corrective action required, if any, to mitigate vegetation management concerns requested or reported by a customer.

Trouble and Restoration Maintenance: (Unplanned Work)
This captures all charges for response and corrective action to mitigate isolated tree related trouble, overhead line requests to mitigate tree related trouble and storm responses not covered by a storm specific charge number.

Planned Cycle Trimming:
This captures all charges for annual fiscal year planned cycle pruning activities but does not include police detail expenses.

Cycle Trimming Police Detail Expenses:
This captures all charges for police detail expenses associated with annual planned cycle trim and tree removals.

Tree Hazard Removal:
This captures all charges for removal of dead, dying and/or structurally weak trees, limbs and leads.

Enhanced Hazard Tree Removal –EHTM: captures all charges for the hazard tree removal program directed at improving reliability of on and off cycle poor performing circuits based on removing dead, dying and/or structurally weak trees, limbs and leads on the three phase portions of those targeted circuits using a Customer Served approach beyond each major reliability device point including the lockout section or station breaker to the first reliability device.

Interim Trimming: (Unplanned work)
This captures all charges for mitigation of tree conditions that threaten reliability of one or more sections of primary conductor on a circuit or circuits not contained in the current fiscal year's annual plan of work.

Tree Planting:
This captures all charges for tree replacements in exchange for tree removals of full clearance, tree replacement to remediate property owner complaints, trees planted for Arbor Day events.

Sub-transmission Right of Way Clearing:
This captures all charges for activities related to cutting, clearing, herbicide application and danger tree removal on substation supply lines up to 46 kV.

Other Police Detail Expenses:
This captures charges for all O&M police detail expenses not associated with Planned Cycle Trim.

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1.0 INTRODUCTION

This document describes the Distribution Planning Criteria and Strategy that will be used by the Liberty Utilities Engineering Department to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA"). A PSA is a group of distribution facilities, including substations, feeders, transformers, and sub-transmission lines, within a specific geographic area that are interconnected and are studied as a group. There are four PSAs in Liberty's service territory: Salem, Lebanon, Bellows Falls, and Monroe. See Attachment A for Liberty Utilities Planning Study Area Map. The review and evaluation of each PSA is to be documented in a report ("Distribution PSA Study") that describes the assumptions, procedures, economic comparison, conclusions, and recommendations for the PSA. Liberty will conduct a PSA Study periodically, or when conditions within the PSA change, such as: changes in overall PSA demand forecast; changes in how load is distributed within the PSA; significant load additions; and/or other changes in conditions that warrant a PSA Study.

When preparing a PSA Study, Liberty will consider wires and non-wires alternatives to address system needs, such as those listed in Table 1 below.

Table 1. Distribution System Planning Alternatives

Wires Alternatives	Non-Wires Alternatives
• Load Balancing • Power Factor Improvement • Reconductoring/Recabling • Circuit and Substation Equipment Upgrades • Voltage Conversions (e.g. 4kV to 13.2kV) • Feeder reconfigurations	• Distributed Generation • Controllable Load Curtailment • Energy Efficiency • Energy Storage Devices • Demand Side Management • Distribution Automation • Smart Grid Solutions (Ex: Dynamic Ratings, Real Time Load Transfers and Capacitor Activation, etc.)

1.1 Objective

The goal of these planning criteria is to provide adequate capacity for safe, reliable, and economic service to customers with minimal impact on the environment. To achieve that goal, the distribution system is planned, measured, and operated with the objective of providing electric service to customers under system intact conditions (i.e., "normal") and first contingency conditions ("N-1").

1.2 Planning Criteria

Since the purchase of the New Hampshire electric assets from National Grid in 2012, Liberty Utilities has refined the distribution planning criteria to better fit Liberty's strategy of having sufficient capacity available to meet changes in demand, including new customer demand, to improve operations during emergency conditions, and to allow more time for the planning, analysis, and construction, as needed, of new facilities. In addition, the refinements reflect the operating parameters of Liberty's smaller distribution footprint and resource base.

The criteria shall be reviewed and refined further, as needed, to reflect any major changes in standards or operating criteria.

2.0 PLANNING CRITERIA SUMMARY

The planning criteria are used to review and evaluate the performance of Liberty's distribution system for each Planning Study Area ("PSA"). The planning criteria are a critical input to identifying system deficiencies in Liberty's distribution planning process. See Figure 1 for the planning process. The planning criteria described in this document provide the framework to identify normal and emergency conditions, the acceptable equipment ratings under these conditions, and the corrective action required when the criteria are exceeded. Planning Criteria are distinguished from Planning Guidelines. Planning Guidelines are broader goals which should be met over time in the pursuit of achieving a reliable, economic distribution system, but may not necessitate immediate action.

For normal loading conditions, the planning criteria are based on feeders, supply lines, and transformers to remain within 100% of normal ratings at all times.

For N-1 contingency situations, the planning criteria are based on interrupted load returning to service via system reconfiguration through switching, installation of temporary equipment such as mobile transformers or generators, and/or by repair of a failed device. Where practical, at least three feeder ties are planned for each feeder for switching flexibility and are integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Table 2 shall guide planning on the distribution system:

Table 2. Distribution System Design Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	Load must be transferred to other supply lines in the area to within their LTE rating. Repairs are expected to be made within 24 hours Evaluate alternatives if more than 120 MWhr of load at risk results post contingency switching.	Load must be transferred to nearby transformer to within their LTE rating. Repairs or installation of Mobile Transformer expected to take place within 24 hours. For transformers larger than 10 MVA nameplate, evaluate alternatives if more than 180 MWhr of load at risk results following post-contingency switching.	Load must be transferred to nearby feeders to within their LTE rating. Repairs expected to be made within 24 hours.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	As Needed – Typically 15 min for OH conductors and 1-24 hours for UG cables.	Loads must be reduced within 15 minutes to operate within their LTE rating	As Needed – Typically 15 min for OH conductors and 1-24 hours for UG cables.

3.0 DESCRIPTION OF THE DISTRIBUTION SYSTEM

Liberty's distribution system consists of lines and equipment operated at a voltage at or below 23 kilovolts ("kV"). The components of the distribution system include distribution substations, sub-transmission lines, and distribution circuits or feeders.

3.1 Distribution Substations

The distribution substations within Liberty Utilities are a mixture of stations with one, two, or three or more transformers. A typical substation consists of 23/13 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders. Some distribution substations are supplied by the 115 kV circuits and are jointly owned by Liberty Utilities and National Grid. Liberty Utilities and National Grid maintain approximately 16 distribution substations containing approximately 26 power transformers in the Liberty Utilities service territory. Liberty Utilities anticipates that the distribution planning criteria will, in general, be applied to both Liberty and New England Power assets serving Liberty customers. However all existing 115kV transformers serving Liberty customers are owned and maintained by National Grid. System Non-Wires and Wires solution alternatives will be developed along the lines of these criteria recognizing, however, the unique nature of transmission supply contingencies on the distribution system.

3.2 Sub-Transmission System

The sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are considered neither bulk transmission nor distribution. The voltages for Liberty's sub transmission system include 23 kV and 13.8 kV. The voltages for the National Grid sub transmission system includes 46 kV. The sub-transmission system is designed in an open loop or "radial" system and, generally provides a redundant supply for distribution substations. The sub-transmission system is presently designed with conductors ranging from 336.4 ACSR to 1113 thousand circular mils ("kcmil") overhead conductors, and from 500 to parallel 1000 kcmil copper underground conductor. There are eight sub-transmission lines that are maintained by Liberty Utilities.

3.3 Distribution Feeders

The distribution feeders from each substation are in a "radial" configuration with provisions for manual or automatic transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductors. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses and trip savers on the branch circuits. The Liberty Utilities distribution system is comprised of approximately 41 feeders ranging from 2.4kV to 13.2kV.

4.0 EQUIPMENT RATINGS

Thermal limits are recognized for all system elements in conducting planning studies. Current in equipment and lines are limited so that voltage drops are held to reasonable values so that conductors will not be severely annealed or damaged, so that switches, connectors, etc. will not be overloaded, and so that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures; 2) load cycles; 3) wind velocities; and 4) potential loss of life of equipment.

Liberty's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

4.1 Overhead Conductors

The current carrying capacity (also known as, "ampacity") of an overhead conductor may be limited either by conductor clearances or maximum allowable operating temperature under a predefined set of reasonably severe summer or winter ambient conditions. The Company's Overhead Construction Standards book lists maximum ratings not to be exceeded for each conductor for normal and emergency operation.

As part of system operation, standard conductor sizes for overhead distribution construction of #2 AAAC, 1/0 AAAC and 477 AAAC or equivalent tree wire have been selected by Liberty Utilities.

The following general guidelines were developed for 13.2 kV overhead distribution lines:

- New single-phase overhead distribution lines should be constructed with #1/0 AAAC, and new single-phase underground distribution lines should be constructed with #2 AWG AL for loads less than 500kW.
- The single-phase lines should be reconductored to three-phase wherever needed based on operating conditions, phase imbalance, and voltage drop.
- New three-phase overhead distribution lines and/or future distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:
  - For loads less than 3,000 kW: 1/0 AAAC
  - For loads greater than 3,000 kW: 477 AAAC
- The single-phase and three phase lines should be reconductored with covered tree conductor or spacer cable wherever needed, based on operating conditions in tree prone areas.

The maximum ampacity of an overhead conductor is estimated for Normal (continuous) and Long-Time Emergency (LTE) operations for summer and winter conditions.

4.1.1 Normal Capability

The Normal rating shall be interpreted as the maximum value for normal peak loads on all new and rebuilt feeders. The temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, and covered conductors.

4.1.2 Long-Time Emergency Capabilities (24 hours)

The LTE rating shall be interpreted as the absolute maximum ampacity allowed for a given conductor. This ampacity should not be exceeded at any time unless an appropriate engineering review has been conducted. The temperature limit for LTE for 100% ampacity for operating conductor at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for bare and spacer cable, tree wire, and covered conductors. Higher temperatures for bare conductors may be considered as field conditions permit following approval by the Manager of Engineering - Standards, Policies, and Programs.

4.1.3 Short-Time Emergency Capability (As needed)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. Loads must be reduced within 15 minutes to operate within the LTE rating. Ratings for other short time emergency durations are approved and provided by the

Engineering department on a case by case basis after an appropriate engineering review has been conducted.

4.2 Underground Cables

Underground distribution line ratings were derived from the October 1957 AIEE paper titled, "The Calculation of the Temperature Rise and Load Capability of Cable System," by J.H. Neher and M.H. McGrath. These calculations integrate all aspects of the cable system design such as conductor material, conductor size, insulation, properties, insulation thickness, cable type, shield connections, load characteristics, installation conditions, and environment. Cable ampacities are based on normal and emergency operating conditions. Normal cable ampacities are based on a 90° insulation operating temperature, while emergency cable ampacities are based on 130° insulation operating temperature. The Company's underground construction standards book provides estimates of cable ampacity for common sizes and configuration of main line cables. Given the many different aspects of a cable system, specific cable ratings are typically derived using computer software such as Synergee Electric or PC Amp.

New three-phase underground distribution lines or future three-phase underground distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:

- For loads less than 2000 kW: #2 AWG AL
- For loads greater than 2000 kW: #4/0 AWG CU
- For loads greater than 3500 KW or part of a feeder mainline: 500 MCM CU
- For feeder cable getaways: 1000 MCM CU

Ampacities are defined for underground cables as follows:

4.2.1 Normal Ampacity (Continuous)

This is the maximum loading on the cable that does not cause the conductor temperature to exceed its design value at any time.

4.2.2 100-300 Hour Ampacity (LTE)

This is the maximum emergency loading on the cable that does not cause the conductor temperature to exceed its applicable emergency value over a period of several consecutive 24-hour load cycles. At the end of the emergency time period, the load on the cable must be reduced to a value within its normal ampacity.

4.2.3 One-Hour to 24-Hour Emergency Ampacities (STE)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are the maximum emergency loadings on the cable that do not cause the conductor temperature to exceed its allowable emergency value at any time during the period. At the end of the emergency time period, the load on the cable must be reduced so that the peak load in the next load cycle does not exceed the LTE ampacity (defined above).

4.3 Transformers

Distribution substation transformers are rated for loading according to the American National Standards Institute ("ANSI") standards for maximum internal hot spot and top oil temperatures. This is detailed in the Institute of Electrical and Electronics Engineers ("IEEE") Guide for Loading Mineral-Oil-Immersed Power Transformers up to and including 100 MVA with 55°C or 65°C winding temperature rise (ANSI/IEEE C57.91 latest version). The manufacturer's factory test data and the experienced 24-hour loading curve data are used in an iterative computer program that calculates allowable loading levels.

The transformer's "ratings" for the Normal ("N"), Long Term Emergency ("LTE"), and Short Term Emergency ("STE") load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer's life caused by its operation at the criteria temperatures for a specified duration, and on a defined load curve. Three categories of transformer capabilities are defined below:

4.3.1 Normal Capability

Winter normal and summer normal capabilities are based on a normal daily load cycle and on the maximum 24-hour average ambient temperature for the period involved. The maximum load for Normal operation of the transformer is determined and set when the operation of the transformer at that level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or the Top Oil Temperature exceeds 110 °C, or the Hot Spot Copper temperature exceeds 180 °C. Conditions above any of these limitations will result in a shortening of the transformer service life beyond prescribed design levels and/or physical damage to the equipment.

4.3.2 Long-Time Emergency Capabilities (1 hour to 300 hours)

These capabilities are based on a normal daily load cycle, with the emergency load increment added. The maximum 24-hour average ambient temperature is used for the appropriate season. The LTE rating of a substation transformer is determined and set when the 24 hour operation of the transformer, with that additional load in each of the hours in the 24 hour load cycle curve, causes a cumulative (24 hour) 3.0% loss of transformer life, or the Top Oil temperature to exceed 130 °C, or the hot spot copper temperature to exceed 180 °C.

4.3.3 Short-Time Emergency Capability (15 minutes or less)

The STE rating of a transformer is determined and set when the one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% Loss of Transformer Life or a hot spot copper temperature exceeding 180°C. However, the maximum STE rating is limited to a value equal to twice the transformer's "nameplate" rating (i.e., 200%).

4.4 Other Equipment

In addition to the items above, normal and emergency capabilities are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers. Emergency capabilities usually involve elevated temperatures with some potential loss of equipment life. However, any circuit rating may be limited by other circuit equipment such as circuit breakers, disconnects, regulators, et cetera. These ratings are generally based on the allowable maximum temperature of the equipment. The facility (feeder, sub transmission line, and/or transformer) rating is determined by identifying the "limiting device" and applying the rating criteria for that device or equipment.

4.4.1 Distribution Overhead Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
145%	180%	160%	200%

4.4.2 Distribution Single Phase Padmount Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
140%	160%	140%	160%

4.4.3 Distribution Three Phase Padmount Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
120%	140%	120%	140%

4.4.4 Distribution Step-Down Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
110%	110%	110%	110%

4.4.5 **Circuit Breakers / Reclosers**

The following generic ratings in % of nameplate are used: NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
107%	123%	115%	130%

4.4.6 **Voltage Regulators**

The following generic regulator ratings in % of nameplate for 10% regulation are used:

55ºC INSULATION SYSTEM				**65ºC INSULATION SYSTEM**			
NORMAL		EMERGENCY		NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
125%	148%	125%	148%	141%	160%	141%	160%

4.4.7 **Disconnect Switches**

The following generic air switches ratings in % of nameplate:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
113%	134%	139%	147%

4.5 Equipment Rating Criteria Summary

The major equipment ratings to be used by planning engineers relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for feeders, sub transmission lines, and transformers may be applied for the time associated with each rating. Table 3 summarizes the durations for emergency loading that system operators must be aware of, including the limiting factor involved in any contingency. There is also a short time emergency (STE) rating that is mainly used for transformers and must not exceed

200% of nameplate rating. Table 4 summarizes the Equipment Rating criteria, as described in more detail above.

Table 3. Facility Rating Durations

Equipment	Normal	LTE	STE
Feeders	Continuous	24 Hours	As Needed, Typically 15 Minutes
Sub Transmission lines	Continuous	24 Hours	As Needed, Typically 15 Minutes
Transformer	Continuous	1 - 300 Hours	15 Minutes

Table 4. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**	**Duration**	**Design Criteria**
Normal	Continuous	•The maximum value for normal peak loads on all new and rebuilt feeders •Temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, & covered conductors	Continuous	•Maximum loading that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle •Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	•Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or •The Top Oil Temperature exceeds 110 °C, or •The Hot Spot Copper temperature exceeds 180 °C
LTE	24 Hours	•The absolute maximum ampacity allowed for a given conductor and should not be exceeded at any time. •Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, & covered conductors	100 - 300 Hours	•Maximum loading that does not cause the conductor temperature to exceed its design value over several consecutive 24-hour load cycles. •Emergency cable ampacities are based on 130° insulation operating temperature.	24 Hours	•Level for the peak hour with the emergency load added in the 24-hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer life, or •the Top Oil Temperature exceeds 130 °C, or •the Hot Spot Copper temperature exceeds 180 °C
STE	As Needed	•Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	•Maximum loading that does not cause the conductor temperature to exceed its allowable emergency value at any time during a 24-hour load cycle. •Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	•The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer Life, or •A hot spot copper temperature exceeding 180°C. •Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

5.0 DISTRIBUTION SUBSTATION TRANSFORMER LOADING CRITERIA

The ratings of transformers are calculated from their thermal heat transfer characteristics and the expected electric loading experience over a 24-hour cycle. All distribution substation transformer bank ratings are evaluated seasonally for their summer and winter values.

5.1 Normal Operation Design Criteria

Normal operation is the condition under which all electric infrastructure equipment is fully functional. A substation transformer will not be loaded above 100% of its Normal rating during non-contingency operating periods.

5.2 First Contingency Emergency Design Criteria

First contingency operation is the condition under which a single element (distribution substation transformer) is out of service. For first contingency emergency conditions involving the loss of one distribution substation transformer larger than 10 MVA, the following system design criteria applies:

- In cases where a first contingency situation causes the LTE rating of the remaining transformer to be exceeded, all load above the LTE rating of the remaining transformers must be transferred to neighboring facilities or shed 15 minutes without exceeding the LTE rating of the substation transformers or distribution circuits receiving the load.
- In cases where a first contingency situation will cause the STE rating of a remaining transformer to be exceeded, load must be immediately reduced (dropped/shed) to a level within the STE. All load between the LTE and STE ratings, and any load that was initially shed to get the remaining transformer below its STE rating, must be transferred to peripheral facilities without exceeding the LTE rating of the substation transformers or the distribution circuits receiving the load.
- Repairs or the installation of mobile equipment are expected to be made within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 180 MWhrs. If more than 180 MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

5.3 Automatic Transfer of Load

Locations with two or more transformers at a substation utilize automatic bus transfers. Based on the loading limitations of Section 5.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during a first contingency. Cases where automatic restoration is disabled will be communicated with Electric Control as part of an annual summer preparedness review. Disabling of automatic bus transfer schemes will not be considered as a permanent solution to a criteria violation.

6.0 DISTRIBUTION CIRCUIT LOADING CRITERIA

6.1 Normal Operation Design Criteria

A feeder circuit should be loaded to no more than 100% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions and/or provides capacity to serve new business or commercial applications in a timely manner.

6.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a distribution circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. For the loss of a distribution feeder, the following criteria apply:

- After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. All adjoining tie feeders can be loaded to their maximum LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.

6.3 First Contingency Emergency Design Guidelines

The following guidelines shall apply to distribution feeders:

- If more than 16 MWh of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- Distribution feeders should be limited to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or 2,000kVA of load between disconnecting devices.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- For a typical Liberty owned 10 MW feeder, approximately 8 MW would need to be restored via switching within one hour. The remaining 2 MW would be restored after

repairs within 4 hours. Where longer repair times are needed, such as for a cable getaway fault, the load out of service should be reduced to 1 MW.

6.4 Automatic transfer on feeders

In some cases it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers or due to automatic reclosing loop schemes in the distribution lines.

6.5 Primary Circuit Voltage Criteria

The normal and emergency voltage to all customers shall be in line with limits specified by the state of New Hampshire and within the limits of ANSI C84.1-2016.

These upper and lower voltage ANSI limits, as measured at the customer's meter, are listed below in Table 5:

Table 5. Voltage Requirements for LU

For 120 V – 600 V Systems				
Nominal Voltage (V)	**Service Voltage (V)**			
	Range A		**Range B**	
	Max	Min	Max	Min
120	126	114	127.2	104.4
240	252	228	254.4	208.9
480	504	456	508.8	417.6

Source: ANSI

Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or pad mounted line regulators.

Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 5 above are maintained. The ultimate goal is to keep all customers' service voltages within accepted limits. From a supply point of view, the acceptability of voltage regulation is determined at the distribution substation buses. At substations with feeder or bus regulating equipment, the regulation (the extreme range of voltages expressed as a percentage of normal peak load voltage) should be no greater than 10 percent for normal and 15 percent for emergency conditions on the source side of the regulating equipment. Most substation regulating equipment has a range of 20 percent. Under normal conditions, therefore, half the regulator range can compensate for variations in supply voltage, leaving the other half available for voltage drops on the distribution feeders. The substation transformer taps are chosen to allow this control.

6.6 Distribution Circuit Phase Imbalance Criteria

Adding new customer loads to the distribution circuit must be done in the manner to minimize phase imbalance on the distribution system. These criteria are established to limit the load imbalance among the three phases of a primary distribution circuit. Such an imbalance gives rise to return current through the neutral conductor which contributes towards additional losses and voltage drop. Heavily loaded phases overstress the conductors reducing their life and can also lead to their eventual burn down or connector overheating, even at low loadings of the circuit. A high imbalance could also lead to the ground relay operating on the feeder breaker. These criteria call for the correction of phase imbalances of existing and new distribution circuits. Phase imbalance is defined on the basis of connected KVA (CKVA) load for that circuit as:

$$\%imbalance = \frac{(phase\ load - average\ phase\ load)}{average\ phase\ load} X\ 100$$

Two criteria should be met for the circuit to be considered for corrective action:

1. The calculated neutral current should not exceed 30% of the feeder ground relay pickup setting;

2. The loading between the low and high phase should not exceed 100A.

Any circuit violating these criteria will be monitored to get actual loading data, and will be corrected if the imbalance is verified. Any new load addition to a circuit should adhere to these criteria.

For all new single phase load additions, the new installation is connected to the phase with the least connected KVA, if it is available, to maintain a balanced circuit.

7.0 SUB-TRANSMISSION LINE LOADING CRITERIA

7.1 Normal Operation Design Criterion

A sub transmission line should be loaded to no more than 100% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent supply lines during first contingency N-1 conditions.

7.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a supply circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. For the loss of a supply line, the following criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 24 hours (12 hour for overhead, 24 hours for underground).
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- For a typical Liberty-owned sub-transmission supply line consisting of either 13.8 kV or 23 kV, the quantity of load at risk of being out of service following post contingency switching should be limited to 120MWhr of load at risk at peak load periods for a single fault. Alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- In the case of parallel underground conductors, depending on the protection and operating scheme, N-1 contingency analysis may include the initial loss of both parallel phases. However, when determining repair and restoration times for contingency analysis, operating capabilities such as the ability to isolate paralleled cables using disconnects and partially restoring one of two cables will be considered.

7.3 Automatic Transfer of Load

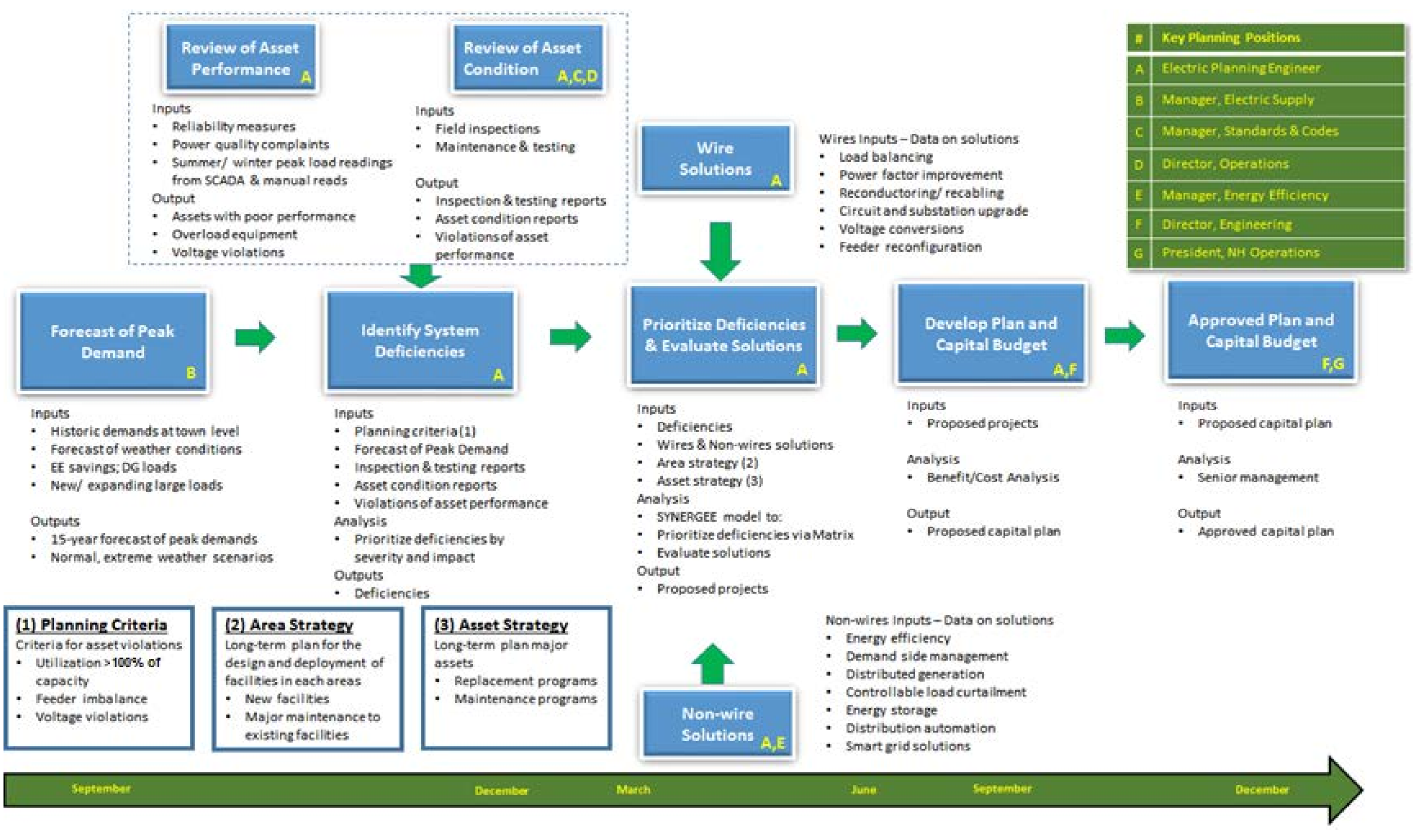
Auto transfer of load on the sub-transmission may be employed, but may not exceed the LTE ratings of the remaining supply lines. When available, SCADA control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed. Cases where automatic restoration is disabled will be communicated with Electric Control as part of an annual summer preparedness review. Disabling of automatic bus transfer schemes will not be considered as a permanent solution to a criteria violation.

8.0 PLANNING STUDIES

A planning study area (“PSA”) within Liberty Utilities is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. PSA’s in Liberty’s service territory are totally independent from each other. A listing of the planning study areas that exist in the Liberty service territory are presented in Attachment A.

Liberty conducts an annual capacity planning process covering a 5 year period with inputs from various stakeholders that is intended to meet future customer demands, identify thermal capacity constraints, ensure adequate delivery voltage, and assess the capability of the system to respond to contingencies that might occur. The distribution planning process is illustrated in Figure 1 below:

Figure 1. Distribution Planning Process Map and Timeline



8.1 Electric System Planning Criteria and Methodology

8.1.1 Modeling Guidelines

As shown in Figure 1 above, the planning process for designing the Distribution System begins with the load forecast. The PSA load forecast is updated annually. The load forecast at the system level is based on econometric models, and is developed on both a weather-normalized and weather-probabilistic basis. Currently, the Liberty distribution system is modeled for a "peak hour" load level that has a 10% probability of occurrence such that those weather conditions are expected to occur once in 10 years. Specific major known or planned load additions are factored into the load forecast. Historical DSM and DG along with specific DSM/DG installations are also factored into the forecast. The resultant load forecasts are utilized in two types of planning studies which assess the ability of the distribution system to meet future customer load requirements. These studies include (1) Area Studies and (2) Interconnection Studies, and are described below.

Load flow analyses are used to determine expected circuit overloads and to evaluate alternatives for system reinforcements. Liberty utilizes the Synergee computer application to model load flows in the distribution system.

Substation circuit breakers are modeled using their rated interrupting capability in the ASPEN™ short circuit analysis computer program. Any breaker that meets or exceeds its rated interrupting capability is targeted for replacement.

Area studies

Area studies are generally 15-year forecast time frames and address specific load areas, including the area supply system, substations, and distribution feeders.

Interconnection studies

System interconnection studies are designed to determine the interconnection facilities and system reinforcements required for specific generation and distribution growth projects to enable them to be effective over the life of the project.

9.0 SYSTEM RELIABILITY

The supply and distribution system in the Liberty system are designed to limit the interruption of energy delivery for a loss of any single element.

The indices of service reliability are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). The SAIDI measures the total duration of an interruption for the average customer during a given time period. The SAIFI measures the average number of times that a customer experiences an outage during a given time period.

The supply and distribution systems shall be designed so that the annual SAIDI and SAIFI do not exceed the five-year rolling averages, excluding severe weather related events, and support a nominal improving five-year reliability trend. When an exceedance does occur, efforts shall be made in the subsequent year(s) to further improve reliability performance to an improving trend level.

10.0 OTHER CONSIDERATIONS

The planning engineer must consider the effect of each plan on all aspects of system design. These include:

- Protection: Protection or Coordination studies are performed when it is needed to adjust relay settings at substations to increase rating of the facility. Settings are carefully selected to avoid mis-coordination and trips due to load imbalance.
- Operation and Maintenance (“O&M”): O&M is taken into account when ranking different project alternatives.
- System Power Factor: Liberty will strive to maintain a 98% power factor at the substations to provide quality power to its customers and limit system losses via the addition of new capacitor banks. In addition, annual Surveys for system power factor will allow Liberty to properly manage reactive support by adjusting settings from capacitor bank controls.
- Short Circuit Duty: Substation circuit breakers are modeled using their rated interrupting capability in the ASPEN™ short circuit analysis computer program. Any breaker that meets or exceeds its rated interrupting capability is targeted for replacement.

11.0 BENEFITS OF PLANNING CRITERIA STRATEGY

The most recent changes to these planning criteria are to move Liberty’s criteria closer to that of the other utilities in the region. This planning strategy provides a documented approach to managing the Liberty system consistent with the approach of other local utilities, a goal of the New Hampshire regulator. This will better support the investment plans needed to implement the loading guidelines outlined in the strategy.

The planning strategy provides a consistent approach for feeder/substation/supply line and PSA loading analysis across Liberty. All studies being conducted under one set of criteria will make way for a consistent reference for ranking studies as part of the budgeting process. This will result in a more efficient organization and a streamlined flow of information from the planning study results into the budgeting process.

Liberty Utilities WATER | GAS | ELECTRIC		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
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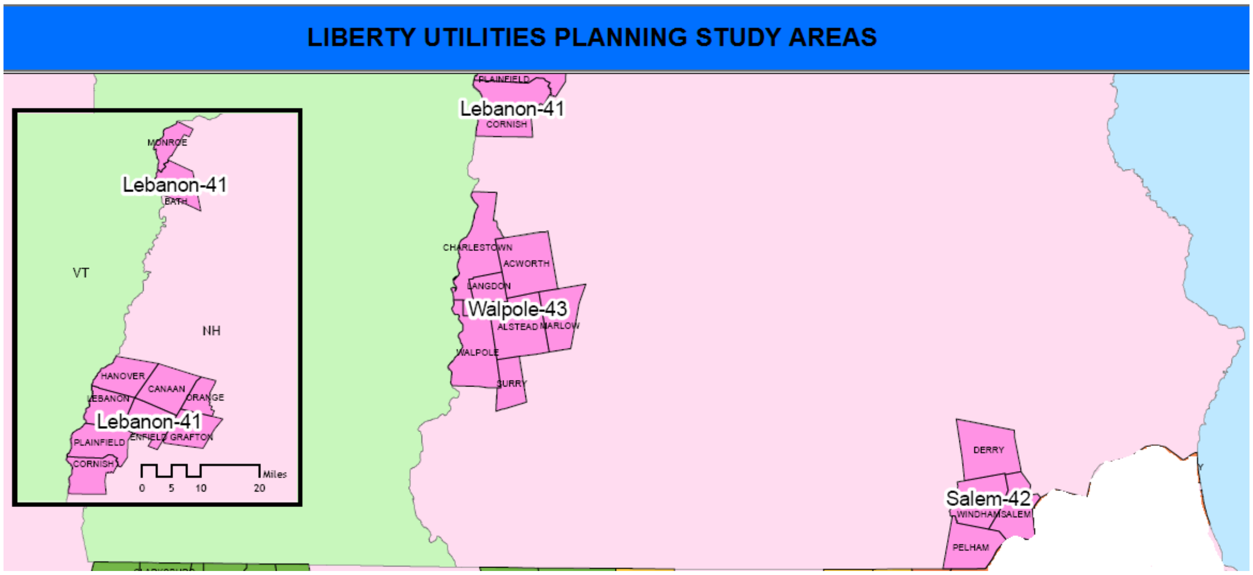
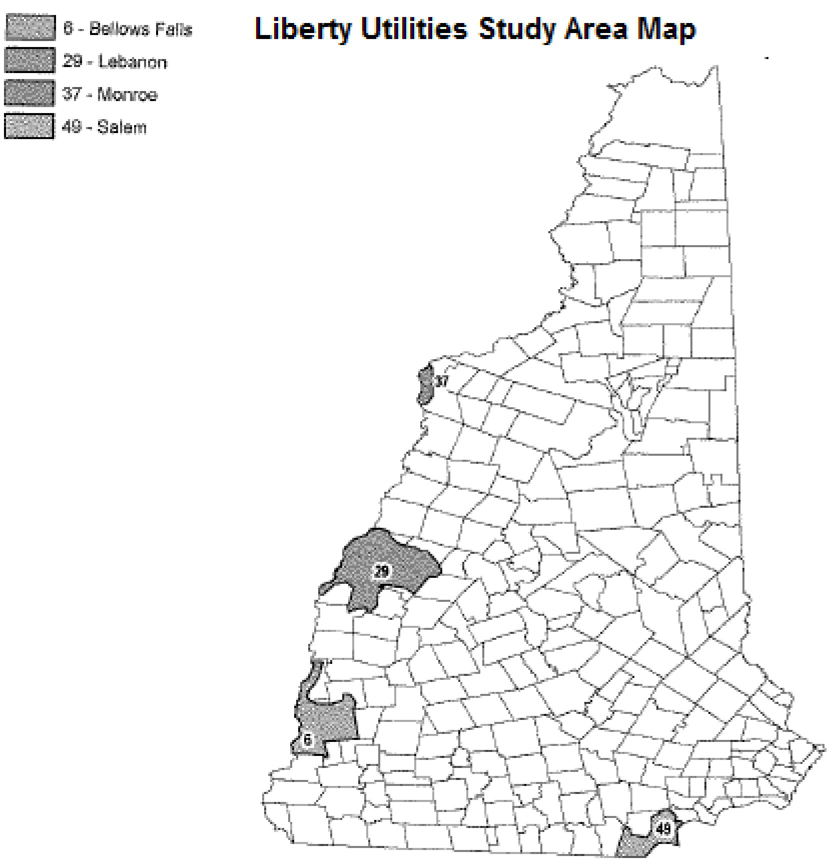
Attachment A – Liberty Utilities Planning Study Area Map





Attachment B – Summary of Planning Criteria Changes

2016 Criteria	2020 Criteria	National Grid Criteria
During normal operation, all distribution feeders to remain within 75% of normal ratings.	**During normal operation, all distribution feeders to remain within 100% of normal ratings.**	During normal operation, all distribution feeders to remain within 100% of normal ratings.
During normal operation, all sub-transmission lines to remain within 90% of normal ratings.	**During normal operation, all sub-transmission lines to remain within 100% of normal ratings.**	During normal operation, all sub-transmission lines to remain within 100% of normal ratings.
During normal operation, all transformers to remain within 75% of normal ratings.	**During normal operation, all transformers to remain within 100% of normal ratings.**	During normal operation, all transformers to remain within 100% of normal ratings.
No Change	**Part of a Planning Design Guideline**	For the loss of a distribution feeder, if more than 16MWhrs of load at risk results for a single feeder fault evaluate alternatives to mitigate.
For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 1.5MW combined. If more than 36MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	**For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 120 Mwhr. If more than 120 MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.**	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.
For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5MW combined. If more than 60MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	**For the loss of a transformer above 10 MVA, the quantity of load at risk of being out of service following post contingency switching should be limited to 180 MWhr. If more than 180 MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.**	For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 10MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.

Every effort must be made to return the failed sub-transmission line to service within 12 hours.	**Every effort must be made to return the failed sub-transmission line to service within 12 hours for OH wires and 24 hours for UG cables.**	Every effort must be made to return the failed sub-transmission line to service within 24 hours.
N/A	Every effort must be made to return the failed distribution feeder to service within 24 hours.	Every effort must be made to return the failed distribution feeder to service within 24 hours.

Approved by: ____ Date: _____________________

Charles Rodrigues
Director of Engineering
Liberty Utilities

Liberty Utilities, NH
Granite State Electric
Revenues Subject to Decoupling

Line No.	Estimated Distribution Revenues	Source	Decoupling Year N/A Effective July 1, 2020	1 Effective July 1, 2021	2 Effective July 1, 2022
1	Base	Settlement Agreement Attachment 5 line 115	$ 43,708,498	$ 45,317,940	$ 47,312,437
2	Step	Settlement Agreement Attachment 1 line 40	$ 1,349,466	$ 1,783,994	$ 1,800,000
3	Reliability Enhancement Program	DE 20-036	$ 210,503	$ 210,503	$ -
4	Recoupment	Settlement Agreement Attachment 3 Line 7 / 2	$ 917,996	$ 917,996	$ -
5	Rate Case Expense	Settlement Agreement Attachment 6 Line 6 / 2	$ 276,821	$ 276,821	$ -
6	Total		$ 46,463,284	$ 48,507,254	$ 49,112,437

Line No.	Less: Street Lighting Estimated Distribution Revenues	Source / Calculation	Effective July 1, 2020	Effective July 1, 2021	Effective July 1, 2022
7	Base	Settlement Agreement Exhibit 5 line 115	$ 1,226,293	$ 1,271,448	$ 1,327,406
8	Step	(Line 7 / Line 1) * Line 2	$ 37,861	$ 50,052	$ 50,501
9	Reliability Enhancement Program	(Line 7 / Line 1) * Line 3	$ 5,906	$ 5,906	$ -
10	Recoupment	(Line 7 / Line 1) * Line 4	$ 25,755	$ 25,755	$ -
11	Rate Case Expense	(Line 7 / Line 1) * Line 5	$ 7,767	$ 7,767	$ -
12	Total		$ 1,303,582	$ 1,360,928	$ 1,377,907

Line No.	Estimated Distribution Revenues Subject To Decoupling	Source / Calculation	Effective July 1, 2020	Effective July 1, 2021	Effective July 1, 2022
13	Base	Line 1 - Line 7	$ 42,482,205	$ 44,046,492	$ 45,985,031
14	Step	Line 2 - Line 8	$ 1,311,605	$ 1,733,942	$ 1,749,499
15	Reliability Enhancement Program	Line 3 - Line 9	$ 204,597	$ 204,597	$ -
16	Recoupment	Line 4 - Line 10	$ 892,241	$ 892,241	$ -
17	Rate Case Expense	Line 5 - Line 11	$ 269,054	$ 269,054	$ -
18	Total		$ 45,159,702	$ 47,146,327	$ 47,734,530

Line No.	Rate Year (No Decoupling) Allowed Revenue Requirement 7/1/2020 - 6/30/2021	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	Total
1	Distribution Revenue Requirement	$20,685,493	$310,153	$9,891,187	$5,436,475	$5,313,487	$825,801	$19,608	$ 42,482,205
2	Step Increase	$638,649	$9,576	$305,383	$167,847	$164,050	$25,496	$605	$ 1,311,605
3	Reliability Enhancement Program	$99,623	$1,494	$47,637	$26,182	$25,590	$3,977	$94	$ 204,597
5	Recoupment	$434,451	$6,514	$207,742	$114,181	$111,598	$17,344	$412	$ 892,241
6	Rate Case expenses	$131,008	$1,964	$62,644	$34,431	$33,652	$5,230	$124	$ 269,054
7	**Total Target Revenues**	$21,989,223	$329,701	$10,514,593	$5,779,116	$5,648,377	$877,848	$20,844	$45,159,702

Line No.	Decoupling Year 1: Allowed Revenue Requirement 7/1/2021 - 6/30/2022	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	Total
8	Distribution Revenue Requirement	$21,447,178	$321,574	$10,255,402	$5,636,658	$5,509,141	$856,209	$20,330	$ 44,046,492
9	Step Increase	$844,293	$12,659	$403,716	$221,894	$216,874	$33,706	$800	$ 1,733,942
10	Reliability Enhancement Program	$99,623	$1,494	$47,637	$26,182	$25,590	$3,977	$94	$ 204,597
11	Recoupment	$434,451	$6,514	$207,742	$114,181	$111,598	$17,344	$412	$ 892,241
12	Rate Case expenses	$131,008	$1,964	$62,644	$34,431	$33,652	$5,230	$124	$ 269,054
13	**Total Target Revenues**	$22,956,553	$344,205	$10,977,141	$6,033,346	$5,896,855	$916,466	$21,761	$47,146,327

Line No.	Decoupling Year 2: Allowed Revenue Requirement 7/1/2022 - 6/30/2023	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	Total
14	Distribution Revenue Requirement	$22,391,094	$335,727	$10,706,755	$5,884,734	$5,751,605	$893,892	$21,225	$ 45,985,031
15	Step Increase	$851,868	$12,773	$407,338	$223,884	$218,820	$34,008	$808	$ 1,749,499
16	Reliability Enhancement Program	$0	$0	$0	$0	$0	$0	$0	$ -
17	Recoupment	$0	$0	$0	$0	$0	$0	$0	$ -
18	Rate Case expenses	$0	$0	$0	$0	$0	$0	$0	$ -
19	**Total Target Revenues**	$23,242,962	$348,499	$11,114,093	$6,108,618	$5,970,425	$927,900	$22,032	$47,734,530

Liberty Utilities, NH
Granite State Electric
Sample Monthly Decoupling Calculation

Line No.	A	B	C	D	E	F	G	H	I	J
	Decoupling Year 1: 7/1/2021 - 6/30/2022		**Domestic**	**Domestic - Opt. Peak**	**General TOU**	**General Long Hour**	**General Service**	**Limited All Electric**	**Ltd Comm Space Heating**	**Total**
			DOD2	**D10**	**G01**	**G02**	**G03**	**T00**	**V00**	
	Bills	*(Estimated using Test Year Bills)*								
1		January	35,344	438	135	904	5,649	981	18	43,469
2		February	35,193	441	135	906	5,663	975	18	43,331
3		March	35,347	441	132	910	5,671	975	18	43,494
4		April	35,329	443	131	901	5,688	967	18	43,477
5		May	35,313	440	141	914	5,650	968	18	43,444
6		June	35,263	439	138	903	5,638	967	18	43,366
7		July	35,232	443	139	922	5,691	961	18	43,406
8		August	37,134	441	143	942	5,902	1,034	19	45,615
9		September	33,822	435	138	872	5,425	881	15	41,588
10		October	35,547	440	141	906	5,680	956	17	43,687
11		November	35,400	437	140	900	5,679	951	17	43,524
12		December	35,656	439	145	902	5,704	950	17	43,813
13			424,580	5,277	1,658	10,882	68,040	11,566	211	522,214
14	**Distribution Revenues**	*(Settlement Allowed)*								
15		January	$2,280,201	$37,543	$858,240	$487,065	$543,918	$123,795	$2,420	$4,333,182
16		February	$1,928,246	$34,840	$851,669	$487,433	$513,127	$101,549	$2,149	$3,919,013
17		March	$1,833,192	$31,117	$835,554	$496,589	$491,543	$92,884	$1,909	$3,782,788
18		April	$1,804,766	$29,341	$839,610	$481,315	$479,257	$81,933	$1,818	$3,718,040
19		May	$1,629,793	$24,371	$868,490	$502,654	$447,122	$62,414	$1,520	$3,536,364
20		June	$1,794,535	$23,544	$956,272	$515,365	$474,706	$55,806	$1,551	$3,821,779
21		July	$2,043,066	$26,615	$1,014,316	$539,629	$505,543	$58,687	$1,907	$4,189,763
22		August	$2,239,627	$29,613	$1,066,496	$551,612	$547,086	$63,422	$2,221	$4,500,077
23		September	$2,023,475	$27,856	$1,008,290	$511,221	$504,354	$56,197	$1,519	$4,132,912
24		October	$1,653,552	$22,849	$913,896	$503,683	$443,345	$53,914	$1,454	$3,592,693
25		November	$1,690,037	$24,820	$852,687	$474,004	$432,829	$69,335	$1,355	$3,545,067
26		December	$2,036,063	$31,695	$911,619	$482,776	$514,028	$96,529	$1,939	$4,074,649
27			22,956,553	344,204	10,977,139	6,033,346	5,896,858	916,465	21,762	47,146,327
28	**Monthly Target Revenue Per Customer (Monthly Target 'RPC')**									
29	**1**	January	$64.51	$85.71	$6,357.33	$538.79	$96.29	$126.19	$134.44	
30	**2**	February	$54.79	$79.00	$6,308.66	$538.01	$90.61	$104.15	$119.39	
31	**3**	March	$51.86	$70.56	$6,329.95	$545.70	$86.68	$95.27	$106.06	
32	**4**	April	$51.08	$66.23	$6,409.24	$534.20	$84.26	$84.73	$101.00	
33	**5**	May	$46.15	$55.39	$6,159.50	$549.95	$79.14	$64.48	$84.44	
34	**6**	June	$50.89	$53.63	$6,929.51	$570.73	$84.20	$57.71	$86.17	
35	**7**	July	$57.99	$60.08	$7,297.24	$585.28	$88.83	$61.07	$105.94	
36	**8**	August	$60.31	$67.15	$7,458.01	$585.58	$92.70	$61.34	$116.89	
37	**9**	September	$59.83	$64.04	$7,306.45	$586.26	$92.97	$63.79	$101.27	
38	**10**	October	$46.52	$51.93	$6,481.53	$555.94	$78.05	$56.40	$85.53	
39	**11**	November	$47.74	$56.80	$6,090.62	$526.67	$76.22	$72.91	$79.71	
40	**12**	December	$57.10	$72.20	$6,287.03	$535.23	$90.12	$101.61	$114.06	
41										
42	**Normalized Test Year Revenues (used to spread Annual Allowed Revenues Among the Classes)**		D-05 & -06	D-10	G-1	G-2	G-3	T	V	Total
43		Jan-18	$1,891,081	$31,136	$711,780	$403,946	$451,098	$102,669	$2,007	$3,593,716
44		Feb-18	$1,599,187	$28,894	$706,330	$404,252	$425,561	$84,220	$1,783	$3,250,227
45		Mar-18	$1,520,355	$25,807	$692,966	$411,845	$407,660	$77,033	$1,583	$3,137,249
46		Apr-18	$1,496,779	$24,334	$696,329	$399,178	$397,471	$67,951	$1,507	$3,083,549
47		May-18	$1,351,666	$20,212	$720,281	$416,875	$370,820	$51,763	$1,260	$2,932,877
48		Jun-18	$1,488,295	$19,526	$793,083	$427,417	$393,696	$46,282	$1,287	$3,169,586
49		Jul-18	$1,694,413	$22,074	$841,222	$447,540	$419,271	$48,672	$1,582	$3,474,773
50		Aug-18	$1,857,431	$24,560	$884,497	$457,478	$453,725	$52,599	$1,842	$3,732,132
51		Sep-18	$1,678,165	$23,102	$836,223	$423,981	$418,285	$46,607	$1,260	$3,427,623
52		Oct-18	$1,371,371	$18,950	$757,938	$417,729	$367,687	$44,713	$1,206	$2,979,594
53		Nov-18	$1,401,629	$20,584	$707,174	$393,114	$358,966	$57,503	$1,124	$2,940,094
54		Dec-18	$1,688,605	$26,286	$756,050	$400,390	$426,308	$80,056	$1,608	$3,379,303
55			$19,038,977	$285,466	$9,103,872	$5,003,744	$4,890,546	$760,069	$18,047	$39,100,722
56		Percent of Total	48.69%	0.73%	23.28%	12.80%	12.51%	1.94%	0.05%	100.00%
57										
58	Normalized Test Year Revenues		D-05 & -06	D-10	G-1	G-2	G-3	T	V	
59		Jan-18	9.93%	10.91%	7.82%	8.07%	9.22%	13.51%	11.12%	
60		Feb-18	8.40%	10.12%	7.76%	8.08%	8.70%	11.08%	9.88%	
61		Mar-18	7.99%	9.04%	7.61%	8.23%	8.34%	10.14%	8.77%	
62		Apr-18	7.86%	8.52%	7.65%	7.98%	8.13%	8.94%	8.35%	
63		May-18	7.10%	7.08%	7.91%	8.33%	7.58%	6.81%	6.98%	
64		Jun-18	7.82%	6.84%	8.71%	8.54%	8.05%	6.09%	7.13%	
65		Jul-18	8.90%	7.73%	9.24%	8.94%	8.57%	6.40%	8.77%	
66		Aug-18	9.76%	8.60%	9.72%	9.14%	9.28%	6.92%	10.21%	
67		Sep-18	8.81%	8.09%	9.19%	8.47%	8.55%	6.13%	6.98%	
68		Oct-18	7.20%	6.64%	8.33%	8.35%	7.52%	5.88%	6.68%	
69		Nov-18	7.36%	7.21%	7.77%	7.86%	7.34%	7.57%	6.23%	
70		Dec-18	8.87%	9.21%	8.30%	8.00%	8.72%	10.53%	8.91%	
71		Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

Liberty Utilities, NH
Granite State Electric
Sample Monthly Decoupling Calculation

Line No.	K	L	M	N	O	P	Q	R	S	T
	Hypothetical Actual		**Domestic**	**Domestic - Opt. Peak**	**General TOU**	**General Long Hour**	**General Service**	**Limited All Electric**	**Ltd Comm Space Heating**	**Total**
			DOD2	**D10**	**G01**	**G02**	**G03**	**T00**	**V00**	
	Bills		**1.0%**	**1.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**<--- Scenario Input**
1	**1**	January	35,697	442	135	904	5,649	981	18	43,826
2	**2**	February	35,545	445	135	906	5,663	975	18	43,687
3	**3**	March	35,700	445	132	910	5,671	975	18	43,851
4	**4**	April	35,682	447	131	901	5,688	967	18	43,834
5	**5**	May	35,666	444	141	914	5,650	968	18	43,801
6	**6**	June	35,616	443	138	903	5,638	967	18	43,723
7	**7**	July	35,584	447	139	922	5,691	961	18	43,762
8	**8**	August	37,505	445	143	942	5,902	1,034	19	45,990
9	**9**	September	34,160	439	138	872	5,425	881	15	41,930
10	**10**	October	35,902	444	141	906	5,680	956	17	44,046
11	**11**	November	35,754	441	140	900	5,679	951	17	43,882
12	**12**	December	36,013	443	145	902	5,704	950	17	44,174
13			428,824	5,325	1,658	10,882	68,040	11,566	211	526,506
14	**Distribution Revenues**		**2.0%**	**2.0%**	**-5.0%**	**-5.0%**	**-20.0%**	**-20.0%**	**-20.0%**	**<--- Scenario Input**
15		January	$2,325,805	$38,294	$815,328	$462,712	$435,134	$99,036	$1,936	$4,178,245
16		February	$1,966,811	$35,537	$809,086	$463,061	$410,502	$81,239	$1,719	$3,767,955
17		March	$1,869,856	$31,739	$793,776	$471,760	$393,234	$74,307	$1,527	$3,636,199
18		April	$1,840,861	$29,928	$797,630	$457,249	$383,406	$65,546	$1,454	$3,576,074
19		May	$1,662,389	$24,858	$825,066	$477,521	$357,698	$49,931	$1,216	$3,398,679
20		June	$1,830,426	$24,015	$908,458	$489,597	$379,765	$44,645	$1,241	$3,678,147
21		July	$2,083,927	$27,147	$963,600	$512,648	$404,434	$46,950	$1,526	$4,040,232
22		August	$2,284,420	$30,205	$1,013,171	$524,031	$437,669	$50,738	$1,777	$4,342,011
23		September	$2,063,945	$28,413	$957,876	$485,660	$403,483	$44,958	$1,215	$3,985,550
24		October	$1,686,623	$23,306	$868,201	$478,499	$354,676	$43,131	$1,163	$3,455,599
25		November	$1,723,838	$25,316	$810,053	$450,304	$346,263	$55,468	$1,084	$3,412,326
26		December	$2,076,784	$32,329	$866,038	$458,637	$411,222	$77,223	$1,551	$3,923,784
27			23,415,685	351,087	10,428,283	5,731,679	4,717,486	733,172	17,409	45,394,801
28	**Hypothetical Actual Revenue Per Customer (Actual RPC)**									
29	**1**	January	$65.15	$86.64	$6,039.47	$511.85	$77.03	$100.95	$107.56	
30	**2**	February	$55.33	$79.86	$5,993.23	$511.10	$72.49	$83.32	$95.50	
31	**3**	March	$52.38	$71.32	$6,013.45	$518.42	$69.34	$76.21	$84.83	
32	**4**	April	$51.59	$66.95	$6,088.78	$507.49	$67.41	$67.78	$80.78	
33	**5**	May	$46.61	$55.99	$5,851.53	$522.45	$63.31	$51.58	$67.56	
34	**6**	June	$51.39	$54.21	$6,583.03	$542.19	$67.36	$46.17	$68.94	
35	**7**	July	$58.56	$60.73	$6,932.37	$556.02	$71.07	$48.86	$84.78	
36	**8**	August	$60.91	$67.88	$7,085.11	$556.30	$74.16	$49.07	$93.53	
37	**9**	September	$60.42	$64.72	$6,941.13	$556.95	$74.37	$51.03	$81.00	
38	**10**	October	$46.98	$52.49	$6,157.45	$528.14	$62.44	$45.12	$68.41	
39	**11**	November	$48.21	$57.41	$5,786.09	$500.34	$60.97	$58.33	$63.76	
40	**12**	December	$57.67	$72.98	$5,972.68	$508.47	$72.09	$81.29	$91.24	

Line No.										
42	**Hypothetical Decoupling Calculation**		**Domestic**	**Domestic - Opt. Peak**	**General TOU**	**General Long Hour**	**General Service**	**Limited All Electric**	**Ltd Comm Space Heating**	**Total**
43			**DOD2**	**D10**	**G01**	**G02**	**G03**	**T00**	**V00**	
44	**January**	Target RPC	$64.51	$85.71	$6,357.33	$538.79	$96.29	$126.19	$134.44	
45		Hypo. Act. RPC	$65.15	$86.64	$6,039.47	$511.85	$77.03	$100.95	$107.56	
46		Difference	$0.6396	$0.92	($317.87)	($26.94)	($19.26)	($25.24)	($26.89)	
48		Hypo. Act. Bills	35,697	442	135	904	5,649	981	18	
50	1	**Decoupling Adjustment**	**$22,830**	**$408**	**($42,912)**	**($24,353)**	**($108,784)**	**($24,759)**	**($484)**	**($178,054)**
51										Refund / (Charge) to Customers

Line No.	Monthly Journal Entry		
55	Account	Dr.	Cr.
56	Deferred Debit - Decoupling	$178,054	
57	Revenues		($178,054)
59	Purpose:	To accrue monthly decoupling adjustment for future refund or collection on customers' bills at the conclusion of the decoupling year.	

Liberty Utilities, NH
Granite State Electric
Hypothetical Decoupling Annual Calculation

	A	B	C	D	E	F	G	H	I	J
	Hypothetical Decoupling Calculation		**Domestic**	**Domestic - Opt. Peak**	**General TOU**	**General Long Hour**	**General Service**	**Limited All Electric**	**Ltd Comm Space Heating**	**Total**
Line No.			**DOD2**	**D10**	**G01**	**G02**	**G03**	**T00**	**V00**	
1	**January**	Target RPC	$64.51	$85.71	$6,357.33	$538.79	$96.29	$126.19	$134.44	
2	**1**	Hypothetical Actual RPC	$65.15	$86.64	$6,039.47	$511.85	$77.03	$100.95	$107.56	
3		Difference	$0.6396	$0.92	($317.87)	($26.94)	($19.26)	($25.24)	($26.89)	
4		Hypothetical Actual Bills	35,697	442	135	904	5,649	981	18	
5		**Decoupling Adjustment**	**$22,830**	**$408**	**($42,912)**	**($24,353)**	**($108,784)**	**($24,759)**	**($484)**	**($178,054)**
6	**February**	Target RPC	$54.79	$79.00	$6,308.66	$538.01	$90.61	$104.15	$119.39	
7	**2**	Hypothetical Actual RPC	$55.33	$79.86	$5,993.23	$511.10	$72.49	$83.32	$95.50	
8		Difference	$0.5424	$0.86	($315.43)	($26.90)	($18.12)	($20.83)	($23.89)	
9		Hypothetical Actual Bills	35,545	445	135	906	5,663	975	18	
10		**Decoupling Adjustment**	**$19,279**	**$381**	**($42,583)**	**($24,372)**	**($102,625)**	**($20,310)**	**($430)**	**($170,660)**
11	**March**	Target RPC	$51.86	$70.56	$6,329.95	$545.70	$86.68	$95.27	$106.06	
12	**3**	Hypothetical Actual RPC	$52.38	$71.32	$6,013.45	$518.42	$69.34	$76.21	$84.83	
13		Difference	$0.5142	$0.76	($316.50)	($27.28)	($17.34)	($19.05)	($21.22)	
14		Hypothetical Actual Bills	35,700	445	132	910	5,671	975	18	
15		**Decoupling Adjustment**	**$18,356**	**$340**	**($41,778)**	**($24,829)**	**($98,309)**	**($18,577)**	**($382)**	**($165,179)**
16	**April**	Target RPC	$51.08	$66.23	$6,409.24	$534.20	$84.26	$84.73	$101.00	
17	**4**	Hypothetical Actual RPC	$51.59	$66.95	$6,088.78	$507.49	$67.41	$67.78	$80.78	
18		Difference	$0.5062	$0.72	($320.46)	($26.71)	($16.85)	($16.95)	($20.22)	
19		Hypothetical Actual Bills	35,682	447	131	901	5,688	967	18	
20		**Decoupling Adjustment**	**$18,062**	**$322**	**($41,980)**	**($24,066)**	**($95,851)**	**($16,387)**	**($364)**	**($160,264)**
21	**May**	Target RPC	$46.15	$55.39	$6,159.50	$549.95	$79.14	$64.48	$84.44	
22	**5**	Hypothetical Actual RPC	$46.61	$55.99	$5,851.53	$522.45	$63.31	$51.58	$67.56	
23		Difference	$0.4571	$0.60	($307.97)	($27.50)	($15.83)	($12.90)	($16.89)	
24		Hypothetical Actual Bills	35,666	444	141	914	5,650	968	18	
25		**Decoupling Adjustment**	**$16,304**	**$265**	**($43,424)**	**($25,133)**	**($89,424)**	**($12,483)**	**($304)**	**($154,199)**
26	**June**	Target RPC	$50.89	$53.63	$6,929.51	$570.73	$84.20	$57.71	$86.17	
27	**6**	Hypothetical Actual RPC	$51.39	$54.21	$6,583.03	$542.19	$67.36	$46.17	$68.94	
28		Difference	$0.5033	$0.58	($346.48)	($28.54)	($16.84)	($11.54)	($17.22)	
29		Hypothetical Actual Bills	35,616	443	138	903	5,638	967	18	
30		**Decoupling Adjustment**	**$17,927**	**$256**	**($47,814)**	**($25,768)**	**($94,941)**	**($11,161)**	**($310)**	**($161,811)**
31	**July**	Target RPC	$57.99	$60.08	$7,297.24	$585.28	$88.83	$61.07	$105.94	
32	**7**	Hypothetical Actual RPC	$58.56	$60.73	$6,932.37	$556.02	$71.07	$48.86	$84.78	
33		Difference	$0.5747	$0.65	($364.86)	($29.26)	($17.77)	($12.21)	($21.17)	
34		Hypothetical Actual Bills	35,584	447	139	922	5,691	961	18	
35		**Decoupling Adjustment**	**$20,449**	**$292**	**($50,716)**	**($26,981)**	**($101,109)**	**($11,737)**	**($381)**	**($170,183)**
36	**August**	Target RPC	$60.31	$67.15	$7,458.01	$585.58	$92.70	$61.34	$116.89	
37	**8**	Hypothetical Actual RPC	$60.91	$67.88	$7,085.11	$556.30	$74.16	$49.07	$93.53	
38		Difference	$0.5977	$0.73	($372.90)	($29.28)	($18.54)	($12.27)	($23.37)	
39		Hypothetical Actual Bills	37,505	445	143	942	5,902	1,034	19	
40		**Decoupling Adjustment**	**$22,417**	**$323**	**($53,325)**	**($27,581)**	**($109,417)**	**($12,684)**	**($444)**	**($180,711)**
41	**September**	Target RPC	$59.83	$64.04	$7,306.45	$586.26	$92.97	$63.79	$101.27	
42	**9**	Hypothetical Actual RPC	$60.42	$64.72	$6,941.13	$556.95	$74.37	$51.03	$81.00	
43		Difference	$0.5928	$0.69	($365.32)	($29.31)	($18.59)	($12.76)	($20.27)	
44		Hypothetical Actual Bills	34,160	439	138	872	5,425	881	15	
45		**Decoupling Adjustment**	**$20,248**	**$301**	**($50,414)**	**($25,561)**	**($100,871)**	**($11,239)**	**($304)**	**($167,840)**
46	**October**	Target RPC	$46.52	$51.93	$6,481.53	$555.94	$78.05	$56.40	$85.53	
47	**10**	Hypothetical Actual RPC	$46.98	$52.49	$6,157.45	$528.14	$62.44	$45.12	$68.41	
48		Difference	$0.4612	$0.56	($324.08)	($27.80)	($15.61)	($11.28)	($17.12)	
49		Hypothetical Actual Bills	35,902	444	141	906	5,680	956	17	
50		**Decoupling Adjustment**	**$16,557**	**$249**	**($45,695)**	**($25,184)**	**($88,669)**	**($10,783)**	**($291)**	**($153,816)**
51	**November**	Target RPC	$47.74	$56.80	$6,090.62	$526.67	$76.22	$72.91	$79.71	
52	**11**	Hypothetical Actual RPC	$48.21	$57.41	$5,786.09	$500.34	$60.97	$58.33	$63.76	
53		Difference	$0.4727	$0.61	($304.53)	($26.33)	($15.24)	($14.58)	($15.94)	
54		Hypothetical Actual Bills	35,754	441	140	900	5,679	951	17	
55		**Decoupling Adjustment**	**$16,901**	**$269**	**($42,634)**	**($23,700)**	**($86,566)**	**($13,867)**	**($271)**	**($149,868)**
56	**December**	Target RPC	$57.10	$72.20	$6,287.03	$535.23	$90.12	$101.61	$114.06	
57	**12**	Hypothetical Actual RPC	$57.67	$72.98	$5,972.68	$508.47	$72.09	$81.29	$91.24	
58		Difference	$0.5647	$0.78	($314.35)	($26.76)	($18.02)	($20.32)	($22.82)	
59		Hypothetical Actual Bills	36,013	443	145	902	5,704	950	17	
60		**Decoupling Adjustment**	**$20,335**	**$345**	**($45,581)**	**($24,139)**	**($102,806)**	**($19,306)**	**($388)**	**($171,540)**
61									**Annual Total**	**($1,984,125)**

Annual Deferral Calculation

A	B	C	D	E	F	G	H	I	J
		A + B		C / D			(E - F) or (E - G)	D * H	C - I
Current Year Adjustment	Prior Years' Deferral Balance	Total Adjustment	Total Company Target Revenues	Percent of Total	"Soft" Cap		Amount in excess of Cap %	Amount in excess of Cap $	Annual Allowed Adjustment
$ (1,984,125)	$ -	$ (1,984,125)	$ 47,146,327	-4.21%	-3.00%	3.00%	-1.21%	$ (569,735)	$ (1,414,390)
								Deferral of excess to next year's calculation	Refund / (Charge) to Customers

Rate Class Allocation	DOD2	D10	G01	G02	G03	T00	V00	Total
Class % of Total Distribution Revenues	48.69%	0.73%	23.28%	12.80%	12.51%	1.94%	0.05%	100.00%
Decoupling Adjustment	**$ (688,697)**	**$ (10,326)**	**$ (329,314)**	**$ (181,000)**	**$ (176,906)**	**$ (27,494)**	**$ (653)**	**$ (1,414,390)**

Bill Impacts for Purposes of Sensitivity Example Only*	DOD2	D10	G01	G02	G03	T00	V00	Total
kWh	278,824,882	5,629,249	379,184,992	147,993,116	88,095,304	15,352,073	328,389	915,408,005
$/kWh	$ 0.00247	$ 0.00183	$ 0.00087	$ 0.00122	$ 0.00201	$ 0.00179	$ 0.00199	$ 0.00155
Monthly Use Per Customer (kWh)	650	1,057	228,700	13,600	1,295	1,327	1,556	
Monthly Impact	**$ 1.61**	**$ 1.94**	**$ 198.62**	**$ 16.63**	**$ 2.60**	**$ 2.38**	**$ 3.09**	

* Actual rate impact calculations will take into account both kWh and kW.

LIBERTY UTILITIES (GRANITE STATE ELECTRIC) CORP. d/b/a LIBERTY UTILITIES

ELECTRICITY DELIVERY SERVICE TARIFF - NHPUC NO. 21

SUPERSEDING

ELECTRICITY DELIVERY SERVICE TARIFF NHPUC NO.19

AND IN LIEU OF NHPUC NO. 20

Applicable

in

Various towns and cities in New Hampshire,

served in whole or in part.

(For detailed description, see Service Area)

NHPUC NO. 21 - ELECTRICITY DELIVERY

TERMS AND CONDITIONS FOR DELIVERY SERVICE

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TERMS AND CONDITIONS FOR DELIVERY SERVICE

1. Service Area

The territory authorized to be served by this Company and to which this Tariff applies is as follows:

Acworth*
Alstead*
Atkinson*
Bath*
Canaan*
Charlestown*
Cornish*
Derry*
Enfield*
Grafton*
Hanover*
Langdon*
Lebanon
Lyme*
Marlow*
Monroe*
Orange*
Pelham*
Plainfield*
Salem
Surry*
Walpole
Windham*

* Served in part.

The above enumerates the towns served but does not mean that service is available throughout the entire area of each town specified.

Limited areas of the towns so identified above are as shown on the maps filed separately with the Commission and incorporated in this tariff by reference.

2. Definitions

The following words and terms shall have the following meanings when used in this Tariff, including in any agreements entered into under this Tariff:

Application: A request by a Customer for Delivery Service pursuant to the provisions of this Tariff.

Commission: The New Hampshire Public Utilities Commission.

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

Customer: Any person, firm, corporation, cooperative marketing association, utility or government unit or sub-division of a municipality or of the state or nation supplied with Delivery Service by the Company. Each Delivery Service account shall be considered a separate and distinct Customer.

Energy Service ("Energy Service"): Electric energy, ancillary services and capacity supplied to a Customer who is not receiving Energy Service from a Competitive Electric Power Supplier or receiving Self Supply Service. Energy Service shall be provided in accordance with Energy Service Tariff and shall be provided in conjunction with the applicable Delivery Service Rate Schedule.

Delivery Service: The delivery of electric power by the Company to a Customer under this Tariff.

Electronic Enrollment: A request submitted electronically to the Company by a Supplier for the initiation of Supplier Service to a Customer.

FERC: The Federal Energy Regulatory Commission.

Force Majeure: Any cause beyond the reasonable control of, and without the fault or negligence of, the Party claiming Force Majeure. It shall include, without limitation, sabotage, strikes or other labor difficulties, soil conditions, riots or civil disturbance, acts of God, acts of public enemy, drought, earthquake, flood, explosion, fire, lightning, landslide, sun storms or similarly cataclysmic occurrence, or appropriation or diversion of electricity by sale or order of any governmental authority having jurisdiction thereof. Economic hardship of either Party shall not constitute a Force Majeure under this Tariff.

Local Network: The distribution facilities which are owned, leased and maintained by the Company, which are located in the state of New Hampshire and that are used to provide Delivery Service under this Tariff.

Month: Whenever reference is made to electricity delivered or a payment to be made "in any month", "each month" or "per month", it shall mean the electricity delivered in the period between two successive regular monthly meter readings or the payment to be made in respect of such period.

Parties or Party: Liberty Utilities and/or one or more Customers under this Tariff.

Payment Agent: Any third-party authorized by a Customer to receive and pay the bills rendered by the Company for service under this Tariff.

Rate Schedule: The Rate Schedules included as part of this Tariff.

Specifications for Electrical Installations booklet: The booklet prepared by the Company to establish standardized rules and regulations for the installation of electric service connections within the Company's Service Area. The booklet is available online here https://new-hampshire.libertyutilities.com/uploads/2019%20Version%203.0_ESB750%20Specifications%20for%20Electrical%20Installations.pdf

Self-Supply Service: Electric energy, ancillary services and capacity purchased by a Customer directly from the New England wholesale electric market managed by ISO-NE.

Tariff: This Delivery Service Tariff and all Rate Schedules, appendices and exhibits to such Tariff.

3. General

The Company undertakes to render dependable Delivery Service in accordance with this Tariff, of which these Terms and Conditions are a part, as on file from time to time with the Commission and legally in effect; such undertaking being subject to the applicable rules and regulations of the Commission and to the Company's Specifications for Electrical Installations booklet.

Although the Company will endeavor to make the service rendered as continuous and uninterrupted as it reasonably can, Delivery Service is subject to variations in its characteristics and/or interruptions to its continuity. Therefore, the characteristics of the Delivery Service may be varied and/or such service to any Customer or Customers may be interrupted, curtailed, or suspended in the following described circumstances; and the obligations of the Company to render service under this Tariff are subject to such variance, interruption, curtailment, or suspension:

i. When necessary to prevent injury to persons or damage to property.
ii. When necessary to permit the Company to make repairs to or changes and improvements in a part or parts of the Company's electrical facilities; such action to be taken upon reasonable notice to the Customers to be affected, if practicable, or without any notice in an emergency when such notification would be impracticable or would prolong a dangerous situation.
iii. When conditions in a part or parts of the interconnected generation-transmission system of which the Company's facilities are a part make it appear necessary for the common good.

iv. When such variance, including a reversal of supply, or such interruption, curtailment or suspension is a result of Force Majeure as defined in this Tariff and any cause except willful default or neglect on the Company's part.

The Company shall not be responsible for any loss, cost, damage or expense to persons and/or property resulting therefrom.

The Company does not undertake to regulate the voltage or frequency of its service more closely than is standard commercial practice or required by the rules of the Commission. If the Customer requires regulation of voltage or frequency that is more refined, the Customer shall furnish, install, maintain and operate the necessary apparatus at the Customer's expense.

4. Availability

Delivery Service shall be available to a Customer who has made an Application and has satisfied all of the requirements of this Tariff. Delivery Service shall be available solely for the delivery of electricity from a Supplier to a Customer or for the delivery of Energy Service or Self-Supply Service to a Customer.

In the event that a Customer is not receiving Self-Supply Service and is not receiving Supplier Service from a Supplier for any reason, the Company will arrange Energy Service provided the Customer has satisfied all the requirements for service under this Tariff.

5. Application, Contract and Commencement of Service

Application by the Customer for Delivery Service may be made to the Company at any time. Whether or not an Application for service is made by the Customer and accepted by the Company, the rendering of the service by the Company and its use by the Customer shall be deemed a contract between the parties and subject to all provisions of the Tariff, as in effect from time to time, applicable to the service.

Except as otherwise specifically provided for under a Rate Schedule, all rates are predicated on a period of service at one location of not less than twelve (12) consecutive months, with monthly billing and monthly payment. The rendering of bills to Customers under this Tariff shall be performed exclusively by the Company.

6. Deposits, Payments, Refusal or Discontinuance of Service

The Company, to protect against loss, may require a satisfactory cash deposit or other guarantee as a condition of new or continuing service. No deposit shall be less than ten (10) dollars nor more than the estimated charge for utility service for a period of two (2) high-use billings periods, exclusive of the highest-use billing period, and calculated pursuant to New Hampshire Administrative Rules Puc 1203.03(l)(1). The Customer shall have the opportunity to pay the deposit in three (3) equal monthly installments, with the first payment due immediately, the second payment due within thirty (30) days and the final payment due within sixty (60) days, provided that the first payment shall be for no more than the charge for one month's utility service calculated as provided in Puc 1203(l)(1)(b); and the second and third payments shall be in equal installments of the remainder due.

All deposits shall accrue simple annual interest from the date of deposit to the date of termination of service by the customer. Interest shall accrue at a rate equal to the prime rate. When a deposit has been held longer than 12 months, interest shall be paid to the customer or credited to the customer's current bill not less than annually. The entire deposit plus interest accrued shall be refunded when all bills have been paid without arrearage for 12 consecutive months for a residential customer and 24 consecutive months for a non-residential customer. With the agreement of the customer, deposits plus the interest accrued thereon may be applied against the current bills until the balance of the deposit is exhausted. Upon termination of service, the deposit plus interest accrued less any amount due the utility shall be refunded within 60 days of the date of termination.

Charges for service under rates in this Tariff are predicated upon monthly billing, which as far as practicable will be thirty (30) days apart, and will be due upon presentation of bill. The Company may discontinue service for non-payment after a bill, or a portion thereof, becomes thirty (30) days overdue, or for other good cause, in accordance with applicable statutes and the rules and regulations of the Commission in effect at the time. Service to the Customer may be discontinued at the location where the Company furnished the service for which the overdue bill was rendered; or, if service is no longer being furnished to the Customer at that location, the Company may discontinue service at the current location, if the debt is uncontested and accrued within the past three years, subject to the Commission's Rules and Regulations.

When service has been disconnected for nonpayment, the Company may make a reasonable charge for reconnection before service is restored.

Except as otherwise specifically provided in any agreement between the Company and the Customer, charges for service furnished under this Tariff shall continue until such time as the Company shall receive reasonable notice from the Customer of a desire to terminate the service. The date of termination shall be the date specified by the Customer but not sooner than four business days from the date the Customer notified the Company.

The Company may require an applicant, as a condition of new service, to enter into a reasonable repayment plan for an uncontested debt owed to the Company within the past three years.

Uncontested debt shall include any amounts for services provided by the Company for any amounts for Delivery Service and any Energy Service furnished to the applicant.

Whenever a Customer makes payment to the Company for service under this Tariff with a check or draft that is not accepted by the institution on which it is written, the Company shall make a charge to the Customer of either $15.00 or the actual administrative cost of recovery, whichever amount is greater.

7. Failure of Payment Agent to Remit Payment

A Customer who has elected to use a Payment Agent shall be treated in the same manner as other Customers in the Company's application of the applicable statutes, rules and regulations of the Commission and the terms and conditions of this Tariff, notwithstanding any failure of the Payment Agent to remit payment to the Company or any failure of the Payment Agent to forward to the Customer any Company notices, bill inserts or other written correspondence. The Customer shall be solely responsible for all amounts due, including, but not limited to, any late payment charges.

8. Refusal to Serve

The Company reserves the right to refuse to supply Delivery Service to new Customers or to supply additional load to any existing Customer if it is unable to do so under a Rate Schedule or if it is unable to obtain the necessary equipment and facilities or capital required for the furnishing of such service. The Company may refuse to supply Delivery Service to load of unusual characteristics which might affect the cost or quality of service supplied to other Customers of the Company. The Company may require a Customer having such unusual load to install special regulating and protective equipment in accordance with the Company's specifications as a condition of service.

9. Service Connection and Reconnection Charges

A service connection fee shall be charged to all customers requesting new service.

Service Connection Charge - No Field Visit Required	$20.00
Service Connection Charge – Field Visit Required	$35.00

The Company shall have the right to discontinue its service on due notice and to remove its property from the premises in case the Customer fails to pay any bill due the Company for such service, or fails to perform any of its obligations to the Company. For restoration of service after such discontinuance, all customers shall be charged a reconnection fee.

Service Reconnection Charge	$35.00

A fee to establish or reestablish service outside of normal working hours which requires the Company to send an employee to the meter location shall be charged.

Establish or Reestablish Service Outside of Normal Business Hours Charge	$70.00

A fee may be assessed when it is necessary to send an employee to the Customer location to collect a delinquent bill. This charge shall apply regardless of any action taken by the Company including accepting a payment, making a deferred payment arrangement or leaving a collection notice at the Customer's premises.

Delinquent Bill Collection Charge	$35.00

10. Determination of the Demand

The "Maximum Demand" or "Customer's Load," which shall be stated in kilowatts or kilovolt-amperes as specified in the applicable Rate Schedules G-1 and G-2, is defined as the greatest rate of taking Delivery Service during the specified interval on pages 96 and 99, respectively.

Where a Rate Schedule requires determination of maximum demand, it shall be determined by measurement or estimated as provided by the Rate Schedule or, where applicable, by the provisions of the following paragraph of this section. The Company shall not be obligated, for any reason, to use the demand values measured or estimated by any other entity in the determination of maximum demand.

When the nature of the Customer's load is of an intermittent, instantaneous or widely fluctuating character such as to render demand meter readings of doubtful value as compared to the actual capacity requirements, the demand may be determined on the basis of a time interval less than that specified, or on the basis of the minimum transformer capacity necessary to render the Delivery Service, or the minimum protective device rating necessary to permit continuous uninterrupted service. In all such instances, the Company will record the basis of demand determination.

11. Fluctuating Load Policy

In certain instances, extremely fluctuating loads or harmonic distortions which are created by customer's machinery may cause a deterioration of the Company's service to its other customers. Since service for such loads may require new facilities or the rearrangement of existing facilities, the Company will approve the connection of such apparatus to the Company's facilities only after it has determined that the apparatus meets the Specifications for Electrical Installations booklet. If the Company furnishes a separate service connection to such load, then a separate bill for such service will be rendered. Charges for billing for electricity supplied will be as provided in the rate plus an amount equal to $2.76 per month per KVA of transformer needed.

If the Company does not furnish a separate connection for such load but does install additional transformer capacity, other new facilities, or rearranges its existing facilities, the customer may be required to make a payment or other guarantees such as an agreement by the customer to pay a minimum amount each month in lieu of, or in addition to, an up-front payment. Any such agreement would be based on the specific circumstances of the customer, and would be contained in a special contract filed with the Commission.

12. Underground Service

Prior to January 1, 2019, a Customer's premises may be connected to the Company's aerial distribution wires through an underground connection where the Customer installs, owns and maintains all of the underground service including the necessary riser. All underground service connected to the Company's underground distribution cables beyond two feet inside the property line shall be installed by the Customer and shall be and remain the property of the Customer.

For installations after January 1, 2019, a Customer's premises may be connected to the Company's aerial distribution wires through an underground connection as provided for in Policies 1 through 4.

13. Rate for Trial Installations

The Company may, provided it has spare generating and transmission capacity, supply electricity for trial purposes at other than its regular rates. The period for the trial must be no longer than is necessary for the demonstration and must be specified in the agreement. Any such rates would be determined on a case-by-case basis, and would be included in a special contract filed with the Commission.

14. Installation and Sealing of Meter Switches and Circuit Breakers

The Customer shall furnish and install upon its premises such service conductors, service equipment, including oil circuit breaker if used, and meter mounting device as shall conform with specifications issued from time to time by the Company, and the Company may seal such service equipment and meter mounting device, and adjust, set and seal such oil circuit breaker and such seals shall not be broken and such adjustments or settings shall not be changed or in any way interfered with by the Customer. In the event that a seal needs to be removed for access, only the Company or licensed electrician are authorized with notification to the Company prior to the removal of the seal.

15. Customer's Responsibility for Installation of Equipment on Its Premises

The Customer shall furnish, at no cost to the Company, the necessary space, housing, fencing and foundations for such equipment as will be installed upon its premises, in order to supply it with electricity, whether such equipment be furnished by the Customer or the Company. Such space, housing, fencing and foundations shall be in conformity with the Company's specifications and subject to its approval. Further information regarding the Company's specifications is contained within the Specifications for Electrical Installations booklet, which may be found here: https://new-hampshire.libertyutilities.com/uploads/2019%20Version%203.0_ESB750%20Specifications%20for%20Electrical%20Installations.pdf

16. Services to Barns or Garages

The Company shall not be required to install a service or meter for a garage, barn or other out-building, so located that it may be supplied with electricity through a service and meter in the main building.

17. Point of Connection of Company's Service

The Company shall furnish on request detailed information on the method and manner of making service connections. Such detailed information may include a copy of the Company's Specifications for Electrical Installations booklet, as may be amended from time to time, a description of the service available, connections necessary between the Company's facilities and the Customer's premises, location and access of service connection facilities and metering equipment, and Customer and Company responsibilities for installation of facilities.

The Customer shall wire to the point designated by the Company, at which point the Company will connect its service.

For a service meeting Company requirements, the Company may also permit this connection to be made by a licensed electrician in good standing with the authority having jurisdiction, as required by applicable law, and who is registered with the Company, provided, however, that the Company gives no warranty to the Customer, express or implied, as to the knowledge, training, reliability, honesty, fitness, or performance of any electrician registered with the Company for this purpose, and the Company shall not be liable for any damages or injuries caused by any electrician who may be used for such purpose.

18. Obtaining Street or Other Permits and Certificates

The Company shall make, or cause to be made, application for any necessary street permits, and shall not be required to supply service until a reasonable time after such permits are granted. The Customer shall obtain or cause to be obtained all permits or certificates, except street permits, necessary to give the Company or its agent's access to the Customer's equipment and to enable its conductors to be connected therewith.

19. Meters

The Company will provide each Customer with proper metering equipment subject to the ability of the Company to obtain the same.

The Company shall own and maintain the metering equipment necessary to measure Delivery Service under this Tariff. Each meter location shall be designated by the Company and the Company shall have priority over any other entity with respect to placement of Company-owned metering equipment.

Any Customer requesting non-standard metering equipment, the cost of which exceeds the cost of the metering equipment necessary for the rendering of Delivery Service under the applicable Rate Schedule, shall be responsible for the additional cost of the requested metering equipment including any incremental labor costs associated with installation of the requested metering equipment. Any such metering equipment must be approved by the Company.

Where an individual household or business enterprise, occupation or institution occupies more than one unit of space, each unit will be metered separately and considered a distinct Customer, unless the Customer furnishes, owns and maintains the necessary distribution circuits by which to connect the different units to permit delivery and metering at one location of all the energy used.

The Company may for its own convenience install more than one meter per Customer, but in such cases the meter readings will be cumulated when billing.

In cases of non-access or where a meter fails to register the full amount of electricity consumed, the amount of the bill will be estimated by the Company, based upon the use recorded during previous months, or upon the best information available. The Company may estimate, rather than meter, demand and kilowatt-hours used by a Customer where the demand and kilowatt-hour usage are constant and known or for locations which, in the Company's judgment, are unsafe or impractical to separately meter or to access on a regular basis by Company personnel.

20. Meter Testing and Customer Bill Adjustments

When requested by a customer, the Company shall test the accuracy of the Customer's meter within fifteen days from the date the request is made. The Company may require a deposit fee for such a test. If, upon testing, the meter is found to be in error by more than two (2) percent, the deposit shall be refunded. If the meter is not found to be in error by as much as two (2) percent, the Company shall retain the deposit for the test.

Delinquent Bill Collection Charge $20.00

Whenever, as the result of a test, a watt-hour meter is found to register in excess of two (2) percent of the correct amount, the Company shall refund the Customer an amount equal to the charge for the excess kilowatt-hours billed for a period equal to one half the time elapsed since the last previous test. However, if the time when the error first developed or occurred can be definitely fixed, the amount to be refunded shall be based thereon. Whenever, as the result of a test, a watt-hour meter is found to have a negative average error in excess of two (2) percent, the Company may charge the Customer for the unbilled kilowatt-hours supplied for the previous six (6) months or since the last test, whichever is the shorter period.

If a meter is found which is not registering, or if it is found that a meter has partially registered the electricity delivered to the Customer, the bill for the period of non-registration or partial registration shall be based upon information recorded prior or subsequent to the period of non-registration or partial registration. The Company shall not charge the difference between the billed and estimated amounts for a period greater than six (6) months before the non-registration or partial registration was discovered unless the Customer was diverting electricity. In cases of diversion, the Company shall charge the Customer the difference between the billed and estimated amounts for the entire period of the diversion.

21. Customer's Use of Electricity

In recognition of the fact that the wiring and facilities for the use of electricity on the Customer's premises are owned by and under the control of the Customer, the Company shall not be responsible for any loss, cost, damage, or expense to persons and/or property resulting from the use of or presence in the Customer's wiring or appliances, electricity delivered in accordance with the provisions of these Terms and Conditions and the Company's Specification for Electrical Installations booklet.

If the Customer's requirements for electricity or use of service, or installation of Customer-owned equipment (including but not limited to motors, generation, meters, or capacitors) results in or is anticipated to result in damage to the Company's apparatus or facilities or electrical disturbances to other customers on the Company's distribution system, the Customer shall be responsible for the cost to the Company of repairing, replacing or upgrading the Company's facilities. If the Customer fails to correct for the interference with the operation of the Company's distribution system or with the electrical supply to other Customers, the Company reserves the right to refuse service or to disconnect service upon proper notice.

22. Required Standards of Customer's Wiring, Piping, Apparatus, and Equipment

The Customer's wiring, piping, apparatus and equipment shall, at all times, conform to the requirements of any legally constituted authorities and to those of the Company, and the Customer shall keep such wiring, piping, apparatus and equipment in proper repair. Further information regarding the Company's specifications is contained within the Specifications for Electrical Installations booklet, which may be found here: https://new-hampshire.libertyutilities.com/uploads/2019%20Version%203.0_ESB750%20Specifications%20for%20Electrical%20Installations.pdf

23. Compliance

Service hereunder is subject to the Customer's compliance with the following conditions:

i. The Customer shall comply with or perform all of the requirements or obligations of this Tariff and the Company's Specifications for Electrical Installations booklet.

ii. The Customer shall allow the Company reasonable access to the Company's facilities located on the Customer's premises.

iii. The Customer shall comply with any applicable orders and regulations of the Commission.

iv. The Customer shall not cause or allow to exist any unauthorized or fraudulent use or procurement of the Delivery Service or any tampering with the connections or other equipment of the Company, or any condition on the Customer's premises involving the Delivery Service which is dangerous to health, safety or the electric service of others or which represents a clear and present danger to life, health, or physical property, or to the Company's ability to serve its other Customers.

v. The Customer shall notify the Company when the Customer no longer desires Delivery Service.

24. Resale of Delivery Service

No Customer shall sell, resell, assign or otherwise dispose of all or any part of the Delivery Service purchased from the Company without the written consent of the Company. The sale of electric vehicle charging services electricity to a third party from an electric vehicle charging station shall not be considered resale of electricity.

25. Company Property

The Company shall have the right to install, maintain and operate such Company-owned facilities on the premises of the Customer as in its judgment may be required to render Delivery Service to the Customer in accordance with this Tariff, as such facilities shall be overhead or underground and whether the premises of the Customer are owned or leased to the Customer, and shall have the free right at all reasonable times to enter upon said premises for the purpose of maintaining, repairing, replacing or removing such facilities. Normally such facilities will consist of, but they shall not be limited to, overhead or underground service wires or cables extending to a Company-owned meter or meters and associated equipment.

Customer must provide, without expense or cost to the Company, the necessary permits, consents or easements satisfactory to the Company in order to install, maintain, repair, replace, or remove the Company's facilities on the Customer's property or property owned by others on which facilities are placed to serve the Customer.

If the Customer is a tenant or a mortgagor and his right of occupancy does not include authority to grant the Company the foregoing rights, he shall obtain his landlord's or his mortgagee's authority to grant the foregoing rights, and the Company may require that such authority be evidenced in writing by the landlord or mortgagee.

26. Relocation of Equipment on Private Property

Lines, poles and transformer stations on private property are usually situated in locations that were the result of negotiations and mutual agreement with the property owner. When the equipment is Company-owned and is used to supply more than one customer, permanent easements or other rights of way satisfactory to the Company should be obtained.

27. Relocation of Company-Owned Equipment

Subsequent changes in the location of Company-owned facilities on private property will in general be made by the Company at the Customer's expense. Line Extension Policy 3 – Individual C&I Customer provides direction for the calculation of the Customer's expense associated with relocation of Company-owned equipment.

The Company, however, will assume the expense of the relocation if the following conditions exist:

a) The relocation is for the Company's convenience, or
b) The relocation is necessary owing to the expansion of the Customer's operations and the expense is justified by the increased annual revenue.

The preceding should not be construed to apply to a situation where the existing location is adequate to handle the expanded operations or where the relocation is requested solely for the Customer's convenience. In any such instance the relocation will be at the Customer's expense even though increased revenue will result from the expanded operations.

28. Relocation of Customer-Owned Equipment

All Customer-owned equipment on private property shall under any circumstances be relocated by the Customer or its Contractor at the expense of the Customer.

29. Customer Street Crossings

i. Customer Owned

In the event a Customer desires to supply electricity for its own use at a location situated on the opposite side of a public way by installing conductors under the street, the Customer should petition for the conductor crossing from the local governmental board having jurisdiction. Upon securing the necessary permits, the Customer will construct the crossing in accordance with current National Electric Safety Code and by applicable rules and regulations of the local government board having jurisdiction to a location designated by the Company. The Customer will own, operate and maintain the crossing.

ii. Company-Owned

Should the Customer be unable to obtain the necessary permits or should the crossing entail attachments to Company-owned facilities or require the setting of poles in the public way, the Company, upon request, will petition for the wire crossing, subject to the following conditions:

1. Construction - The Customer shall reimburse the Company for the entire construction cost of the crossing. Title to that portion of the crossing in the public way shall remain with the Company.

2. Maintenance - All maintenance to that portion in the public way will be done by the Company at the expense of the Customer. In order to facilitate proper billing, a purchase order should be secured prior to any maintenance work.

3. Removal of Street Crossing - Upon notice from the Customer that the crossing is no longer desired, the Company will remove the crossing at the Customer's expense. Any salvage value will be credited to the cost of removing the crossing; and in the event the credit exceeds the removal cost, the excess shall be refunded to the Customer.

4. Street Crossing Agreement - All street crossings for Customers made by the Company under above conditions must be covered by a street crossing agreement.

For underground line extension installations after January 1, 2019, this policy no longer applies.

30. Holidays

The following New Hampshire legal holidays shall be recognized as holidays for purposes of billing service in off-peak periods:

Holiday	**Day Celebrated**
*New Year's Day	January 1st
Martin Luther King, Jr. / Civil Rights Day	Third Monday in January
Presidents Day	Third Monday in February
Memorial Day	Last Monday in May
*Independence Day	July 4th
Labor Day	First Monday in September
Columbus Day	Second Monday in October
*Veterans Day	November 11th
Thanksgiving Day	When appointed
*Christmas	December 25th

* If these days fall on Sunday, the following day shall be considered the holiday.

31. Conjunctional Service

Conjunctional Service is a Customer's use of Delivery Service under this Tariff for delivery of either Supplier Service or Energy Service which supplements or is in addition to any other source of electric service connected on the Customer's side of the meter. Conjunctional Service must be taken in accordance with the Company's Specifications for Electrical Installations booklet and the Company's technical guidelines and requirements pertaining to Qualifying Facilities ("QFs", as defined in Sections 201 and 210 of Title II of the Public Utility Regulatory Policies Act of 1978) filed with the Commission in compliance with Commission Order No. 14,797. Conjunctional service is available to QFs and to other Customers who are not QFs who have available another source of electric service connected on the Customer's side of the meter.

All Conjunctional Service furnished by the Company to Customers under this Tariff shall be taken by the Customers under the Rate Schedule which would otherwise be available for Delivery Service applicable to the total internal load of the Customer.

32. Customer Choice of Rate

Upon a Customer’s request, the Company shall provide information as to what may be the most advantageous rates and charges available to the Customer under this Tariff. However, the responsibility for the selection of a rate lies with the Customer and the Company does not warrant or represent in any way that a Customer will save money by taking service under a particular rate. The Company will not be liable for any claim that service provided to a Customer might have been less expensive or more advantageous to such Customer if supplied under another available rate.

33. Statement by Agent

No representative of the Company has the authority to modify any rule, provision or rates contained in this Tariff, or bind the Company for any promise or representation contrary thereto.

34. Third Party Claims and Non-Negligent Performance

Each Party agrees to indemnify and hold the other Party and its affiliated companies and the trustees, directors, officers, employees, and agents of each of them (collectively "Affiliates") harmless from and against any and all damages, costs (including attorneys' fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively "Liabilities") resulting from claims of third parties arising, or claimed to have arisen, from the acts or omissions of such Party in connection with this Tariff. Each Party hereby waives recourse against the other Party and its Affiliates for, and releases the other Party and its Affiliates from, any and all Liabilities for or arising from damage to its property due to a non-negligent performance by such other Party.

35. Charges for Temporary Services

The Company will charge the Customer for the total cost incurred in constructing and removing temporary services at locations under construction where the temporary service will not be converted to a permanent service. Such costs shall include the costs of labor, overheads and all materials except for the costs of transformers and meters. The Company shall not charge for the construction and removal of such temporary service whenever the temporary service is to be replaced at approximately the same location with a permanent service when construction is completed, provided that the permanent service is run from the same pole and utilizes the same material which was utilized for the temporary service. The charges are only applicable to temporary services that are not made permanent.

36. Stranded Cost Charge

The Stranded Cost Charge will recover, on a fully reconciling basis, the costs incurred by the Company for costs associated with the Contract Termination Charge from New England Power Company to Granite State Electric Company including fixed and variable components made effective pursuant to the Settlements of New England Power Company's ("NEP") all-requirements contracts with Granite State Electric Company ("Granite State"). The charge will recover the annual reconciliation associated with the Contract Termination Charge. This charge shall be recovered by all customers taking delivery service.

The Settlements were approved by the Federal Energy Regulatory Commission ("FERC") in Docket Nos. ER98-2023-000 and (as amended) ER98-3925-000, and by the New Hampshire Public Utilities Commission in N.H.P.U.C. Docket No. DR 98-012 ("Settlement"). The Stranded Cost Charge is designed to reconcile costs and revenues under the Settlements for each calendar year. The Contract Termination Charge ("CTC") formula set forth in the Settlements provides for a reconciliation to be performed annually. Capitalized terms not otherwise defined are intended to have the same meaning set forth in the CTC formula.

NEP, Granite State and the New Hampshire Public Utilities Commission entered into an agreement ("USGenNE CTC Settlement") on December 5, 2005, related to issues surrounding the resolution of the USGenNE bankruptcy proceeding. The USGenNE CTC Settlement provided that Granite State's allocated share of the allowed claim proceeds received by NEP be used to pay down all of the remaining NEP power purchase contract buyout payments allocable to New Hampshire and to provide a residual value credit, with return, through the year 2010. The settlement also provided for updates to decommissioning expense and purchased power costs that are included in the base CTC. FERC approval was received on February 28, 2006.

In accordance with the Settlements, the estimated CTC related costs that are reconciled annually are primarily the costs comprising the Variable Component. These estimated costs are reconciled to actual costs through the Reconciliation Adjustment and accumulated in the Reconciliation Account. In addition, revenues collected through the CTC are reconciled to actual revenues based upon differences in megawatt hour ("MWh") deliveries.

The Stranded Cost Charge shall be established annually based on a forecast of includable costs, and shall also include a full reconciliation with interest for any over recovery or under recovery occurring in the prior year. The Company may file to change the Stranded Cost Charge rates at any time if a significant over recovery or under recovery occurs. Interest on over recoveries or under recoveries shall be calculated at the prime rate.

Any changes to rates determined under the Stranded Cost Charge shall only be made following a notice filed with the Commission setting forth the amount of the increase or decrease, the new rates for each rate class, and the effective date of such new rates.

37. Reliability Enhancement Program and Vegetation Management Plan Adjustment

All energy billed under this rate is subject to a Reliability Enhancement Program and Vegetation Management Plan Adjustment Factor which shall be adjusted from time to time pursuant to the Settlement Agreement in Docket DE 19-064.

38. Reliability Enhancement Program Capital Investment Allowance

Distribution base rates are subject to adjustment on an annual basis for a Reliability Enhancement Program Capital Investment Allowance pursuant to the Settlement Agreement in Docket DE 19-064.

39. Transmission Charge

The Transmission Charge will recover, on a fully reconciling basis, the costs incurred by the Company for transmission related services, and other reconciling charges as noted below. These costs include charges billed to the Company by Other Transmission Providers; third party charges billed to the Company for transmission related services such as charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges; and transmission-based assessments or fees billed by or through regulatory agencies, including those associated with the ISO-NE, regional transmission group, an independent system operator, an RTO and their successors, or other such body with the oversight of regional transmission, in the event that any of these entities are authorized to bill the Company directly for their services.

The Transmission Charge shall be established annually based on a forecast of includable costs, and shall also include a full reconciliation with interest for any over recovery or under recovery occurring in the prior year. The Company may file to change the rates at any time if a significant over recovery or under recovery occurs. Interest on over recoveries or under recoveries shall be calculated at the prime rate.

Any changes to rates determined under the charge shall only be made following a notice filed with the Commission setting forth the amount of the increase or decrease, the new rates for each rate class, and the effective date of such new rates.

The Transmission Charge includes the Regional Greenhouse Gas Initiative ("RGGI") refund as required by RSA 125-O:23,II and Order No. 25,664 dated May 9, 2014, which directs the Company to refund RGGI auction revenue it receives to its customers.

40. Electricity Consumption Tax Charge

All Customers shall be obligated to pay the Electricity Consumption Tax Charge in accordance with New Hampshire Statute RSA Chapter 83-E, which may be revised from time to time, in addition to all other applicable rates and charges under this Tariff. The Electricity Consumption Tax Charge shall appear separately on all Customer bills. Any discounts provided for under a Special Contract shall not apply to the Electricity Consumption Tax Charge.

41. System Benefits Charge

All customers taking delivery service shall pay the System Benefits Charge as required by New Hampshire law and approved by the Commission. The System Benefits Charge shall recover the cost of the Company's (i) Electric Assistance Program and (ii) energy efficiency core programs and any other such energy efficiency programs, as approved by the Commission.

The Company shall implement its Electric Assistance Program as approved by the Commission from time to time. The System Benefits Charge will fund the Company's Electric Assistance Program and such other system benefits as are required by law or approved by the Commission.

The Company will reconcile on an annual basis actual costs incurred of the Electric Assistance Program, including development, implementation, and ongoing administrative and maintenance costs against the actual amounts charged to customers through the portion of the System Benefits Charge attributable to the Electric Assistance Program, set at a level of 0.150¢ per kilowatt-hour in accordance with RSA 374-F:4, VIII (c), and shall be in addition to the portion of the System Benefits Charge relating to the Company's energy efficiency core programs stated below.

The Company shall implement its energy efficiency core programs as approved by the Commission from time to time. The Company's cost of implementing the energy efficiency core programs shall be recovered through the portion of the System Benefits Charge attributable to such programs, set at a level of 0.528¢ per kilowatt-hour in accordance with Order No. 26,323 in Docket No. DE 17-136 Electric and Gas Utilities 2018-2020 New Hampshire Statewide Energy Efficiency Plan, which shall be in addition to the portion of the System Benefits Charge relating to the Company's low income customer protection programs stated above. Any difference between the actual energy efficiency funds expended and the funds collected through the System Benefits Charge at 0.528¢ per kilowatt-hour during a calendar year shall, with interest calculated at the average prime rate for each month, be added to or subtracted from the amount to be expended in the following calendar year. If actual amounts are not available for any period, they shall be estimated for purposed of the above calculations and adjusted the following year based on actual data.

Any adjustment of the System Benefits Charge shall be in accordance with a notice filed with the Commission setting forth the amount of the increase or decrease, and the new System Benefits Charge amount. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Commission may authorize.

System Benefits Charge

Electric Assistance Program (EAP)	0.150¢
Energy Efficiency Programs	0.528¢
Lost Revenue Mechanism	0.000¢
Total System Benefit Charge	0.678¢

42. Late Payment Charge

The rates and charges billed under this Tariff are net, billed monthly and payable upon presentation of the bill. However, Customers who receive Delivery Service under Residential Rate D, Residential Time-of-Day Rate D-10, OR General Service Rate G-3, may elect to pay for all service rendered under these rates, as well as Energy Service Rate ES, on a Levelized Payment Plan available upon application to the Company.

For Customers rendered Delivery Service under General Service Rate G-3, General Long Hour Service Rate G-2 or General Service Time-of-Use Rate G-1, all amounts previously billed but remaining unpaid after the due date printed on the bill shall be subject to a late payment charge of one and one-half percent (1 ½ %) thereof, such amounts to include any prior unpaid late payment charges.

The late payment charge is not applicable to Customers taking service under Rate D and Rate D-10, or past due balances of General Service Rate G-3 or Outdoor Lighting Rate M Customers who are abiding by the terms of an extended payment arrangement agreed to by the Company.

43. Provisions for Billing Charges Associated with Meter Diversions and Damage to Company Equipment in Connection Therewith

In case of loss or damage to the Company's property on a Customer's premises the Customer shall pay to the Company the value of the property or the cost of making good the loss or damage.

In those cases where, as a result of or in connection with diversion of electricity supplied by the Company to the Customer's premises, whether such diversion is carried out by bypassing the meter or other measuring device or by other means, the Company incurs expense for labor and/or materials, the Customer responsible therefore will be charged the costs incurred by the Company for such labor and materials. The costs so chargeable may include, but are not limited to, the cost of investigating the diversion and the miscellaneous charges for service associated therewith, the cost of supplying and installing an exchange meter, the cost of furnishing and installing tamper-resistant devices, the cost of testing the meter associated with the diversion and the cost of replacement of a meter which has been damaged.

Bills for charges associated with meter diversions will be rendered as soon as possible after completion of the work.

44. Electric Assistance Program

Customers served under Rate Schedules D, D-10 and T of Granite State Electric Company ("the Company") may be eligible to receive discounts pursuant to the Company's Electric Assistance Program. Customers participating in the Electric Assistance Program will continue to take service pursuant to their respective Rate Schedules, but will receive a percent discount off of the total amount billed for the first 750 kWh consumed per month, exclusive of the Electricity Consumption Tax and the Water Heater Rental fee, under such Rate Schedules. Discounts provided under the Electric Assistance Program are identified below and shall be funded by the System Benefits Charge in accordance with the System Benefits Charge Provision included on Page 22 of this tariff.

Effective: May 13, 2016

Tier	Percentage of Federal Poverty Guidelines	Disount
1	Not Applicable	Not Applicable
2	151-200	8%
3	126-150	22%
4	101-125	36%
5	76-100	52%
6	0-75	76%

Eligibility criteria and benefit levels shall be based upon Federal Poverty Guidelines and are stated above for each tier. Community Action Agencies of New Hampshire shall be responsible for certifying customer qualification in the Electric Assistance Program and shall notify the Company of a customer's enrollment into the Electric Assistance Program and the applicable tier that would determine the discount that the Company should apply.

Effective April 27, 2014, the income eligibility for participation in the Electric Assistance Program is at or below 200% of the Federal Poverty Guidelines.
The availability of the Electric Assistance Program shall be subject to approval by the Public Commission.

45. Energy Service Adjustment Provision

Energy Service shall be procured by the Company pursuant to a competitive bidding process, and the rates for Energy Service shall be based on short-term market prices and include an estimate of administrative costs associated with the provision of Energy Service.

On an annual basis, the Company shall perform two reconciliations for Energy Service. In the first reconciliation, the Company shall reconcile its power supply cost of providing Energy Service with its Energy Service revenue associated with the recovery of power supply costs, and the excess or deficiency, including interest at the interest rate paid on customer deposits, shall be returned to, or recovered from, all Energy Service customers over the following 12 months through the Energy Service Adjustment Factor. In the second reconciliation, the Company shall reconcile its administrative cost of providing Energy Service with its Energy Service revenue associated with the recovery of administrative costs, and the excess or deficiency, including interest at the interest rate paid on customer deposits, shall be reflected in the subsequent year's Energy Service Cost Reclassification Adjustment Factor pursuant to the Energy Service Cost Reclassification Adjustment Provision. The Company may file to change the Energy Service Adjustment Factor at any time should significant over- or under- recoveries of Energy Service costs occur. For purposes of this reconciliation, Energy Service revenue shall mean all revenue collected from Energy Service customers through the Energy Service rate for the applicable 12 month reconciliation period together with payments or credits from suppliers for the provision of Energy Service. The power supply cost of providing Energy Service shall mean all payments to suppliers and the Independent System Operator associated with the provision of Energy Service.

Administrative costs of providing Energy Service shall mean all labor and consultant costs in arranging and administering Energy Service, any payments related to the cost of providing contract security, Energy Service-related working capital cost, and Energy Service-related bad debt cost.

Any adjustment to the Energy Service Adjustment Factor under the Company's applicable rates shall be in accordance with a notice filed with the Commission setting forth the amount of the increase or decrease and the new Energy Service Adjustment Factor. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Commission may authorize.

This provision is applicable to all Retail Delivery Service rates of the Company.

46. Storm Recovery Adjustment Provision

The Company's rates for Retail Delivery Service are subject to adjustment to reflect increased or decreased funding to the Company's Storm Fund ("Storm Fund") through a Storm Recovery Adjustment Factor. The Company shall implement a factor designed to provide the increased or decreased funding to the Storm Fund at an amount approved by the Commission through the funding period.

The Storm Recovery Adjustment shall be a uniform cents per kilowatt-hour factor applicable to all kilowatt-hours delivered by the Company to customers taking retail delivery service under each of the Company's rates. The factor shall be based on the estimated kilowatt-hours defined as the forecasted amount of electricity, as measured in kilowatt-hours, to be delivered by the Company to its retail delivery service customers over the funding period approved by the Commission over which the factor is to be applied to customers' bills.
The Company shall file with the Commission the results of its funding as part of its annual storm fund report.

Any adjustment of the Storm Recovery Adjustment Factor shall be in accordance with a notice filed with the Commission setting forth the amount of the increase or decrease, and the new Storm Recovery Adjustment amount. The notice shall further specify the effective date of such adjustment, which shall not be earlier than thirty days after the filing of the notice, or such other date as the Commission may authorize.

47. Energy Service

Energy Service shall be available under this Tariff to all Customers, including Customers that return to Company-provided energy supply service after receiving energy service from a Competitive Supplier or self-supply.

i. Character of Service

Electricity will be supplied with the same characteristics as specified in the applicable Delivery Service Tariffs.

ii. Energy Service Charge

For the purposes of this Tariff, the customer groups are defined as:

Customer Group	**Rate Class**
Small Customer Group	D, D-10, G-3, M, LED-1, LED-2, T and V

Large Customer Group G-1 and G-2

iii. Small Customer Group Energy Service Charges

Rate Effective February 1, 2020 – July 31, 2020 per kWh 7.193¢

iv. Large Customer Group Energy Service Charges

	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020
Rate ¢/kWh	9.749¢	7.777¢	6.715¢	5.868¢	5.246¢	5.790¢

v. Switching to a Competitive Supplier or Self-Supply

1. On Next Meter Read Date

The Company will normally switch a Customer to a Competitive Supplier or self-supply upon request of a Customer as of the next Tariffed meter read, provided that notice of the change to a Competitive Supplier or self-supply was received by the Company not less than two business days before that next Tariffed meter read date. There shall be no charge for switching from Energy Service to a Competitive Supplier or self-supply if such a notice is given.

2. Prior to the Next Tariffed Meter Read Date

If switching to a Competitive Supplier or self-supply before the next Tariffed meter read is requested, the Company at its sole discretion and upon agreement by the Customer to pay the applicable fee pursuant to the Off Cycle Meter Read Provision of this Tariff will terminate Energy Service with an un-tariffed meter read.

48. Optional Enhanced Metering Service Provision

Optional Enhanced Metering Service under this provision is available to a Customer receiving metered retail delivery service from the Company. Customers who currently receive unmetered retail delivery service must request metered retail delivery service from the company in accordance with the Company's terms and conditions. The availability of these services will be subject to the Company's ability to render such service.

The Company shall provide two types of service under Optional Enhanced Metering Service. These are: Service Option 1, Complete Service, and Service Option 2, Pulse Service.

i. Service Option 1 – Complete Service

Under this service option, Complete Service, the Company will provide equipment at the Customer's facility that will allow for periodic readings of the Customer's load through telephone lines. The Company will install, own and maintain the equipment in service. The Customer or Supplier may receive the data through the optical port on the equipment or electronically. The Company will store load information on the meter for a period of 35 days and will read the meters daily.

The one-time fee for this service is as follows for Retail Delivery Service:

1. Rate schedules D, D-10, and T	$155.31
2. Rate schedules G-1, G-2, G-3, M, and V	$247.08

ii. Service Option 2 – Pulse Service

A Customer who wishes to connect their own metering equipment to the Company's meter may elect this option. The Company will provide a pulse interface device through which the Customer can access meter data. The Customer must purchase, own and maintain a device or system which would connect to the pulse interface device in order to access meter pulses.

The one-time fee for this service is as follows for Retail Delivery Service:

1. Rate schedules D, D-10, and T	$135.31
2. Rate schedules G-1, G-2, G-3, M and V	$122.07

The Company's terms and conditions in effect from time to time where not inconsistent with any specific provisions hereof, are a part of this Optional Enhanced Metering Service Provision.

49. Optional Interval Data Service Provision

Optional Interval Data Service under this provision is available to a Customer receiving service from the Company under the Company's Optional Enhanced Metering Service Provision, or a Customer receiving metered retail delivery service from the Company who has a Company-owned interval data recorder ("IDR") installed at their facility.

Under Optional Interval Data Service, the fees will vary depending upon the number of accounts and frequency of requests for interval data. Access is available to the Customer or its authorized agent.

i. One-Time Request for Interval Data

1.	Initial request within a single calendar year	No Charge
2.	Subsequent request within the same calendar year single account	$55.00
3.	Additional delivery service account request per account	$23.00

ii. Subscription Service for Interval Data over the Internet

The Company may offer subscriptions to eligible Customers for access to interval data through an Internet account that is available for the Customer or Supplier's use. The minimum contract length is one year. The availability of this service will be subject to the Company's ability to render such service.

1.	Single delivery service account, annually	$309.00
2.	Additional delivery service account request per account, annually	$277.00

iii. Optional Billing and Rate Data Service Provision

Optional Billing and Rate Data Service is available under this provision for a Customer receiving retail delivery service from the Company under any of the rate schedules contained in the Company's retail delivery service tariff.

Any request for Billing and Rate Data Service may be made either by the Customer having the customer of record's authorization to receive data to be released by the Company under Billing and Rate Data Service.

iv. Services Provided – One per Calendar Year with No Fee

1. Usage and Billing kW Data

For Commercial and Industrial Customers, the Company will provide the Customer of record name, rate class, service address, and 13 months of peak and off-peak kW, kWh, and KVA data.

For Residential Customers, the Company will provide the Customer of record name, rate class, service address, and 13 months of total kWh data.

2. Rate Data

Rate summaries and rate schedules included in the Company's tariff are available on the Liberty Utilities website for all other rate schedules. Customers or Suppliers requesting hard copies of summaries or rate schedules will be provided with that information free of charge.

iv. Custom Service or Additional Data Provided for a Fee

The Company shall provide Customer Load Analysis to Suppliers. The Supplier is responsible for obtaining the Customer's authorization to release this information and will be required to maintain confidentiality of the Customer information. The Supplier may not sell or provide this information, in whole or in part, to another party.

1. Custom Reports Charge	$49.00 per hour
2. Rate Data Charge	$49.00 per hour
3. Rate Analysis Charge	$49.00 per hour

50. Off Cycle Meter Read for Switch of Supplier Provision

An Off Cycle Meter Read under this provision is available to customers receiving metered retail delivery service from the Company under the Company's Rate G-1, General Service Time-of-Use rate. The availability of this service will be subject to the Company's ability to render such service.

A Customer requesting an Off Cycle Meter Read agrees to pay the Off Cycle Meter Read Charge included in this provision.

An Off Cycle Meter Read will be performed by the Company at the request of the Customer to facilitate the transfer of energy service between the Company-supplied Energy Service and Competitive Supplier energy service. There will be a separate Off Cycle Meter Read Charge for a Customer who is telemetered and for a Customer who is non-telemetered. The Company will assess an Off Cycle Meter Read Charge for each off cycle meter read performed at a Customer's service location.

1. Telemetered Customer Off Cycle Read Charge	$78.00
2. Non-Telemetered Customer Off Cycle Read Charge	$102.00

The Company's terms and conditions in effect from time to time where not inconsistent with any specific provisions hereof, are a part of this Off Cycle Meter Read for Switch of Supplier

51. Purchases from Qualifying Facilities

i. Availability

The Company will purchase electric energy from any small power producer, cogenerator, or limited electric energy producer (collectively referred to as a qualifying facility, or QF) in its service territory (i) under the Limited Electrical Energy Producers Act (LEEPA, NH RSA Chapter 362-A) or (ii) under Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA, 16 U.S.C. 824a-3) that meet the criteria specified by the Federal Energy Regulatory Commission (FERC) in 18 C.F.R. §§292.203 (a) and (b). Such purchases will be in excess of the facility's requirements. QFs not utilizing Net Energy Metering or selling their output to a purchaser or purchasers other than the Company shall have their electric energy output metered and purchased by the Company and then resold into the Real-Time Energy Market administered by ISO New England Inc. ("ISO-NE"). The Company reserves the right to require the QF to pay any administrative or service fees as may be assessed by the Company.

The Company shall not purchase for resale any capacity or other reserve-related products associated with the QF. The Company will not purchase or own any of the generation attributes associated with the QF.

ii. Metering

QFs selling to the Company shall install metering as specified by the Company that either satisfy (i) ISO-NE requirements or (ii) Net Energy Metering requirements, as both may change from time to time. QFs shall be charged a standard monthly service fee for metering service as approved by the appropriate regulatory agency.

iii. Indemnification

QF shall defend, indemnify and hold the Company harmless from and against all claims for damage to the equipment of the QF, or Company, as the case may be, or damage or injury to any person or property arising out of the QF's use of generating equipment in parallel with the Company's own system; provided that nothing in this paragraph shall relieve the Company from liability for damages or injury caused by its own willful default or willful neglect.

iv. Net Metering

Projects 100 kilowatts and under using renewable generation shall have the option of being served under the Net Energy Billing Service as specified by NH RSA 362-A:9 and the rules promulgated by the appropriate regulatory agency, and/or pursuant to the applicable alternative net energy metering tariff described in vi or vii below.

QFs with a peak generating capacity of 1,000 kW and under may choose to utilize Net Metering as specified in NH RSA 362-A:9 and in PART Puc 900 Net Metering For Customer-Owned Renewable Energy Generation Resources of 1,000 Kilowatts or Less, and/or pursuant to the applicable alternative net energy metering tariff described in vi or vii below.

v. Purchase Options:

QFs not utilizing Net Energy Metering or selling their output to a purchaser or purchasers other than the Company shall have their electric energy output metered and purchased by the Company and then resold into the Real-Time Energy Market administered by ISO New England Inc. ("ISO-NE"). Compensation for such purchases will be equal to the payments received by the Company from ISO-NE less all charges imposed by ISO-NE for such sales. The Company reserves the right to require the QF to pay any administrative or service fees as may be assessed by the Company.

The Company shall not purchase for resale any capacity or other reserve-related products associated with the QF. The Company will not purchase or own any of the generation attributes associated with the QF.

1. Qualifying Facilities (QFs) Utilizing Net Energy Metering with an Existing Allocation as Defined in Docket No. DE 15-271 Prior to March 2, 2017

Customers will be billed and receive credit for their generation in accordance with Puc 903.02(f) and Puc 903.02(g).

2. Qualifying Facilities (QFs) Utilizing Net Energy Metering with an Existing Allocation as Defined in Docket No. DE 15-271 Prior to March 2, 2017

Customers are required to have metering in accordance with Puc 903.02(c).

vi. Net Energy Metering Alternative Tariff Effective March 2, 2017 through August 31, 2017 ("2017 Interim Alternative Tariff")

1. Qualifying Facilities (QFs) Utilizing Net Energy Metering with an Allocation as Defined in Docket No. DE 15-271 Determined Beginning on March 2, 2017

Customers will be billed and receive credit for their generation in accordance with Puc 903.02(f) and Puc 903.02(g).

2. Qualifying Facilities (QFs) Utilizing Net Energy Metering with an Allocation as Defined in Docket No. DE 15-271 Determined Beginning on March 2, 2017

Customers are required to have metering in accordance with Puc 903.02(c).

3. Terms and Conditions
   a) The 2017 Interim Alternative Tariff is in effect on an interim basis beginning on March 2, 2017 and ending on August 31, 2017 (the Interim Period);
   b) The 2017 Interim Alternative Tariff continues the same terms and conditions of the existing standard tariffs, consistent with RSA 362-A:9 and the Puc 900 rules, subject to the further provisions described in paragraphs 3 and 4 below;
   c) The 2017 Interim Alternative Tariff provides that any eligible customer-generator whose qualifying project falls under the interconnecting utility's allocated share of the 100 megawatt cap set forth in RSA 362-A:9, I, and receives a net metering capacity allocation from the interconnecting utility during the Interim Period, would be subject to the terms and conditions of the 2017 Interim Alternative Tariff until December 31, 2040, notwithstanding any subsequent revision, modification, adoption, approval, revocation, or repeal of any applicable net metering tariff or other alternative regulatory mechanism applicable to eligible customer-generators; and
   d) The 2017 Interim Alternative Tariff provides that, if any utility reaches the applicable cap for net metering as set forth in RSA 362-A:9, I prior to or during the Interim Period, eligible customer-generators whose projects are above that cap would be able to continue to interconnect during the Interim Period subject to the 2017 Interim Alternative Tariff, except that such customer-generators will transition to the Alternative Net Metering Tariff described below as of September 1, 2017.

vii. Net Energy Metering Tariff Effective Beginning on September 1, 2017 in Accordance with Order No. 26,029 Dated June 23, 2017 ("Alternative Net Metering Tariff")

1. Eligibility

Customer-generators with installations of 100 kW (AC) or less are eligible to participate in net energy metering as a small customer-generator.

Customer-generators with installations of more than 100 kW (AC) are eligible to participate in net energy metering as a large customer-generator if they consume at least twenty percent (20%) of their installation's production on-site and behind-the-meter. If the on-site consumption of the customer-generator is less than 20% of the installation's production, the customer will have to be registered as a group host under RSA 362-A:9, XIV. Large customer-generators that meet the 20% on-site consumption threshold have the right to switch to the Alternative Net Metering Tariff by providing written notice of such election to the Company.

2. Metering

Each customer-generator will be required to have a bidirectional net meter installed and owned by the Company at no cost to the customer. Each customer-generator will have the option to have a production meter installed and owned by the Company at no cost to the customer.

3. Billing

Customer-generators with installations of 100 kW (AC) or less will be billed for the net electricity imported during each billing period under the same rate schedule that the customer would be billed if it had no generation, except that the Stranded Cost Charge, System Benefits Charge, Electricity Consumption Tax, and Storm Recovery Adjustment Factor will be billed on the full amount of electricity imported by the customer during each billing period.

Customer-generators with installations of 100 kW (AC) or less will be credited over subsequent billing periods for the net surplus electricity exported into the distribution system during each billing period for Energy Service, Transmission, and twenty-five percent (25%) of the Distribution rate under the same rate schedule. No credit will be applicable for the System Benefits Charge, Electricity Consumption Tax, and Storm Recovery Adjustment Factor.

Customer-generators with installations over 100 kW (AC) will be billed under the same rate schedule that the customer would be billed if it had no generation.

Customers with installations over 100 kW (AC) will be credited over subsequent billing periods for surplus electricity exported into the distribution system for Energy Service. No credit will be applied for any other retail delivery rates.

Small customer-generators will receive a monetary credit over subsequent billing periods for the net surplus electricity exported into the distribution system and will not accumulate surplus kWh following each applicable billing period. Large customer-generators will receive a monetary credit over subsequent billing periods for surplus electricity exported into the distribution system and will not accumulate surplus kWh following each applicable billing period.

For customer-generators taking energy service from a Competitive Supplier, the Competitive Supplier may determine the terms, conditions, and prices under which it agrees to provide generation supply to and purchase net generation output from the customer-generators. The Customer will not receive monetary credit over subsequent billing periods for net surplus electricity from the Company for supply. If net energy usage is less than zero, [small customer-generators] that do not receive Default Energy Service from the Company will receive a monetary bill credit for their net electric exports during each billing period calculated at twenty-five percent (25%) of any Distribution charges assessed on a per-kilowatt-hour basis; and any Transmission charges assessed on a per-kilowatt-hour basis.

Customer-generators with a monetary credit balance exceeding $100 as of March 31 of each year shall have the option to receive a cash payment for the monetary credit balance. Customer-generators with a monetary credit balance of any amount who move or discontinue service shall receive a cash payment for the full amount of their monetary credit balance.

4. Renewable Energy Certificates

The Company will serve as the independent monitor for customer-generators who elect to receive a Company-owned production meter. The Company will report the electricity production of such customer-generators at least quarterly to NEPOOL-GIS, at no cost to the customer. The Company will file an application on behalf of such customer-generators for Commission certification of the eligibility of their installations to produce renewable energy certificates pursuant to RSA 362-F and the Commission's Puc 2500 rules.

5. Applicable Period of Alternative Net Metering Tariff

Any customer-generator whose installation receives a net metering capacity allocation from the Company on or after September 1, 2017, and any customer-generator with an installation or capacity allocation above the Company's share of the net metering cap under RSA 362-A:9, I prior to or during the Interim Period, will be entitled to be net-metered pursuant to the Alternative Net Metering Tariff until December 31, 2040, notwithstanding any subsequent revision, modification, adoption, approval, revocation, or repeal of any applicable net metering tariff or other alternative regulatory mechanism applicable to customer-generators.

viii. Customers Taking Service Under Rate G-1 and Participating in Net Energy Metering Under the Standard Tariff or the 2017 Interim Alternative Tariff

For customer-generators participating in net energy metering under Puc 900 taking service under schedule Rate G-1, kWh exported during on-peak hours will be banked at the on-peak period, and kWh exported during off-peak hours will be banked at the off-peak period. In the months where the customer's banked kWh is applied to their bill, the kWh banked at the on-peak period will be applied to the amount charged for the on-peak period in that billing month, and the same method will be used for the off-peak period.

ix. Customers Taking Service Under Rate G-1 and Participating in Net Energy Metering Under the Alternative Net Metering Tariff

For customer-generators participating in net energy metering under the Alternative Net Metering Tariff and taking service under schedule Rate G-1, net surplus kWh exported during on-peak hours will be credited at the on-peak rate, and net surplus kWh exported during off-peak hours will be credited at the off-peak rate for subsequent billing periods.

x. Notification to the Company:

Any QF that plans to sell its electric output to the Company from a facility sized up to 100 kVA or 100 kW must comply with the Company's interconnection requirements as set forth in Granite State Interconnection Standards Provisions For Inverters Sized Up To 100 kVA as found in this Tariff.

For all other QFs, the Company must be notified in writing at least 120 days prior to interconnecting the QF with the Company's facilities. Such notification shall, at a minimum, include the following information:

a) The name, address and contact information of the applicant and location of the QF.
b) A brief description of the QF, including a statement indicating whether such facility is a small power production facility or a cogeneration facility.
c) The primary energy source used or to be used by the QF.
d) The power production capacity of the QF and the maximum net energy to be delivered to the utility's facilities at any clock hour.
e) The owners of the QF including the percentage of ownership by any electric utility or by any public utility holding company, or by any entity owned by either.
f) The expected date of installation and the anticipated on-line date.
g) The anticipated method of delivering power to the Company.
h) A description of any power conditioning equipment to be located between the QF and the Company's system.
i) A description of the type of generator used in the installation of the QF (synchronous, induction, photovoltaic, etc.).

Such notification shall be sent to:

Director of Engineering
Distribution Engineering Department
Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
9 Lowell Road
Salem, NH 03079

The Company will respond to the notification within 30 days and either request additional information regarding the QF or provide site specific interconnection requirements. The Company and the QF shall execute the standard purchase power agreement setting forth the terms of the sale, a form of which is attached in Schedule A of this tariff.

xi. Grandfathering Provisions

Subsequent sales or other transfers of ownership of a net-metered system or the property upon which the system is located shall be allowed to continue to take service under the same terms and conditions in effect at the time of such sale until 2040, in accordance with RSA 362-A:9,XV and Order No. 25,972, provided that the system is not moved to a different location by the purchaser, transferee, or otherwise.
Small customer-generators may expand their systems by an amount equal to the greater of either 20 kW or 50 percent of existing capacity, provided that in neither case can any such expansion have the effect of changing the system's eligibility from a small to a large customer-generator with capacity in excess of 100 kW.

Large customer-generators may expand their systems by an amount equal to or greater than (1) a system capacity increase of 50 kW, regardless of any on-site load changes, or (2) 110 percent of the customer-generator's annual load, as clearly demonstrated through the customer-generator's documentation of any consecutive 12-months within the previous two years.

In neither case can any such expansion have the effect of changing the system's eligibility from a large customer-generator to an ineligible system with capacity in excess of one megawatt. Expansion of a net-metered system by or for a commercial or industrial customer-generator smaller than the applicable limitation will continue to be grandfathered, while any such expansion in excess of the applicable limitation will result in the entire net-metered system losing its net metering grandfathered status.

Any system modifications must be reported to the Company within 30 days of modification.

Such notification shall be sent to:

Director of Engineering
Distribution Engineering Department
Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
9 Lowell Road
Salem, NH 03079

Schedule A

Qualifying Facility Purchase Power Agreement

The Agreement is between ______________, a Qualifying Facility ("QF") and Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (the "Company") for electric energy purchases by the Company from the QF's facility located in ____________, New Hampshire.

Agreement to Purchase

Effective _____________, the Company agrees to purchase electricity from the QF and the QF agrees to sell electricity to the Company under the terms and conditions of the Company's tariff for Energy Transactions with Qualifying Facilities as currently in effect or amended by the Company in the Company's sole discretion and as approved by the New Hampshire Public Utilities Commission. The QF agrees to comply with the terms and conditions of section 31 Purchases from Qualifying Facilities of this tariff and associated policies of the Company that are on file with the New Hampshire Public Utilities Commission as currently in effect or as modified, amended, or revised by the Company and to pay any metering and interconnection costs required under such tariff and policies.

Payments for Energy

QFs not utilizing Net Energy Metering shall have their electric energy output metered and purchased by the Company and then resold into the Real-Time Energy Market administered by ISO New England Inc. ("ISO-NE"). Compensation for such purchases will be equal to the payments received by the Company from ISO-NE less all charges imposed by ISO-NE for such sales. The Company reserves the right to require the QF to pay any administrative or service fees as may be assessed by the Company.

The Company shall not purchase for resale any capacity or other reserve-related products associated with the QF. The Company will not purchase or own any of the generation attributes associated with the QF.
Notice

The Company or QF may terminate this Agreement on thirty (30) days written notice which includes a statement of reasons for such termination.

Agreed and Accepted Date: ________

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

52. Interconnection Standards for Inverters Sized Up To 100 KVA

Any person or entity planning to operate a generating facility connected to the Company's facilities must receive approval from the Company prior to connecting the generating facility to the Company's facilities. A generating facility is any device producing electric energy which can range in size from a small residential photovoltaic solar installation to a large commercial generating facility. Inverter-based generating facilities sized up to 100 kVA must meet the standards of this Interconnections Standards Provision. For all other generating facilities, the Company must be contacted for site specific requirements prior to interconnecting the generating facilities with the Company's facilities.

i. Applicability

This document ("Interconnection Standard") describes the process and requirements for an Interconnecting Customer to connect a Listed inverter based Facility sized up to 100 kVA to the Company's Electric Power System ("Company EPS"), including discussion of technical and operating requirements, and other matters. Non-inverter based Facilities will need to follow the standard interconnection procedures.

If the Facility will always be isolated from the Company's EPS, (i.e., it will never operate in parallel to the Company's EPS), then this Interconnection Standard does not apply.

ii. Definitions

The following words and terms shall be understood to have the following meanings when used in this Interconnection Standard:

Affiliate: A person or entity controlling, controlled by or under common control with a Party.

Anti-Islanding: Describes the ability of a Facility to avoid unintentional islanding through some form of active control technique.

Application: The notice provided by the Interconnecting Customer to the Company in the form shown in Exhibit A, which initiates the interconnection process.

Area Network Distribution System: Electrical service from an EPS consisting of one or more primary circuits from one or more substations or transmission supply points arranged such that they collectively feed secondary circuits serving more than one Interconnecting Customer.

Commission: The New Hampshire Public Utilities Commission.

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

Customer: Company's retail customer; host site or premises, may be the same as Interconnecting Customer.

EPS: The electric power system owned, controlled or operated by the Company used to provide distribution service to its Customers.

Facility: A source of electricity that is located on the Customer's side of the point of common coupling, and all facilities ancillary and appurtenant thereto, including interconnection equipment, which the Interconnecting Customer requests to interconnect to the Company EPS.

In-Service Date: The date on which the Facility and System Modifications (if applicable) are complete and ready for service, even if the Facility is not placed in service on or by that date.

Interconnecting Customer: Entity that takes electric service from the Company who has or will obtain legal authority to enter into agreements regarding the interconnection of the Facility to the Company EPS.

Interconnection Service Agreement: An agreement for interconnection service, the form of which is provided in Exhibit A, between the Interconnecting Customer and the Company.

Islanding: A situation where electrical power remains in a portion of an electrical power system when the Company's transmission or distribution system has ceased providing power for whatever reason (emergency conditions, maintenance, etc.). Unintentional Islanding, especially past the PCC, is to be strictly avoided.

Isolated: The state of operating the Facility when electrically disconnected from the Company EPS on the Interconnecting Customer's side of the PCC.

Listed: A Facility that has been tested and certified by a nationally recognized testing laboratory to comply with all requirements in UL Standard 1741.1 dated May, 2007 or later.

Net Metering: A customer of the Company with a renewable on-site Facility of 100 kilovolt-amperes ("kVA") or less in size exercising the option to run the meter backward and thus choosing to receive a credit from the Company where in any month during which there was a positive net difference between kilowatt hours generated and consumed, the credit will equal the positive net difference. This credit is then used by the Customer in subsequent billing periods, until exhausted before purchasing energy from the Company.

Non-Islanding: Describes the ability of a Facility to avoid unintentional islanding through the operation of its interconnection equipment.

Parallel: The state of operating the Facility when electrically connected to the Company EPS (sometimes known as grid-parallel).

Parties: The Company and the Interconnecting Customer.

Point of Common Coupling (PCC): The point where the Interconnecting Customer's local electric power system connects to the Company EPS, such as the electric power revenue meter or premises service transformer. See the Company for the location at a particular Interconnecting Customer site.

Radial Distribution Circuit: Electrical service from an EPS consisting of one primary circuit extending from a single substation or transmission supply point arranged such that the primary circuit serves Interconnecting Customers in a particular local area.

Screen(s): Criteria by which the Company will determine if a proposed Facility's installation will adversely impact the Company EPS in the Simplified Processes as set forth in Section iv.

Simplified Process: As described in Section v., process steps from initial application to final written authorization for certain Listed inverter-based Facilities of limited scale and minimal apparent grid impact.

Spot Network Distribution System: Electrical service from an EPS consisting of one or more primary circuits from one or more substations or transmission supply points arranged such that they collectively feed secondary circuits serving only one Interconnecting Customer.

Supplemental Review: Additional engineering study to evaluate the potential impact of Facilities over 10 kVA on the Company EPS so as to determine any requirements for processing the application, or Facilities of 10 kVA or smaller that fail one of the Simplified Process screens. This review is charged based on the table provided below. If Company services are needed to install temporary metering to complete the Supplemental Review, then these charges will also be included as part of the overall review. Temporary metering charges are not defined in the tariff as each situation for interconnection has different service requirements. Thus, the charge for installation of temporary metering is determined on a case-by-case basis based on the actual cost of the particular installation.

Project Size (Max AC Rating of Inverters)	Supplemental Review Fee
>10 kW to 30 kW	$125
>30 kW to 50 kW	$500
>50 kW to 100 kW	$1000

Issued: XX XX, 20XX

Effective: XX XX, 20XX

Issued by: /s/ Susan L. Fleck
Susan L. Fleck

Title: President

Authorized by NHPUC Order No. ___ in Docket No. DE 19-064, dated ___

System Modification: Modifications or additions to distribution-related Company facilities that are integrated with the Company EPS for the benefit of the Interconnecting Customer and paid for by the Interconnecting Customer.
Unintentional Islanding: A situation where the electrical power from the Facility continues to supply a portion of the Company EPS past the PCC when the Company's transmission or distribution system has ceased providing power for whatever reason (emergency conditions, maintenance, etc.).

Witness Test: The Company's right to witness the commissioning testing. Commissioning testing is defined in IEEE Standard 1547-2003.

iii. Basic Understanding

Interconnecting Customer intends to install a Listed inverter based Facility on the Customer's side of the PCC that will be connected electrically to the Company EPS and operate in parallel, synchronized with the voltage and frequency maintained by the Company during all operating conditions. It is the responsibility of the Interconnecting Customer to design, procure, install, operate, and maintain all necessary equipment on its property for connection to the Company EPS. The Interconnecting Customer and the Company shall enter into a Simplified Process Application and Interconnection Service Agreement to provide for parallel operation of an Interconnecting Customer's Facility with Company EPS. A form of this agreement is attached as Exhibit A to this Interconnection Standard.

The equipment, controls and other facilities that together constitute the interconnection of the Facility with the Company EPS must be reviewed for potential impact on the Company EPS under the process described in Section iv.

The Interconnecting Customer should consult the Company before designing, purchasing and installing any generation equipment, in order to verify the nominal utilization voltages, frequency, and phase characteristics of the service to be supplied, the capacity available, and the suitability of the proposed equipment for operation at the intended location. Attempting to operate a Facility at other than its nameplate characteristics may result in unsatisfactory performance or, in certain instances, injury to personnel and/or damage to equipment. The Interconnecting Customer will be responsible for ascertaining from the Company, and the Company will cooperate in providing, the service characteristics of the Company EPS at the proposed PCC. The Company will in no way be responsible for damages sustained as a result of the Interconnecting Customer's failure to ascertain the service characteristics at the proposed PCC.

The Facility should operate in such a manner that does not compromise, or conflict with, the safety or reliability of the Company EPS. The Interconnecting Customer should design its equipment in such a manner that faults or other disturbances on the Company EPS do not cause damage to the Interconnecting Customer's equipment.

Authorization to interconnect will be provided once the Interconnecting Customer has met all terms of the interconnection process as outlined below.

This Interconnection Standard does not cover general distribution service needed to serve the Interconnecting Customer. Please refer to the Company's Terms and Conditions for Distribution Service. This Interconnection Standard does not cover the use of the distribution system to export power, or the purchase of excess power.

iv. Process Overview

This application process is for Listed inverter-based Facilities with a power rating of 100 kVA or less depending on the service configuration, and located on radial EPS under certain conditions. A Listed inverter-based Facility with a power rating of 10 kVA or less single-phase located on a spot network EPS under certain conditions would also be eligible.

Listed inverter based interconnections are intended to be reviewed promptly under a Simplified Process. A set of review screens have been developed to determine if the application fits the Simplified Process and are described below and detailed in Figures 1 and 2 with their accompanying notes. Table 1 describes the timelines for these paths. Unless otherwise noted, all times in the Interconnection Standard reference Company business days under normal work conditions.

A project that fails to meet the Simplified review screens will be addressed using the Company's standard interconnection review practices. In cases where the Facility is larger than 10 kVA, a Supplemental Review will be conducted. In addition a Supplemental Review may be required which may allow an interconnection of 10 kVA or smaller to be accommodated at a particular site even though it did not pass the Simplified review screens. In these instances, the Company will provide an estimated cost to do a Supplemental Review to the Interconnecting Customer. If the Interconnecting Customer funds the Supplemental Review, the Company will undertake the review to determine which of the following apply:

No system modifications are required and the simplified process can be used.

1. System modifications are required at the Customer's expense before the simplified process can be used. A statement will be sent to the Customer describing the required modification and a bill for the estimated amount.
2. The simplified process cannot be used and the Customer must reapply using the Company's standard interconnection process.

All proposed new sources of electric power that plan to operate in parallel with the Company EPS must submit a completed application to the Company within the Company's franchise territory where the Facility will be located. The Interconnecting Customer will be notified of the application's completeness. Interconnecting Customers proposing to interconnect on area networks require a detailed review of the planned interconnection and do not qualify for the Simplified Process. All applications from other Interconnecting Customers must proceed through a series of screens to determine if they meet the requirements for the Simplified Process interconnection path.

v. Simplified Process

Interconnecting Customers using Listed single-phase inverter-based Facilities with power ratings of 100 kVA or less at locations receiving single-phase service from a single-phase transformer, or using Listed three-phase inverter-based Facilities with power ratings of 100 kVA or less at locations receiving three-phase service from a three-phase transformer configuration, and requesting an interconnection on radial EPSs where the aggregate Facility capacity on the circuit is less than 7.5% of circuit annual peak load qualify for Simplified interconnection.

The Simplified Process is as follows:

1. Application process:

a) Interconnecting Customer submits a Simplified Process application filled out properly and completely (Exhibit A).
b) Interconnecting customer submits a non-professional engineer stamped electrical one-line diagram of the proposed system.
c) Company evaluates the application for completeness and notifies the Interconnecting Customer within 10 business days of receipt that the application is or is not complete and, if not, advises what is missing.
d) Company verifies Facility equipment passes screens 1, 2, and 3 in Figure 1 if a radial EPS, or the screens in Figure 2 if a spot network EPS.
e) If approved, the Company signs the application approval line and returns the approved application to the Interconnecting Customer. In certain circumstances, the Company may require the Interconnecting Customer to pay for System Modifications before the application is approved. If so, a description of work and an estimate of the cost will be sent back to the Interconnecting Customer for approval. The Interconnecting Customer would then approve via a signature and submit payment for any System Modifications. If the Interconnecting Customer approves, the Company performs the System Modifications. Then, the Company signs the application approval line and sends to the Interconnecting Customer.
f) Upon receipt of application signed by the Company, the Interconnecting Customer installs the Facility. Then the Interconnecting Customer arranges for inspection of the completed installation by the local electrical wiring

inspector, or other authority having jurisdiction, and this person signs the Certificate of Completion. If the Facility was installed by an electrical contractor, this person also fills out the Certificate of Completion.

f) The Interconnecting Customer returns Certificate of Completion to the Company.
g) Following receipt of the Certificate of Completion, the Company may inspect the Facility for compliance with standards by arranging for a Witness Test. The Interconnecting Customer has no right to operate in parallel until a Witness Test has been performed or has been previously waived by the Company on the Application Form. If the Company elects to conduct a Witness Test, every attempt will be made to conduct it within 10 business days of the receipt of the Certificate of Completion. All projects larger than 10 kVA will need to be witness tested, unless waived by the Company.
h) Assuming the wiring inspection and/or Witness Test is satisfactory, the Company notifies the Interconnecting Customer in writing that interconnection is authorized. If the Witness Test is not satisfactory, the Company has the right to disconnect the Facility, and will provide information to the Interconnecting Customer describing clearly what is required for approval.
i) If the Interconnecting Customer does not substantially complete construction within 12 months after receiving application approval from the Company, the Company will require the Interconnecting Customer to reapply for interconnection.

vi. Time Frames

1. Unless otherwise noted, all days in the Interconnection Standard reference Company business days under normal work conditions.
2. Table 1 lays out the maximum timeframes allowed under the Simplified Review process. The maximum time allowed for the Company to execute the entire Simplified Process is 20 days.

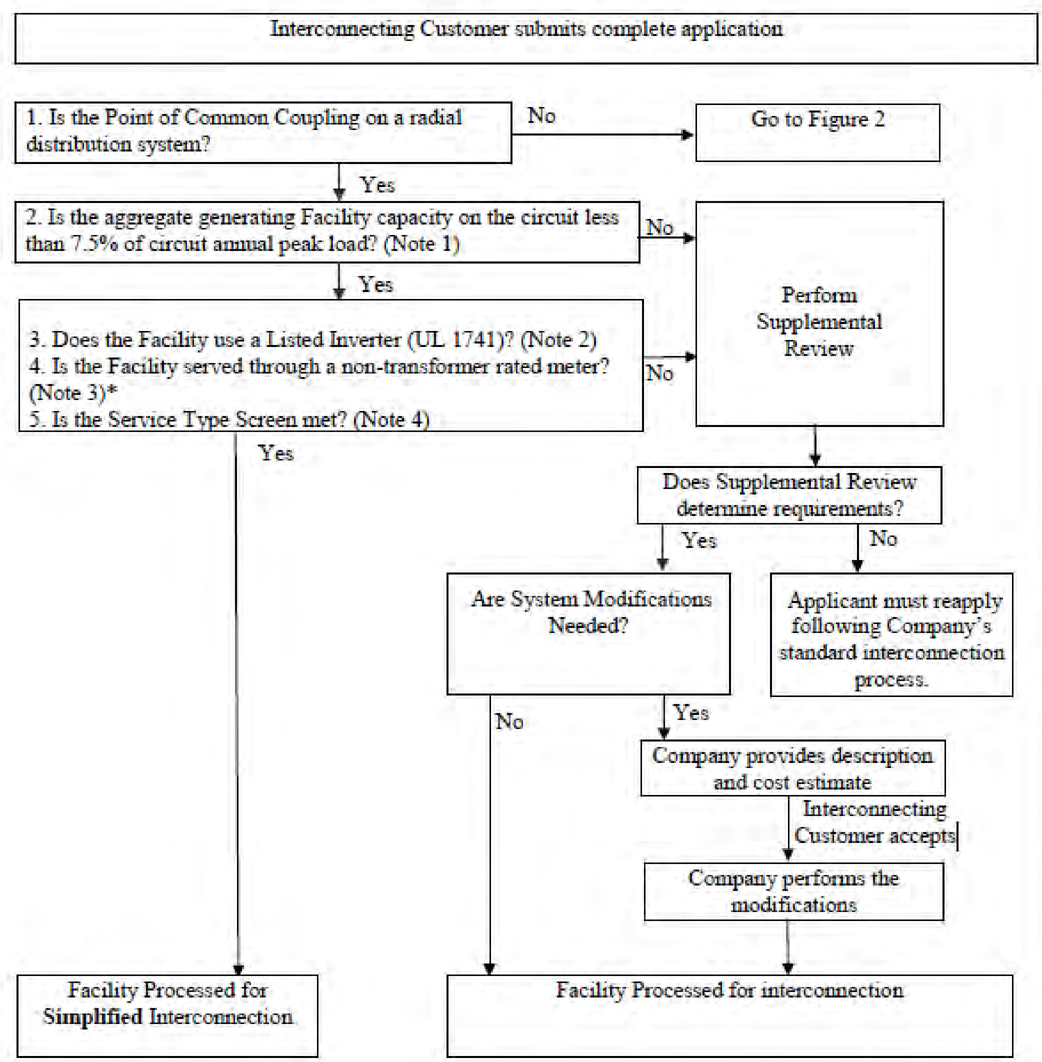
vii. Fees

There are no fees for those Facilities that qualify for the Simplified Process on a radial EPS (except in certain cases where a System Modification would be needed for which the Interconnecting Customer would pay).

In cases where the Facility is larger than 10 kVA, or does not pass the other screens, a Supplemental Review will be conducted. In these instances, the Company will provide a cost estimate to do a Supplemental Review to the Interconnecting Customer.

This review is charged as shown on page 40. If Company services are needed to install temporary metering to complete the Supplemental Review, then these charges will also be included as part of the overall review.

Figure 1 – Inverter Based Simplified Interconnection Process



Explanatory Notes to Accompany Figure 1

1. On a typical radial distribution EPS circuit ("feeder") the annual peak load is measured at the substation circuit breaker, which corresponds to the supply point of the circuit. A circuit may also be supplied from a tap on a higher-voltage line, sometimes called a sub-transmission line. On more complex radial EPSs, where

bidirectional power flow is possible due to alternative circuit supply options ("loop service"), the normal supply point is the loop tap.

2. New Hampshire has adopted UL1741 (Inverters, Converters and Charge Controllers for Use in Independent Power Systems) as an acceptable standard for power systems to comply with IEEE Std 1547 and 1547.1. Equipment listed to UL1741 by a nationally recognized testing laboratory will be considered in compliance with IEEE Std 1547 and 1547.1. An Interconnecting Customer should contact the Facility supplier(s) to determine if its equipment has been listed to either of these standards.

3. Facilities connected to the utility through a transformer rated meter will be required to install a fully rated, lockable disconnect switch. The disconnect switch will be located near the service entrance for use by utility personnel.

4. This screen includes a review of the type of electrical service provided to the Interconnection Customer, including the service transformer configuration and service type to limit the potential for creating unacceptable voltage imbalance, over-voltage or under-voltage conditions, or service equipment overloads on the Company EPS due to a mismatch between the size and phasing of the energy source, the service loads fed from the service transformer(s), and the service equipment ratings.

To be eligible for the Simplified Process, a Listed inverter-based Facility must be either (1) a single-phase unit on a customer's local EPS receiving single-phase secondary service at the PCC from a single-phase service transformer, or (2) a three-phase unit on a customer's local EPS receiving three-phase secondary service at the PCC from a three-phase transformer configuration.

If the proposed Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.

Figure 2 – Simplified Interconnection to Networks

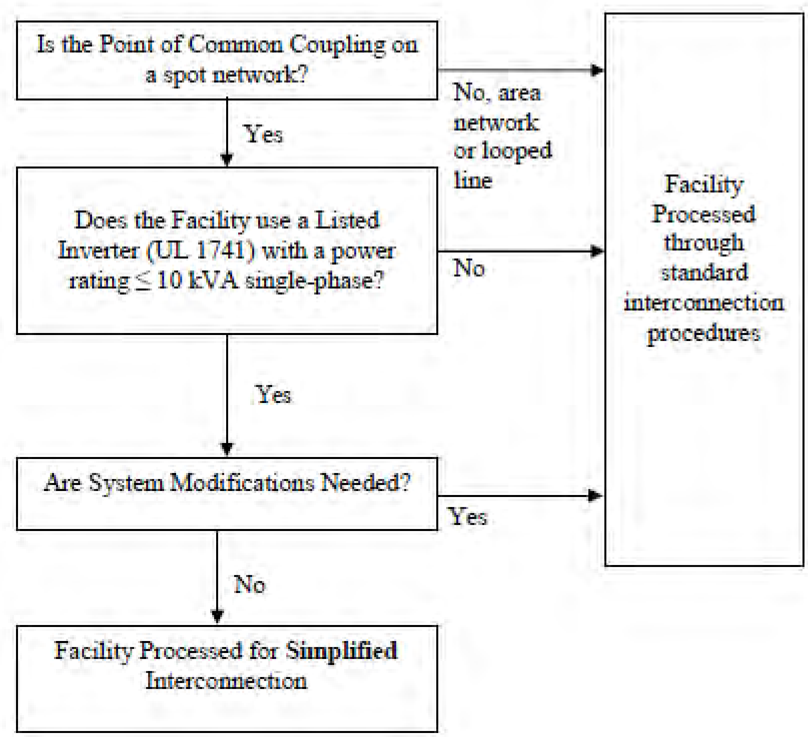


Table 1 – Time Frames

Review Process	Simplified	Simplified Spot Network
Eligible Facilities	Listed Small Inverter	Listed Inverter ≤ 10 kVA single-phase
Review Application for completeness	10 days	10 days
Complete Review of all screens	10 days	Site review 30 days if load is known or can be estimated 90 days if load has to be metered
Complete Supplemental Review (if needed) – Note 1		
Total Maximum Days	20 days	100 days
Notice/ Witness Test	< 1 day with 10 day notice or by mutual agreement	1 day with 10 day notice or by mutual agreement
Send Approval to Interconnector		

NOTE 1: When a Supplemental Review is involved, the timelines for a Simplified Process no longer apply. However, the Company will complete the Supplemental Review within 40 days.

Exhibit A – Simplified Process Interconnection Application Instructions
(please do not submit this page)

i. General Information: If you, the Interconnecting Customer, wish to submit an application to interconnect your generating Facility using the Simplified Process (reference Section iii of the Interconnection Standard for eligibility) please fill out the attached application form completely (not including this page of instructions), including your signature in the space provided. Interconnections that may be eligible for this Simplified Process include UL 1741-Listed inverter-based Facilities that are either (1) connecting to radial electric power systems with power ratings of ≤100 kVA, or (2) connecting to spot network electric power systems with power ratings of ≤10 kVA single-phase. Please attach any documentation provided by the inverter manufacturer concerning the UL 1741. Facilities larger than 10 kVA will be required to install a fully rated lockable switch near the service entrance for use by utility personnel.

ii. Mail all material to: Liberty Utilities, Customer Relations, 9 Lowell Road, Salem, NH 03079 or Email to SMNHNetMetering@libertyutilities.com

iii. The Simplified Process is as follows:

1. Application process:
   a) Interconnecting Customer submits a Simplified Application filled out properly and completely.
   b) Interconnecting Customer submits a non-professional engineer stamped electrical one-line diagram of the proposed system.
   c) Company evaluates the application for completeness and notifies the Interconnecting Customer within 10 business days of receipt that the application is or is not complete and, if not, advises what is missing.
   d) Company verifies Facility equipment can be interconnected safely and reliably.
   e) If approved, the Company signs the application and returns a copy to the Interconnecting Customer.
   f) Upon receipt of the signed application, the Interconnecting Customer installs the Facility. Then the Interconnecting Customer arranges for inspection of the completed installation by the local electrical wiring inspector, or other authority having jurisdiction, and this person signs the Certificate of Completion. If the Facility was installed by an electrical contractor, this person also fills out the Certificate of Completion.
   g) In certain circumstances, the Company will require the Interconnecting Customer to pay for System Modifications. If so, a description of work and an estimate will be sent back to the Interconnecting Customer for approval. The Interconnecting Customer would then approve via a signature and payment for the System Modifications. If the Interconnecting Customer approves, the Company performs the System Modifications. Then, the Company signs the application and sends the approved application back to the Interconnecting Customer.

h) The Interconnecting Customer returns the Certificate of Completion to the Company.
i) Following receipt of the Certificate of Completion, the Company may inspect the Facility for compliance with standards by arranging for a Witness Test. Except for a short test by the installer to confirm the system works properly, the Interconnecting Customer has no right to operate in parallel (interconnect) until a Witness Test has been performed or has been previously waived by the Company on the Application Form. The Company is will make every attempt to complete this Witness Test within 10 business days of its receipt of the Certificate of Completion. All projects larger than 10 kVA will need to be witness tested, unless waived by the Company.
j) Assuming the wiring inspection and/or Witness Test is satisfactory, the Company notifies the Interconnecting Customer in writing that interconnection is authorized. If the Witness Test is not satisfactory, the Company has the right to disconnect the Facility, and will provide information to the Interconnecting Customer describing clearly what is required for approval.
k) Contact Information: You must provide the contact information for the legal applicant (i.e. the Interconnecting Customer). If other parties are responsible for interfacing with the Company, you should provide their contact information as well.
l) Ownership Information: Please enter the legal names of the owner or owners of the Facility.
m) Generating Facility Information: Please consult an actual electric bill from the Electric Service Company and enter the correct Account Number and meter number on this application. If the facility is to be installed in a new location, a temporary number may be assigned by the Electric Company.
n) Confidentiality: Information on this form will be shared with the Commission and other State Agencies as required.
o) UL 1741 Listed The standard UL 1741.1 dated May, 2007 or later, “Inverters, Converters, and Controllers for Use in Independent Power Systems,” addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers choose to submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL 1741.1. This term “Listed” is then marked on the equipment and supporting documentation.

53. Simplified Process Interconnection Application and Service Agreement

Contact Information - Legal name and address of Interconnecting Customer (or, Company name, if appropriate):
Customer/Company Name ______________________________ Contact Person______________
Mailing Address____
City________________________ State______ Zip Code_______ Email___________________
Phone - Daytime __________________ Evening_______________ Fax ___________________

Alternative Contact Information (e.g, system installation contractor or coordinating company, if appropriate):
Name____ Contact Person______________
Mailing Address____
City________________________ State______ Zip Code_______ Email___________________
Phone - Daytime __________________ Evening_______________ Fax ___________________

Electrical Contractor Contact Information (if appropriate)
Name____________________________ Contact Person______________ License # _________
Mailing Address____
City________________________ State______ Zip Code_______ Email___________________
Phone - Daytime __________________ Evening_______________ Fax ___________________

Facility Information
Address of facility ____
Mailing Address____
City____________________ State______ Zip Code_______ Electric Supply Co.____________
Account # _______________ Meter #_______________ Gen/Inverter Manu ________________
Model Name and #__________________________ Quantity____ Nameplate Rating (kW)_____
(kVa) _______ (AC volts) ____ Single Phase ___ Three Phase ___ Battery Backup Y __ N __
Net Metering: If renewably fueled, will the account be Net Metered? Y__ N __
Prime Mover: Photovoltaic __ Recip'g Engine __ Fuel Cell __ Turbine __ Other _____________
Energy Source: Solar __ Wind __ Hydro __ Diesel __ Nat Gas __ Fuel Oil __ Other __________
UL 1741.1 (IEEE1547.1) Listed? Y __ N __ External Manual Disconnect Y__ N__
Estimated Install Date ____________________ Estimated In-Service Date __________________
Production Meter Requested Y___N___ System Design Capacity ______kW/kVa

Interconnecting Customer Signature
I hereby certify that, to the best of my knowledge, all of the information provided in this application is true and I agree to the Terms and Conditions on the following page:
Please attach any documentation provided by the inverter manufacturer describing the inverter's UL 1741 listing.

Customer Signature ___________________________ Title _______________ Date_________

……………………………………………………………………………………………………

Approval to Install Facility (For Company Use Only): Installation of the Facility is approved contingent upon the terms and conditions of this Agreement, and agreement to any system modifications, if required.
Are system modifications required? Y__ N__

Company Signature __________________________ Title___________________ Date_________
Company waives inspection/Witness test? Y__ N__
Application Number ___________________

54. Terms and Conditions for Simplified Process Interconnections

1. Construction of the Facility. The Interconnecting Customer may proceed to construct the Facility in compliance with the specifications of its Application once the Approval to Install the Facility has been signed by the Company.

2. Interconnection and operation. The Interconnecting Customer may operate Facility and interconnect with the Company's system once all of the following has occurred.

3. Municipal Inspection. Upon completing construction, the Interconnecting Customer will cause the Facility to be inspected or otherwise certified by the local electrical wiring inspector with jurisdiction.

4. Certificate of Completion. The Interconnecting Customer returns the Certificate of Completion to the Agreement to the Company at address noted.

5. Company has completed or waived the right to inspection.

6. Company Right of Inspection. The Company will make every attempt within ten (10) business days after receipt of the Certificate of Completion, and upon reasonable notice and at a mutually convenient time, conduct an inspection of the Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with the Interconnection Standard. The Company has the right to disconnect the Facility in the event of improper installation or failure to return Certificate of Completion. All projects larger than 10 kVA will be witness tested, unless waived by the Company.

7. Safe Operations and Maintenance. The Interconnecting Customer shall be fully responsible to operate, maintain, and repair the Facility.

8. Disconnection. The Company may temporarily disconnect the Facility to facilitate planned or emergency Company work.

9. Metering and Billing. All renewable Facilities approved under this Agreement that qualify for net metering, as approved by the Commission from time to time, and the following is necessary to implement the net metering provisions:

10. Interconnecting Customer Provides: The Interconnecting Customer shall furnish and install, if not already in place, the necessary meter socket and wiring in accordance with accepted electrical standards. In some cases the Interconnecting Customer may be required to install a separate telephone line.

11. Company Installs Meter. The Company will make every attempt to furnish and install a meter capable of net metering within ten (10) business days after receipt of the Certificate of

Completion if inspection is waived, or within 10 business days after the inspection is completed, if such meter is not already in place.

i. Indemnification

Interconnecting Customer and Company shall each indemnify, defend and hold the other, its directors, officers, employees and agents (including, but not limited to, Affiliates and contractors and their employees), harmless from and against all liabilities, damages, losses, penalties, claims, demands, suits and proceedings of any nature whatsoever for personal injury (including death) or property damages to unaffiliated third parties that arise out of, or are in any manner connected with, the performance of this Agreement by that party, except to the extent that such injury or damages to unaffiliated third parties may be attributable to the negligence or willful misconduct of the party seeking indemnification.

ii. Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever.

iii. Termination of Agreement

1. Termination. This Agreement may be terminated under the following conditions:

   a) By Mutual Agreement. The Parties agree in writing to terminate the Agreement.
   b) By Interconnecting Customer. The Interconnecting Customer may terminate this Agreement by providing written notice to Company.
   c) By Company. The Company may terminate this Agreement (1) if the Facility fails to operate for any consecutive 12 month period, or (2) in the event that the Facility impairs or, in the good faith judgment of the Company, may imminently impair the operation of the electric distribution system or service to other customers or materially impairs the local circuit and the Interconnecting Customer does not cure the impairment.

iv. Assignment/Transfer of Ownership of the Facility

This Agreement shall survive the transfer of ownership of the Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

v. Interconnection Standard

These Terms and Conditions are pursuant to the Company's "Interconnection Standards for Inverters Sized Up to 100 kVA" for the Interconnection of Customer-Owned Generating Facilities, as approved by the Commission and as the same may be amended from time to time ("Interconnection Standard"). All defined terms set forth in these Terms and Conditions are as defined in the Interconnection Standard (see Company's website for the complete document).

55. Certificate of Completion for Simplified Process Interconnections

Installation Information **__ Check if owner installed**

Customer/Company Name ______________________________ Contact Person______________
Mailing Address____
City_________________________ State______ Zip Code_______ Email___________________
Phone - Daytime ___________________ Evening_______________ Fax___________________

Address of facility (if different from above)____
Mailing Address____ City ___________________
State______ Zip Code_______ Generation Vendor_____________ Contact Person ___________

I hereby certify that the system hardware is in compliance with Puc 900.

Vendor Signature____ Date____________________

Electrical Contractor Contact Information (if appropriate)
Name______________________________ Contact Person______________ License # _________
Mailing Address____
City_________________________ State______ Zip Code_______ Email___________________
Phone - Daytime ___________________ Evening_______________ Fax____________________

Date of approval to install Facility granted by the Company __________ Installation Date______

Application ID number ____

Inspection

The system has been installed and inspected in compliance with the local Building/Electrical Code of (City/County)
____

Signed by (Local Electrical Wiring Inspector, or attach signed electrical inspection):

Signed: ___________________ Printed: _________________________________Date: ________

Customer Certification

I hereby certify that, to the best of my knowledge, all the information contained in this Interconnection Notice is true and correct. This system has been installed and shall be operated in compliance with applicable electrical standards and the initial startup test required by Puc 905.04 has been successfully completed.

Customer Signature ____ Date ___________

As a condition of interconnection you are required to send/email a copy of this form to:

Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities
Engineering
9 Lowell Road
Salem, NH 03079
Email: SMNHNetMetering@libertyutilities.com

56. Supplemental Review Agreement

This Agreement, dated_________________ , is entered into by and between (name, address)_________________ ("Interconnecting Customer") and the Company, for the purpose of setting forth the terms, conditions and costs for conducting a Supplemental Review relative to the Interconnection Process as defined in Sections iii – x of the Interconnection Standard. This Supplemental Review pertains to the interconnection application the Interconnecting Customer has filed for interconnecting a ____kVA Facility at ________________ (address of Facility).

If the Supplemental Review determines the requirements for processing the application including any System Modifications, then the modification requirements and costs for those modifications will be identified and included in a billing statement sent by the Company to the Interconnecting Customer for authorization and payment. If the Supplemental Review does not determine the requirements, it will include a proposed Impact Study Agreement as part of the Company's standard interconnection process which will include an estimate of the cost of the study.

The Interconnecting Customer agrees to provide, in a timely and complete manner, all additional information and technical data necessary for the Company to conduct the Supplemental Review not already provided in the Interconnecting Customer's application.

All work pertaining to the Supplemental Review that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of the Company and the Interconnecting Customer. Each party shall inform the other in writing of its designated and authorized representative, if different than what is in the application.

The Company shall perform the Supplemental Review for a fee provided in the table below.. The Company anticipates that the Supplemental Review will cost $____. No work will be performed until payment is received.

Project Size (Max AC Rating of Inverters)	Supplemental Review Fee
>10 kW to 30 kW	$125
>30 kW to 50 kW	$500
>50 kW to 100 kW	$1000

Please indicate your acceptance of this Agreement by signing below.

____
Interconnecting Customer

____
Date

57. Line Extensions – Policy 1: Individual Residential Customers

In areas in which Delivery Service by the Company is authorized, the Company will extend its single-phase or three-phase distribution facilities or upgrade its single-phase distribution facilities to three-phase distribution facilities to a maximum of 5,280 feet in length to serve Customers under Residential Delivery Service Rate D and Rate D-10, as follows:

i. Applicability

When an individual residential Customer ("Customer") requests that a distribution line be extended to serve the Customer's single family or duplex home the terms of this policy shall apply.

This policy provides for standard single phase residential service. Service above and beyond standard residential service may result in additional cost to the Customer. Additional information is contained in the Company's "Specification for Electrical Installations" booklet located on the Company's website and the Company' s Terms and Conditions as filed with the New Hampshire Public Utilities Commission.

ii. Temporary Service

This policy shall not apply to lines constructed for temporary service. Temporary service is defined in the Company's Terms and Conditions. The Company should be contacted regarding the cost and availability of temporary service.

iii. Outdoor Lighting

This policy shall not apply to outdoor lighting. All outdoor lighting installations will be made in accordance with the Company's tariffs approved by the New Hampshire Public Utilities Commission. The Company should be consulted regarding street light rates, costs and availability.

iv. Construction of Facilities

1. Line Extension on Public Way and Private Property

No distinction shall be made between line extensions on public ways or private property except where specifically noted.

Pursuant to RSA 370:12, Customers requiring a line extension on private property may opt to hire and pay a private line contractor, licensed by the state and approved by the Company, to construct such power line extension on private property. The contractor shall supply and install all materials as specified by the Company. All line extensions must be designed by the Company and built to its specifications in order for the Company to assume ownership of the line.

The Company has the right to refuse to accept a line extension that does not conform to the Company's specifications. Customers may not contract with private line contractors to construct line extensions along public ways.

2. Overhead Line Extension

The Company shall be responsible for:

a) installing, owning and maintaining all poles, primary and secondary wires, transformers, service drops, meters, etc. that, in its opinion, are required to provide adequate service;
b) designating the location of all Company owned equipment, the service entrance and meter location(s) at the house and,
c) blasting and tree trimming and removal along public ways; the Company may charge the Customer the cost of such blasting and tree trimming and removal if, in the Company' s opinion, such estimated cost is in excess of 50% of the average cost per foot.

The Customer, at no cost to the Company, shall be responsible for blasting and tree trimming and removal on private property in accordance with the Company's specifications and subject to the Company' s inspection.

3. Underground Line Extension

The Company will install, own and maintain a single phase residential service from the Company's distribution system to the service point for residential customers. The responsibilities of the Company and Customer are defined in Electric Service Bulletin No. 750, Specifications for Electrical Installations, found here: https://new-hampshire.libertyutilities.com/uploads/2019%20Version%203.0_ESB750%20Specifications%20for%20Electrical%20Installations.pdf

v. Payment Required

1. Overhead Line Extension

The "Overhead Cost per Foot" will be a predetermined cost per foot calculated by the Company. This cost is located in the Schedule of Fees for Line Extensions in the Company's Terms and Conditions.

The Company will provide a predetermined length of overhead distribution line, plus a service drop per house, free of charge ("Allowed Overhead Line Distance per House"). The service drop is considered to be from the last pole to the house.

The "Allowed Overhead Line Distance per House" will be a predetermined distance per home as stated in the Schedule of Fees for Line Extensions in the Company's Terms and Conditions.

If the total line distance required to serve the house is in excess of the "Allowed Overhead Line Distance per House," there will be a charge to the Customer ("Overhead Installation Charge").\

The "Overhead Installation Charge" payable by the Customer will be equal to the "Overhead Cost per Foot" times the number of feet in excess of the "Allowed Overhead Line Distance per House."

2. Underground Line Extension

The Customer shall pay the estimated cost derived by multiplying the length of the Underground System in excess of Three Hundred (300) feet, including normal service drops, by the average cost per foot on page 76 Section i.1. and adding the result to the excess cost of any padmounted transformers to be installed. The excess cost of a padmounted transformer is the amount by which the cost of a padmounted transformer exceeds the cost of an equivalent pole-mounted transformer. The Customer shall pay all excavating, backfilling, and conduits shall be provided by the Customer subject to approval by the Company.

If an overhead line extension is built in combination with an underground line extension, the credit for the "Allowed Overhead Line Distance" will only be applied once.

If an existing overhead line extension is converted to an underground line extension, the Customer will not receive the credit associated with the first 300 feet.

3. Payment Terms

If the "Overhead/Underground Installation Charge" is less than $3,000, the Customer will be required to pay the entire amount before the start of the construction.

If the "Overhead/Underground Installation Charge" is $3,000 or greater, the Customer will have the option to either pay the entire amount before the start of the construction, or sign an agreement to pay the amount in 60 equal monthly payments, plus interest at the rate of interest applicable to the Company's Customer deposit accounts at the time of execution of the payment agreement.

The Company reserves the right to place a lien on the property until such time that the obligation is fulfilled.

4. More Than One Customer

Where overhead service is requested by more than one Customer under this policy at the same time, for the same line, the "Overhead Installation Charge" will be apportioned among those Customers, based on the amount of line attributable to each Customer. The Company will determine the equitable apportioning of the total estimated construction costs between the Customers. The calculation of the "Overhead Installation Charge" shall allow for a credit equal to "Allowed Overhead Line Distance per House" for each Customer.

5. Customer Added After Initial Construction

At the original Customer's request, if a new Customer (or group of Customers) is supplied service from facilities constructed under this policy, and if such service begins within five years from the date of the first payment received by the Company from the original Customer or group of Customers, the Company will require such new Customer(s) to make a prorated contribution to the payment of the initial "Overhead Installation Charge." Any contribution received from a new Customer(s) will be used to proportionately reduce the original Customer's "Overhead Installation Charge." The Company will determine the equitable apportioning of the total estimated construction costs between the Customers. However, no refunds will be paid in excess of the original Customer(s) "Overhead Installation Charge." In addition, a credit for the "Allowed Overhead Line Distance per House" for each Customer will be applied.

6. Change of Customer

The Customer must agree, as a condition for the line extension monthly payments, that if the Customer sells, leases or otherwise transfers control and use of the home to another individual ("New Occupant"), and such "New Occupant" opens a new account with the Company, the Customer will obtain an agreement from the "New Occupant" to pay the remaining balance as prescribed in the agreement of the Overhead Installation Charge that would have been owed by the Customer at that location. Unless the "New Occupant" signs a new superseding payment agreement with the Company, the original Customer will remain personally liable for the balance owed.

7. Line Extension Agreement

The Company may require the Customer to sign an agreement setting forth the terms of this policy and any other terms that the Company deems are reasonably necessary in connection with the installation to the Customer's home, provided that such terms are not inconsistent with the terms expressed in this policy.

The Company, at its sole discretion, may refuse the request for a line extension if appropriate permits and easements cannot be obtained or if applicable codes and standards cannot be met.

The Company will begin construction when the service agreement and easement (if required) are signed and the payment is received.

The Company may, at its option, decline to undertake construction during the period of December 1 to April 1 of each year.

vi. Failure of Underground Facilities Which are the Subject of Customer Ownership

Individual residential line extensions installed prior to January 1, 2019, are owned by the Customer and thus the Customer is responsible for replacement of facilities owned by the customer, if failure occurs. At the request of the Customer, the Company will replace the underground line extension at the Customer's cost calculated in v.2. above. The Customer will be required to sign an authorization agreement, install the conduit to the Company's specifications, and once complete, the Company will replace the cable, and take ownership. The Customer is responsible for all requirements under iv.3. prior to installation of the replacement line extension including removal of all required foundations (except for Company boxpad foundations), handholes, manholes, grounding systems, primary and secondary cable, and conduit including, but not limited to, spacers, glue and pulling strings. The Customer is responsible for any requirement regarding the removal or abandonment of the Customer Owned failed system on private property. Section vi. Is not intended for emergency situations.

58. Line Extensions – Policy 2: Residential Developments

i. General Applicability

When a developer, contractor, builder or other entity other than an individual residential Customer ("Customer") proposing to construct individual homes or a residential development of single family or duplex homes, requests that distribution lines be constructed to serve the homes or development and no suitable distribution facilities exist, the terms of this policy shall apply. This policy applies to a Customer whenever it is building more than one single family or duplex home. Policy 2 applies to the subdivision mainline only. Individual services will fall under Policy 1.

This policy provides for standard single phase residential service. Service above and beyond standard residential service may result in additional cost to the Customer. Additional information is contained in the Company's "Specification for Electrical Installation" booklet located on the Company's website and the Company's Terms and Conditions as filed with the New Hampshire Public Utilities Commission.

ii. Temporary Service

This policy shall not apply to lines constructed for temporary service. Temporary service is defined in the Company's Terms and Conditions. The Company should be contacted regarding the cost and availability of temporary service.

iii. Outdoor Lighting

This policy shall not apply to outdoor lighting. All outdoor lighting installations will be made in accordance with the Company's tariffs approved by the New Hampshire Public Utilities Commission. The Company should be consulted regarding outdoor lighting rates, costs and availability.

iv. Construction of Facilities

1. Line Extension on Public and Private Ways

No distinction shall be made between line extensions on public ways or private ways except where specifically noted.

Pursuant to RSA 370:12, Customers requiring a line extension on private property may opt to hire and pay a private line contractor, licensed by the state and approved by the Company, to construct such power line extension on private property. The contractor shall supply and install all materials as specified by the Company. All line extensions must be designed by the Company and built to its specifications in order for the Company to assume ownership of the line. The Company has the right to refuse to accept a line extension that does not conform to the Company's specifications.

Customers may not contract with private line contractors to construct line extensions along public ways.

2. Overhead Line Extension

The Company shall be responsible for:

a) installing, owning and maintaining all poles, primary and secondary wires, transformers, service drops, meters, etc. that, in its opinion, are required to provide adequate service;
b) designating the location of all Company owned equipment, excluding street lights, and the service entrance and meter location(s) at each house, and
c) blasting and tree trimming and removal along public ways; the Company may charge the Customer the cost of such blasting and tree trimming and removal if in the Company's opinion such estimated cost is in excess of 50% of the average cost per foot.

The Customer, at no cost to the Company, shall be responsible for blasting and tree trimming and removal on private property, including roadways not accepted as public, and ways by the municipality, in accordance with the Company's specifications and subject to the Company's inspection.

The Company may, at its discretion, construct the distribution line in segments, rather than all at once in the proposed development. The Company may, at its option, be exempt from undertaking construction during the period of December 1 to April 1 each year.

3. Underground Line Extension

The Company will install, own and maintain a single phase residential service from the Company's distribution system for residential customers. The responsibilities of the Company and Customer are defined in Electric Service Bulletin No. 759A, Specifications for Electrical Installations – Underground Residential Distribution (URD) Installation and Responsibility Guide, found here: https://new-hampshire.libertyutilities.com/uploads/URD%20Installation%20%20Responsibility%20Guide%20(ESB%20759A)%20-%202018.pdf

The Company may, at its discretion, construct the distribution line in segments, rather than all at once in the proposed development. The Company may, at its option, be exempt from undertaking construction during the period of December 1 to April 1 each year.

4. Plans and Other Documents

The total number of house lots proposed to be constructed will be provided in advance to the Company by the Customer, along with a complete copy of the subdivision plans approved by the planning board in the municipality, if such is required by the municipality. The Company need not begin design work prior to receipt of the approved plans.

The Company may require the Customer to provide, in advance and at no cost to the Company:

a) a copy of the approval of the planning board for the subdivision;
b) a copy of all permits and approvals that have been obtained for constructing the development;
c) easements, drafted by the Company, for all facilities required to serve the development;
d) the name and address of the financial institution providing financing for the development, including a contact person and phone number; a copy of
e) a street light proposal for the development, approved by the municipality, or written notice from the municipality that street lighting will not be required;
f) if installation is requested after construction is complete, additional costs, may be borne by the municipality and/or Customer if the tariff does not collect all costs of construction;
g) a schedule of Customer's best estimate for the construction of homes in the development; and such other reasonable information that may be requested to confirm the viability of the development.

v. Payment Required

1. Overhead Installation Charge

Centerline Feet Calculation: The centerline feet calculation will be defined as the total length of all roadways within the subdivision.

The "Overhead Cost -per Centerline Foot" will be a predetermined cost per centerline foot calculated by the Company. This cost is located in Schedule of Fees for Line Extensions in the Company's Terms and Conditions.

The "Overhead Cost per Centerline Foot" assumes that service points are in close proximity to roadways. The Company reserves the right to require the Customer to pay any excess costs to reach the service point when more than one span of wire is required to reach the service point from the roadway.

The Company will provide a predetermined length of centerline feet per house lot free of charge ("Allowed Overhead Distance per House").The "Total Allowed Overhead Distance" for the development is equal to the number of house lots times the "Allowed Overhead Distance per House." The predetermined "Allowed Overhead Distance per House" can be located in Schedule of Fees for Line Extensions in the Company's Terms and Conditions.

If the total centerline feet within the development are greater than the "Total Allowed Overhead Distance," then there will be a charge to the Customer ("Overhead Installation Charge").

The "Overhead Installation Charge" will be equal to the "Overhead Cost Per Centerline Foot" times the number of centerline feet in excess of the "Total Allowed Overhead Distance," and shall be paid by the Customer in advance of the Company's construction and is non-refundable if the line is built.

2. Underground Installation Charge

The "Underground Cost per Centerline Foot" will be a predetermined cost per centerline foot calculated by the Company. This cost is located in the Schedule of Fees for Line Extensions in the Company's Terms and Conditions.

The "Underground Cost per Centerline Foot" is calculated assuming all Company facilities terminate within 2 feet of the roadway. The Company will provide a predetermined length of centerline feet per house lot free of charge ("Allowed Underground Distance per House").

The "Total Allowed Underground Distance" for the development is equal to the number of house lots times the "Allowed Underground Distance per House." The predetermined "Allowed Underground Distance per House" can be located on page 76 of this tariff.

If the total centerline feet within the development are greater than the "Total Allowed Underground Distance", then there will be a charge to the Customer ("Underground Installation Charge").

The "Underground Installation Charge" will be equal to the "Underground Cost Per Centerline Foot" times the number of centerline feet in excess of the "Total Allowed Underground Distance." The "Underground Installation Charge" shall be paid by the Customer in advance of the Company's construction and is non-refundable if the line is built.

For underground residential developments requesting underground service to the home, the request will fall under Policy 1.

3. Additional Advance Payments

If there is a cost to get to the limits of the development, the Company may charge the Customer this additional cost.

4. Line Extension Agreement

The Company may require the Customer to sign an agreement setting forth the terms of this policy and any other terms that the Company deems are reasonably necessary in connection with the installation to the Customer's home, provided that such terms are not inconsistent with the terms expressed in this policy.

The Company, at its sole discretion, may refuse the request for a line extension if appropriate permits and easements cannot be obtained or if applicable codes and standards cannot be met.
The Company will begin construction when the service agreement and easement (if required) are signed and the payment is received.

The Company may, at its option, decline to undertake construction during the period of December 1 to April 1 of each year.

59. Line Extensions – Policy 3: Individual Commercial and Industrial Customers

i. General Applicability

When a commercial or industrial Customer, developer, contractor, builder or other entity ("Customer") requests service for new or increased load to a single lot, the terms of this policy shall apply.

Additional information is contained in the Company's "Specification for Electrical Installation" booklet located on the Company's website and the Company's Terms and Conditions as filed with the New Hampshire Public Utilities Commission.

ii. Temporary Service

This policy shall not apply to lines constructed for temporary service. Temporary service is defined in the Company's Terms and Conditions. The Company should be contacted regarding the cost and availability of temporary service.

iii. Outdoor Lighting

This policy shall not apply to outdoor lighting. All outdoor lighting installations will be made in accordance with the Company's tariffs approved by the New Hampshire Public Utilities Commission. The Company should be consulted regarding outdoor lighting rates, costs and availability.

iv. Construction of Facilities

1. Line Extension on Public and Private Ways

No distinction shall be made between line extensions on public ways or private ways except where specifically noted.

Pursuant to RSA 370:12, Customers requiring a line extension on private property may opt to hire and pay a private line contractor, licensed by the state and approved by the Company, to construct such power line extension on private property. The contractor shall supply and install all materials as specified by the Company. All line extensions must be designed by the Company and built to its specifications in order for the Company to assume ownership of the line. The Company has the right to refuse to accept a line extension that does not conform to the Company's specifications. Customers may not contract with private line contractors to construct line extensions along public ways.

2. Overhead Line Extension

When overhead service is requested, the Company shall be responsible for:

a) installing, owning and maintaining all poles, primary and secondary wires, transformers, service drops, meters, etc. that, in its opinion, are required to provide adequate service;
b) designating the location of all Company owned equipment, excluding street lights, and the service entrance and meter location(s) and.
c) blasting and tree trimming and removal along public ways; the Company may charge the Customer the cost of such blasting and tree trimming and removal if, in the Company's opinion, such cost is excessive. The cost of the blasting and tree trimming is included in (C) of the formula which is found in section 59.vi.1.

The Customer, at no cost to the Company, shall be responsible for blasting and tree trimming and removal on private property, including roadways not accepted as public ways by the municipality, in accordance with the Company' s specifications and subject to the Company's inspection.

3. Underground Line Extension

The Company will install, own and maintain primary service from the Company's distribution system for commercial and industrial customers. The responsibilities of the Company and Customer are defined in Electric Service Bulletin No. 759B, Specifications for Electrical Installations – Underground Commercial Distribution (UCD) Installation and Responsibility Guide found here: https://new-hampshire.libertyutilities.com/uploads/UCD%20Installation%20%20Responsibility%20Guide%20(759B)%20-%202018.pdf

The Company may, at its option, be exempt from undertaking construction during the period of December 1 to April 1 each year.

4. Plans and Documentation

The Company may require the Customer to provide, in advance of engineering design and at no cost to the Company:

a) a complete copy of construction plans including the site plans approved by the planning board in the municipality, if such is required by the municipality;

the estimated new or additional electrical loads, as far as is known by the Customer; or the names and estimated loads of proposed tenant or buyer for the building or the proposed type of occupant, as far as is known by the Customer;

b) barring a known occupant, the Customer's best estimates of the likely load of the proposed building; all applicable documents required for the Company to prepare an easement for its facilities to be installed on private property;

c) a copy of the approval of the planning board for the subdivision, if such is required;

d) a copy of all permits and approvals that have been obtained for construction;

e) the name and address of the financial institution providing financing for the Customer, including a contact person and phone number;

a schedule of the Customer's best estimate for construction;

and such other reasonable information that may be requested

v. Payment Required

1. Construction Advance

Facilities in excess of those required to meet the distribution service requirements of the Customer are outside the scope of this policy and may entail additional payments from the Customer.

In accordance with the Formula below (the "Formula"), the Company shall determine whether a payment, by the Customer, of a Construction Advance shall be required. The Construction Advance shall be paid in full prior to the start of any construction.

Construction Advance (A) = C – (R/k)

Where:

A = the Construction Advance paid to the Company by the Customer.

C = the total estimated cost of construction for facilities required exclusively to meet the distribution service requirement of the Customer. This cost includes capital and non-capital costs. Where these new or upgraded facilities are not solely to provide service to the Customer, the Company shall appropriately apportion these costs.

R = the annual Distribution Revenue derived from the Customer within the first year following the completion of the Company's construction of the facilities.

k = the annual carrying charges measured at the time of construction, expressed as a decimal.

Where the calculation of (A) results in a positive number, a construction advance in the amount of (A) shall be required from the customer. Where the calculation of (A) results in a negative number, (A) shall be considered to be zero. When the calculation of (A) results in a construction advance of $500 or less, the payment of the construction advance will be waived.

The Company shall exercise good faith in making each estimate and determination required above.

Any revenues from Energy Service shall be excluded from this calculation.

2. Refund

Whenever the Company collects a Construction Advance from the Customer, the Customer has the option to request the Company to perform a one-time recalculation of the Construction.

Advance payment using actual construction costs and actual distribution revenue to determine if a refund of all or a portion of the original payment is warranted. The request for the one-time review may be made at any time between twelve and thirty-six months after commencement of delivery of electricity.

To determine the refund the Construction Formula shall be modified as follows:

C = the actual cost of construction. If the actual cost of construction exceeds the estimate, then the estimated cost of construction shall be used. This cost includes capital and non-capital costs. Where these new or upgraded facilities are not solely to provide service to the Customer, the Company shall appropriately apportion these costs.

R = the actual additional annual distribution revenue for the most recent twelve months.

k = the annual carrying charge factor, expressed as a decimal.

If a lower or negative (A) results from applying the Formula as so modified, and if, in the Company's opinion, a risk does not exist regarding either a future reduction in the level of the Customer's usage or the collectability of the Customer's account, then the Company shall refund a portion of, or the entire calculated Construction Advance or the full cost of construction, without interest. In no case shall the amount refunded exceed the original construction advance (A), nor shall the review result in additional payments from the Customer, unless excess costs are caused by the Customer.

3. Additional Payment

When in the Company's opinion, more than 32 hours of engineering is required to determine the method of service or prepare construction estimates, the Company will estimate the cost of such engineering. The Company may charge the Customer the excess of 32 hours of engineering before engineering begins. If construction is undertaken, this payment will be applied to any required construction advance. If construction is not undertaken, the Company will refund any balance not spent. If no Construction Advance is required, the entire Additional Advance Payment will be refunded unless excess costs are caused by the Customer.

vi. Failure of Primary Underground Facilities Which are the Subject of Customer Ownership

Individual C&I customer line extensions installed prior to January 1, 2019, are owned by the Customer and thus the Customer is responsible for replacement of facilities owned by the customer, if failure occurs. At the request of the Customer, the Company will replace the underground line extension at the Customer's cost. The Customer will be required to sign an authorization agreement, install the conduit to the Company's specifications, and once complete, the Company will replace the cable, and take ownership. The Customer is responsible for all requirements under iv.3. prior to installation of the replacement line extension including removal of all required foundations (except for Company boxpad foundations), handholes, manholes, grounding systems, primary cable, and conduit including, but not limited to, spacers, glue and pulling strings. The Customer is responsible for any requirement regarding the removal or abandonment of the Customer Owned failed system on private property. Section vi. is not intended for emergency situations.

The Company may be the contractor of last resort for incidental repairs, which does not result in ownership of the customer-owned underground primary service.

60. Line Extensions – Policy 4: Commercial and Industrial Developments

i. Applicability

When a developer, contractor, builder or other entity ("Customer") proposes to construct a commercial or industrial development and no suitable distribution facilities exist, the terms of this policy shall apply. For the purposes of this policy, commercial or industrial Customers shall include condominiums, apartments or mobile home complexes.

Additional information is contained in the Company's "Specification for Electrical Installation" booklet located on the Company's website and the Company's Terms and Conditions as filed with the New Hampshire Public Utilities Commission.

ii. Temporary Service

This policy shall not apply to lines constructed for temporary service. Temporary service is defined in the Company's Terms and Conditions. The Company should be contacted regarding the cost and availability of temporary service.

iii. Outdoor Lighting

This policy shall not apply to outdoor lighting. All outdoor lighting installations will be made in accordance with the Company's tariffs approved by the New Hampshire Public Utilities Commission. The Company should be consulted regarding outdoor lighting rates, costs and availability.

iv. Construction of Facilities

1. Line Extension on Public and Private Ways

No distinction shall be made between line extensions on public or private ways except where specifically noted.

Pursuant to RSA 370:12, Customers requiring a line extension on private property may opt to hire and pay a private line contractor, licensed by the state and approved by the Company, to construct such power line extension on private property. The contractor shall supply and install all materials as specified by the Company. All line extensions must be designed by the Company and built to its specifications in order for the Company to assume ownership of the line. The Company has the right to refuse to accept a line extension that does not conform to the Company's specifications. Customers may not contract with private line contractors to construct line extensions along public ways.

2. Overhead Line Extension

When overhead service is requested, the Company shall be responsible for:

a) installing, owning and maintaining all poles, primary and secondary wires, transformers, service drops, meters, etc., that, in its opinion, are required to provide adequate service;
b) designating the location of all Company owned equipment, excluding street lights, and the service entrance and meter location(s) and,
c) blasting and tree trimming and removal along public ways; the Company may charge the Customer the cost of such blasting and tree trimming and removal if, in the Company's opinion, such cost is excessive. The cost of the blasting and tree trimming is included in (C) of the formula which is found in section 60.vi.1.

The Customer, at no cost to the Company, shall be responsible for blasting and tree trimming and removal on private property, including roadways not accepted as public ways by the municipality, in accordance with the Company' s specifications and subject to the Company's inspection.

The Company may, at its discretion, construct the distribution line in segments, rather than all at once in the proposed development. The Company may, at its option, be exempt from undertaking construction during the period of December 1 to April 1 each year.

3. Underground Line Extension

The Company will install, own and maintain commercial service from the Company's distribution system for customers. The responsibilities of the Company and Customer are defined in Electric Service Bulletin No. 759B, Specifications for Electrical Installations – Underground Commercial Distribution (UCD) Installation and Responsibility Guide found here: https://new-hampshire.libertyutilities.com/uploads/UCD%20Installation%20%20Responsibility%20Guide%20(759B)%20-%202018.pdf

The Company may, at its discretion, construct the distribution line in segments, rather than all at once in the proposed development. The Company may, at its option, be exempt from undertaking construction during the period of December 1 to April 1 each year.

4. Plans and Documentation

The Company may require the Customer to provide, in advance of engineering design and at no cost to the Company, the following:

a) a complete copy of construction plans including the subdivision plans approved by the planning board in the municipality, if such is required by the municipality;
b) the estimated new or additional electrical loads, as far as is known by the Customer; or the names and estimated loads of proposed tenants or buyers for each building or the proposed type of occupant, as far as is known by the Customer; barring a known occupant, the Customer's best estimates of the likely load of each proposed building;
c) all applicable documents required for the Company to prepare an easement for its facilities to be installed on private property;
d) a copy of the approval of the planning board for the subdivision, if such is required;
e) a copy of all permits and approvals that have been obtained for construction;
f) the name and address of the financial institution providing financing for the Customer, including a contact person and phone number;
g) a copy of a street light proposal for the development, approved by the municipality, or written notice from the municipality that street lighting will not be required. If installation is requested after construction is complete, additional cost may be borne by the municipality and/or Customer if the appropriate tariff does not collect all costs of construction;
h) a schedule of the Customer's best estimate for construction; and
i) such other reasonable information that may be requested.

v. Payment Required

1. Construction Advance

The Company will determine the roadway infrastructure required to meet the distribution service requirements of the commercial development.

In accordance with the Formula below (the "Formula"), the Company shall determine whether a payment, by the Customer, of a Construction Advance shall be required. The "Allowed Credit per Buildable Lot" (B) will be a predetermined cost calculated by the company. This cost is located in the Schedule of Fees for Line Extensions in the Company's Terms and Conditions. The Construction Advance shall be paid in full prior to the start of any construction.

Construction Advance (A) = C- (B*N)

Where:

A = the Construction Advance paid to the Company by the Customer

C = the total estimated cost of construction for facilities required along the traveled way to meet the distribution service requirements of the development. This cost includes capital and non-capital costs. Where these new or upgraded facilities are not solely to provide service to the Customer, the Company shall appropriately apportion these costs.

B = Allowed Credit per buildable lot
N = Number of buildable lots

Where the calculation of (A) results in a positive number, a construction advance in the amount of (A) shall be required from the Customer. Where the calculation of (A) results in a negative number, (A) shall be considered to be zero. When the calculation of (A) results in a construction advance of $500 or less, the payment of the construction advance will be waived.

The Company shall exercise good faith in making each estimate and determination required above.

Any revenues from Energy Service shall be excluded from this calculation.

2. Additional Payment

When in the Company's opinion, more than 60 hours of engineering is required to determine the method of service or prepare construction estimates, the Company will estimate the cost of such engineering. The Company may charge the Customer the excess of 60 hours before engineering begins. If construction is undertaken, this payment will be applied to any required construction advance. If construction is not undertaken, the Company will refund any balance not spent. If no Construction Advance is required, the entire Additional Advance Payment will be refunded.

3. Additional Advance Payments

If there is a cost to get to the limits of the development, the Company may charge the Customer this additional cost.

61. Schedule of Fees for Line Extensions

i. Policy 1

2. Allowed Overhead/Underground Distance Per House:

a) 300 feet or 1 pole, whichever is greater

b) Overhead Cost per Foot greater than 300 feet

Single Phase	$34.47
Three Phase	Actual Cost

c) Excess Underground Cost per Foot greater than 300 feet:

Single Phase Service	$13.17
Three Phase Service	Actual Cost

The Customer is given a credit equal to the cost of up to 300 feet of overhead or underground distribution line towards the construction cost and the Customer pays for the costs in excess of the amount of the credit.

ii. Policy 2

1. Allowed Overhead Distance per House	100 feet
Single Phase Overhead Cost per Foot	$34.47
Three Phase Overhead Cost per Foot	Actual Cost
2. Allowed Underground Distance per House	100 feet
Single Phase Underground Cost per Centerline Foot	$15.66
Three Phase Underground Cost per Centerline Foot	Actual Cost

3. Individual services will fall under Policy 1.

iii. Policy 4

1. Overhead

B = Allowed Credit per Buildable Lot $4,500

2. Underground

B = Allowed Credit per Buildable Lot $4,500

Policy 3 fees are calculated on actual costs without any credit for footage or buildable lots.

62. Terms and Conditions for Competitive Suppliers

i. General Applicability

a) The following Terms and Conditions shall apply to every registered Competitive Supplier within the State of New Hampshire authorized to do business with the Company and their customers.
b) These Terms and Conditions may be revised, amended, supplemented or supplanted in whole or in part from time to time according to the procedures provided in the Commission's Orders or regulations and New Hampshire law. In case of conflict between these Terms and Conditions and any orders or regulations of the Commission, said orders or regulations shall govern.
c) No agent or employee of the Company is authorized to modify any provision contained in these Terms and Conditions or to bind the Company to perform in any manner contrary thereto. Any such modification to these Terms and Conditions or any such promise contrary thereto shall be in writing, duly executed by an authorized officer of the Company, and subject in all cases to applicable statutes and to the orders and regulations of the Commission, and available for public inspection during normal business hours at the business offices of the Company and at the offices of the Commission.

ii. Definitions

Aggregator: Any entity registered with the Commission to negotiate the purchase of electric supply services for retail Customers in New Hampshire.

CEPS Agreement: The contract between the Company and the Competitive Supplier referenced in Section 2.e. below.

Competitive Supplier or Supplier: Any entity registered with the Commission to sell electricity to retail Customers in New Hampshire.

EDI Working Group Report: The report submitted by the Electronic Data Interchange Working Group to the Commission on April 2, 1998, and approved by Order 22,919. The report is available on the Commission's website.

Energy Service: The sale of electricity, including ancillary services such as, but not limited to, the provision of reserves, to a Customer by a Competitive Supplier.

ISO-NE: ISO New England Inc., authorized by the Federal Energy Regulatory Commission to exercise for New England the functions required pursuant to the Commission's Order No. 2000 (and its progeny) and the Commission's regulations, and any successor organization (including but not limited to a Regional Transmission Organization).

Market Participant: A participant in the New England Market that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the FERC.

NEPOOL: New England Power Pool and its successors.

NEPOOL Agreement: The Second Restated New England Power Pool Agreement dated as of February 1, 2005, as amended or accepted by the Commission and as may be amended, modified, superseded, supplemented and/or restated from time to time.

PTF: Pool transmission facilities included in the Open Access Transmission Tariff on file with the Federal Energy Regulatory Commission and any successor agreements.

Settlement Account: The settlement method (and any successor settlement methodologies) utilized by ISO-NE for its Market Participants, as set forth in the ISO-NE Transmission, Markets and Services Tariff, as amended from time to time, on file as a tariff with the Federal Energy Regulatory Commission.

iii. Obligation of Parties

Customer shall select one Competitive Supplier for each account at any given time for the purposes of the Company (1) reporting the Customer's hourly electric consumption to the ISO-NE, and (2) providing billing services. The Customer must provide the selected Competitive Supplier with the information necessary to allow the Competitive Supplier to initiate Energy Service, as required by the Competitive Supplier. A Customer may choose only a Competitive Supplier that is registered by the Commission.

1. The Company shall:

    a) Arrange for or provide local network transmission services from PTF to the Company's distribution system for each Customer;
    b) Arrange for or provide regional network transmission service over PTF ;
    c) Be responsible for obtaining and maintaining Regional Transmission Service (or its successor);
    d) Be responsible for the Network Load (as defined in the ISO-NE Transmission, Markets and Services Tariff) associated with its retail customers located in the Company's service area;
    e) Deliver power over distribution facilities to each Customer Delivery Point;
    f) Provide customer service and support for Distribution Service;
    g) Respond to service interruptions or power quality problems;

h) Handle connections and terminations;
i) Read Meters;
j) Submit bills to Customers for Distribution Service and, if requested by the Competitive Supplier, for Energy Service;
k) Address billing inquiries for Distribution Service and, if contracted by the Competitive Supplier, for Energy Service;
l) Answer general questions about Distribution Service;
m) Report Competitive Suppliers' estimated and metered loads, including local network transmission and distribution losses, to the ISO-NE,
n) Process the electronic business transactions submitted by Competitive Suppliers, and send the necessary electronic business transactions to Competitive Suppliers, below, and the rules and procedures set forth in the EDI Working Group Report;
o) Provide information regarding, at a minimum, tariffs, meter read schedules, and load profiles, on its Internet web site; and
p) Provide up to twelve months of a Customer's historic billing data to a Customer or a Competitive Supplier, provided that the Competitive Supplier has received the appropriate authorization, this information shall be provided in electronic form at no charge.

2. The Competitive Supplier shall:

a) Meet the registration and licensing requirements established by law or regulation and either (i) be a Market Participant subject to a Settlement Account or (ii) have an agreement in place with a Market Participant whereby the Market Participant agrees to include the load to be served by the Competitive Supplier in such Market Participant's Settlement Account;
b) Be responsible for providing all requirements service to meet each of its Customer's needs and deliver the associated capacity and energy to a point or points of local network interface between the PTF and non-PTF systems;
c) Give the Company at least 60 days' prior notice of termination of its status as a Market Participant or termination of the agreement referenced in Section 2.e. below. The Competitive Suppliers right to serve customers will cease effective with such termination, however the supplier will continue to be obligated to settle all financial obligations with the Company which were incurred prior to such termination;
d) Be responsible for any and all losses incurred on (i) local network transmission systems and distribution systems, as determined by the Company; (ii) PTF, as determined by the ISO-NE; and (iii) facilities linking generation to PTF;
e) Enter into a CEPS Agreement with the Company that specifies, among other things, information exchange, problem resolution, and revenue liability. This agreement must be entered into prior to the initiation of Energy Service to any Customer in the Company's service territory. A business initiation fee of $500.00 will be charged to each Competitive Supplier. This fee includes the costs of EDI connectivity and initial set up

of the Competitive Supplier in the Company's system. Charges for additional services that may be required will be negotiated with each Competitive Supplier and included in the CEPS Agreement;

f) Complete testing of the transactions included in the EDI Working Group Report prior to the initiation of Energy Service to any Customer in the Company's service territory. Such testing shall be in accordance with the rules and procedures set forth in the Report;

g) Be responsible for obtaining the necessary authorization from each Customer prior to initiating Energy Service to the Customer;

h) Be responsible for obtaining the necessary authorization from each Customer prior to requesting the Company to release the historic usage information or Interval Data specific to that Customer to the Competitive Supplier. Such authorization shall consist of (i) a letter of authorization; (ii) electronic transmission to a competitive supplier; or (iii) a written authorization provided to a registered Aggregator.

iv. Provisions of Service

1. Initiation of Energy Service

a) To initiate Energy Service to a Customer, the Competitive Supplier shall submit an "enroll customer" transaction to the Company, in accordance with the rules and procedures set forth in the EDI Working Group Report. The Competitive Supplier shall hold the "enroll customer" transaction until any applicable right of rescission has lapsed.

b) If the information on the enrollment transaction is correct, the Company shall send the Competitive Supplier a "successful enrollment" transaction, in accordance with the rules and procedures set forth in the EDI Working Group Report.

c) Energy Service shall commence on the date of the Customer's next scheduled meter read, provided that the Supplier has submitted the enrollment transaction to the Distribution Company no fewer than two (2) business days prior to the next meter read date.

d) If the Supplier has not submitted the enrollment transaction at least two (2) business days before the next meter read date, Energy Service shall commence on the date of the Customer's subsequent scheduled meter read.

e) If more than one Competitive Supplier submits an enrollment transaction for a given Customer during the same enrollment period, the first transaction that is received by the Distribution Company shall be accepted. All other transactions shall be rejected. Rejected transactions may be resubmitted during the customer's next enrollment period.

2. Termination of Energy Service

a) To terminate Energy Service with a Customer, a Competitive Supplier shall submit a "supplier drops customer" transaction, in accordance with the rules and procedures set forth in the EDI Working Group Report. Energy Service shall be terminated on the date of the customer's next scheduled meter read, provided that the Competitive Supplier has submitted this transaction to the Distribution Company no fewer than two

(2) business days prior to the meter read date. If the Competitive Supplier has not submitted this transaction at least two (2) business days before the meter read date, Energy Service shall be terminated on the date of the Customer's subsequent meter read. The Distribution Company shall send a "confirm drop date" transaction to the Competitive Supplier, in accordance with the rules and procedures set forth in the EDI Working Group Report.

b) To terminate Energy Service with a Competitive Supplier, a Customer shall so inform the Competitive Supplier who will submit the required "supplier drops customer" transaction. Energy Service shall be terminated on the date of the Customer's next scheduled meter read.

c) In those instances when a Customer, who is receiving Energy Service from an existing Competitive Supplier, initiates such service with a new Competitive Supplier, the new Competitive Supplier must submit an EDI enrollment request to the Company. The Company shall send the existing Competitive Supplier a "customer drops supplier" transaction, in accordance with the rules and procedures set forth in the EDI Working Group Report.

d) In cases where the Company uses estimated energy and demand values for billing purposes and the estimated bill coincides with the termination of Supplier Service, the Supplier shall agree to accept the estimated metering values as final values. The Company shall not be obligated to reconcile the estimated values after actual meter reading values are available. Reconciliations of actual meter reads will be at the discretion of the Company.

3. Customer Outages

a) Planned Outages

In the event that the loading on the distribution system, or a portion thereof, must be reduced for safe and reliable operation, such reduction in loading shall be proportionately allocated among all Customers whose load contributes to the need for the reduction, when such proportional curtailments can be accommodated within good utility practices.

b) Unplanned Outages

In the event of unplanned outages, service will be restored in accordance with good utility practice. The Company may also be called upon from time to time by ISO New England to implement voltage reductions or load shed procedures to protect the security of the bulk power grid. The Company shall not be liable for any revenue losses to the Competitive Supplier as a result of any such disconnection(s).

4. Metering

a) Meter Reading

The Company shall meter each Customer in accordance with tariff provisions.

Each Customer shall be metered or estimated such that the loads can be reported to ISO-NE for inclusion in the Competitive Supplier's, or the Competitive Supplier's wholesale provider's Settlement Account.

b) Ownership of Metering Equipment

Should a Customer or Competitive Supplier request a metering device outside of the Company's current metering equipment or request that a communication device be attached to the existing meter, the Company shall provide, install, test, and maintain the requested metering or communication device. The requested meter or communication device must meet the Company's requirements.

The Customer or Competitive Supplier shall bear the cost of providing and installing the meter or communication device. Upon installation, the meter or communication device shall become the property of the Company and will be maintained by the Company. The Company shall complete installation of the meter or communication device, if reasonably possible, within thirty (30) days of receiving a written request from the Customer or Competitive Supplier. The Company shall bill the Customer or Competitive Supplier upon installation.

5. Billing Service

The Company shall provide a single bill, reflecting unbundled charges for electric service, to Customers who receive Energy Service. The Company shall offer two billing service options to Competitive Suppliers providing Energy Service to Customers: a) Standard Billing Service; and b) Consolidated Billing Service. The Competitive Supplier shall inform the Company of the selected billing option, in accordance with the rules and procedures set forth in the EDI Working Group Report.

c) Standard Billing Service

The Company shall issue a single bill for Distribution Service to each Customer. The Competitive Supplier shall be responsible for separately billing Customers for the cost of Energy Service provided by the Competitive Supplier and for the collection of amounts due to the Competitive Supplier from the Customer.

The Company shall send a "customer usage information" transaction to the Competitive Supplier, in accordance with the rules and procedures set forth in the EDI Working Group Report.

b) Consolidated Billing Service

The Company shall issue a single unbundled bill for electric service to each Customer.

The Company shall use the rates supplied by the Competitive Supplier to calculate the Competitive Supplier's portion of a Customer's bill, and integrate this billing with its own billing in a single mailing to the Customer.
The Company shall send a "customer usage and billing information" transaction to the Competitive Supplier, in accordance with the rules and procedures set forth in the EDI Working Group Report.

6. Payment Services

Upon receipt of Customer payments, the Company shall send a "payment/ adjustment" transaction to the Competitive Supplier, in accordance with the rules and procedures set forth in the EDI Working Group Report. Customer revenue due the Competitive Supplier shall be transferred to the Competitive Supplier in accordance with the CEPS agreement entered into by the Competitive Supplier and the Company.

The following payment allocation between the Company and Competitive Suppliers shall apply if a Customer pays the Company less than the full amount billed:

a) Any outstanding customer loans or deposit obligations with the Company;
b) Any Company current payment arrangement obligations;
c) Any Company budget billing arrangement obligations;
d) Company and Supplier aged accounts receivables, with a priority for the Company's aged receivables;
e) Company and Supplier current charges, with a priority for the Company's current charges; and
f) Any Company miscellaneous non-electric service product or services.

Any services in addition to initial set up, that requires the use of the Company's external EDI vendor, will be charged to the supplier a per-hour rate.

Business Initiation Fee	$500.00 one-time fee
Payment Service Customization	$175.00 per hour

Existing Company service fees, such as interest charges for unpaid balances and bad checks charges, shall remain in effect and shall be assessed, as applicable, according to the Company's Terms and Conditions for Distribution Service, applicable to all Customers.

v. Definition of Standard Units of Service

6. Billing Demand

Units of billing demand shall be as defined in the Company's applicable Rate Schedule.

7. On-Peak / Off-Peak Period Definitions

The on-peak and off-peak periods shall be as defined in the Company's applicable Rate Schedule.

vi. Determination of Hourly Loads

1. For each Competitive Supplier, hourly loads for each day shall be estimated or telemetered, and reported daily to the ISO-NE for inclusion in the Competitive Supplier's Settlement Account. Hourly load estimates for non-telemetered customers will be based upon load profiles developed for each customer class or Customer of the Company. The total hourly loads will be determined in accordance with the appropriate hourly load for the Company.

2. The Company shall normally report previous days' hourly loads to the ISO-NE by a specified time. These loads shall be included in the Competitive Supplier's Settlement Account.

3. To refine the estimates of the Competitive Suppliers' loads that result from the estimated hourly loads, a monthly calculation shall be performed to incorporate the most recent customer usage information, which is available after the monthly meter readings are processed.

4. The hourly loads shall be determined consistent with the following steps:
   a) The Company shall identify or develop a load profile for each customer class or each Customer for use in each day's daily determination of hourly load.
   b) The Company shall calculate a usage factor for each Customer that reflects the Customer's relative usage level.
   c) The Company shall develop estimates of hourly load profiles for the previous days for each Competitive Supplier such that the sum of the Competitive Suppliers' loads equals the hourly metered loads collected each day. Distribution losses, which are included in the hourly metered Company loads, shall be fully allocated into Competitive Supplier loads.

d) Transmission losses from local network facilities shall be approximated and added to the Competitive Supplier's hourly loads.

5. The process of Competitive Supplier load estimation involves statistical samples and estimating error. The Company shall not be responsible for any estimating errors and shall not be liable to the Competitive Suppliers for any costs that are associated with such estimating errors.

63. Residential Energy Efficiency Loan Program

i. Availability

Subject to the Terms and Conditions of the Tariff of which it is a part, this program shall allow Customers installing energy-efficiency measures under an energy efficiency program offered by the Company and approved by the Commission ("Participating Customers") to borrow all or a portion of the Customer's share of the installed cost of the energy-efficiency measures ("Customer Loan Amount") from the Company and to repay the Customer Loan Amount through an additional charge on their monthly retail delivery service bill issued by the Company. It is available to Participating Customers who meet the following qualifications:

1. The Participating Customer must own the property where the energy-efficiency measures are installed; and

2. A Participating Customer must have an active Delivery Service account with the Company for the property where the energy-efficiency measures are installed and receive Delivery Service under Domestic Rate D, Optional Peak Load Pricing Rate D-10, or Limited Total Electric Living Rate T; and

3. The Participating Customer must not have received a disconnect notice from the Company during the twelve months preceding the Participating Customer's request for a loan under this program; and

4. The Customer Loan Amount has no minimum and must be less than or equal to $2,000 per customer per year, and must not exceed the Participating Customer's share of the installed cost of the energy efficiency measures installed under the Company's approved energy-efficiency program; and

5. The Participating Customer must meet the qualifications of the applicable energy-efficiency program through which the energy-efficiency measures are being installed.

At its sole discretion, the Company shall determine eligibility for service under this program subject to the availability of program funds.

Any Participating Customer receiving a loan under this program must remain a Delivery Service customer of the Company at the property where the energy-efficiency measures are installed until the loan has been repaid in full. In the event the Participating Customer ceases to be a Delivery Service Customer of the Company at the property where the energy-efficiency measures are installed, any remaining charges under this program shall immediately become due and payable.

ii. Customer Loan Agreement

Participating Customers shall be required to execute a separate Residential Customer Loan Agreement which will specify the fixed monthly charge and other applicable terms. A Participating Customer can choose to pay the remaining balance owed to the Company at any time. A late payment charge as described in the Terms and Conditions for Delivery Service section of the Company's Tariff is applicable to the monthly charges rendered under this program. Participating Customers are not subject to disconnection of electric service for nonpayment of the charges under this program.

The Customer Loan Amount shall be paid to the Company by the Participating Customer through a fixed monthly charge applied over a term of months as established in the Customer Loan Agreement. Participating Customers may specify the repayment term of the Customer Loan Amount subject to the maximum repayment term limit of 24 months. The revolving loan fund is funded through a grant from the Greenhouse Gas Emissions Reduction Fund created pursuant to RSA 125-O:23 as administered by the Commission.

64. Non-Residential Energy Efficiency Loan Program

i. Availability

Subject to the Terms and Conditions of the Tariff of which it is a part, this program shall allow Customers installing energy-efficiency measures under an energy efficiency program offered by the Company and approved by the Commission ("Participating Customers") to borrow all or a portion of the Customer's share of the installed cost of the energy-efficiency measures ("Customer Loan Amount") from the Company and to repay the Customer Loan Amount through an additional charge on their monthly retail delivery service bill issued by the Company. It is available to Participating Customers who meet the following qualifications:

1. The Participating Customer must own the property where the energy-efficiency measures are installed; and

2. A Participating Customer must have an active Delivery Service account with the Company for the property where the energy-efficiency measures are installed and receive Delivery Service under General Service Time-of-Use Rate G-1, General Long-Hour Service Rate G-2, General Service Rate G-3, or Outdoor Lighting Service Rate M, LED-1 and LED-2; and

3. The Participating Customer must not have received a disconnect notice from the Company during the twelve months preceding the Participating Customer's request for service under this program; and

4. The Customer Loan Amount has no minimum and must be less than or equal to $50,000 for each project, and must not exceed the Participating Customer's share of the installed cost of the energy efficiency measures installed under the Company's approved energy-efficiency program; and

5. A Participating Customer is limited to $150,000 per year in loan funds with no limit on the number of projects at the sole discretion of the Company based on program demand. If at any point there are no loan fund recipients or there have been no loan fund recipients in a given year, the Company may petition the Commission to allow a particular customer to receive more than $150,000 in loan funds in a given year; and

6. The Participating Customer must meet the qualifications of the applicable energy-efficiency program through which the energy-efficiency measures are being installed.

At its sole discretion, the Company shall determine eligibility for service under this program subject to the availability of program funds.

Any Participating Customer receiving a loan under this program must remain a Delivery Service customer of the Company at the property where the energy-efficiency measures are installed until the loan has been repaid in full. In the event the Participating Customer ceases to be a Delivery Service Customer of the Company at the property where the energy-efficiency measures are installed, any remaining charges under this program shall immediately become due and payable.

ii. Customer Loan Agreement

Participating Customers shall be required to execute a separate Non-Residential Customer Loan Agreement which will specify the fixed monthly charge and other terms of the loan. A Participating Customer can choose to pay the remaining balance owed to the Company at any time. A late payment charge as described in the Terms and Conditions for Delivery Service section of the Company's Tariff is applicable to the monthly charges rendered under this program. Participating Customers are not subject to disconnection of electric service for nonpayment of the charges under this program.

The Customer Loan Amount shall be paid to the Company by the Participating Customer through a fixed monthly charge applied over a term of months as established in the Customer Loan Agreement. Participating Customers may specify the repayment term of the Customer Loan Amount subject to the maximum repayment term limit of 120 months.

The revolving loan fund is funded through a grant from the Greenhouse Gas Emissions Reduction Fund created pursuant to RSA 125-O:23 as administered by the Commission.

Rate D

Availability

Retail Delivery Service under this rate is available for all domestic purposes in an individual private dwelling or an individual apartment and for farm purposes. If electricity is delivered through more than one meter, the charge for electricity delivered through each meter shall be computed separately under this rate.

Character of Service

Service supplied under this rate will be single phase, 60 cycle, alternating current, normally three-wire service at a nominal voltage of 120/240 volts or three-wire 120/208 volts, whichever is available at the location.

Rate Per Month

The rate per month will be the sum of the applicable Customer and Energy Charges subject to the adjustments in this tariff:

Rates for Retail Delivery Service

Customer Charge $14.74 per month

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge All kWh	5.480
Reliability Enhancement/Vegetation Management	0.008
Total Distribution All kWh	5.488
Transmission Charge	2.660
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

Off-Peak Use: 16 Hour Control

For all electricity separately metered and delivered between the hours of 11:00 p.m. on each day and 7:00 a.m. on the next day, the price of such electricity shall be:

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge Off Peak Use	4.732
Reliability Enhancement/Vegetation Management	0.008
Total Distribution	4.740
Transmission Charge	2.660
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

If a Customer has installed an electric water heater of a type approved by the Company, electricity is delivered to such water heater is supplied only under this rate.

Off-Peak Use: 6 Hour Control

For all electricity separately metered and subject to the Company's right to limit the operation of the bottom water heating element up to 6 hours a day, the price of such electricity shall be:

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge Off Peak Use	4.819
Reliability Enhancement/Vegetation Management	0.008
Total Distribution	4.827
Transmission Charge	2.660
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

If a Customer has installed an electric water heater of a type approved by the Company, and electricity delivered to such water heater is supplied only under this rate

Farm Use

The availability of the Farm Use Section is limited to those locations which were served under the Farm Use Section of Domestic Rate D, N.H.P.U.C. No. 8 - Electricity immediately prior to the effective date of this rate. For such farm customers, where all electricity is supplied by the Company, the RATE PER MONTH is modified as follows:

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge*	5.173
Reliability Enhancement/Vegetation Management	0.008
Total Distribution	5.181
Transmission Service Cost Adjustment	2.660
Stranded Cost Adjustment Factor	(0.072)
Storm Recovery Adjustment Factor	0.000

*All Regular Use kilowatt-hours in excess of the greater of the following:

i. 500 kilowatt-hours
ii. 100 kilowatt-hours per kilovolt-ampere of transformer capacity needed to serve the Customer

Rate D-10 Optional Peak Load Rate

Availability

Retail Delivery Service under this rate is available for all domestic purposes in an individual private dwelling or an individual apartment and for farm purposes to selected customers presently served under Rate D.

If electricity is delivered through more than one meter, the charge for electricity delivered through each meter shall be computed separately under this rate. The availability of this rate will be subject to the Company's ability to obtain the necessary meters and to render such service.

Character of Service

Service supplied under this rate will be single phase, 60 cycle, alternating current, normally three-wire service at a nominal voltage of 120/240 volts or three-wire 120/208 volts, whichever is available at the location.

Rate Per Month

The rate per month will be the sum of the applicable Customer and Energy Charges subject to the adjustments in this tariff:

Rates for Retail Delivery Service

Customer Charge	$14.74 per month

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge On Peak	11.694
Distribution Charge Off Peak	0.159
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge On Peak	11.702
Total Distribution Charge Off Peak	0.167
Transmission Charge	2.269
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

Peak hours will be from 8:00 a.m. to 9:00 p.m. daily on Monday through Friday excluding holidays.

Off-Peak hours will be from 9:00 p.m. to 8:00 a.m. daily Monday through Friday, and all day on Saturdays, Sundays, and holidays.

Electric water heating service is available under this rate subject to the conditions specified herein. For such water heating service the Company will provide, own and maintain a suitable switch designed to control the operation of the water heater so that the bottom heating element may operate only during Off-Peak hours.

Electric Water Heating Conditions

Electricity delivered to the water heater must be separately controlled. The Company shall install, own and maintain the control relay. The bottom water heating element will operate only during Off-Peak hours. All water heaters installed after the effective date of this rate shall have a storage capacity of 80 gallons or greater and be of a type approved by the Company. However, approved water heater of less than 80 gallons now being served by the Company may be permitted to transfer to this rate, and at the Company's option smaller tanks may be permitted only within an individual apartment of a multi-family building.

Terms of Agreement

The agreement for service under this rate will continue for an initial term of one year if electricity can be properly delivered to a Customer without an uneconomic expenditure by the Company. The agreement may be terminated at any time on or after the expiration date of the initial term by twelve (12) months prior written notice.

General Service Time-of-Use Rate G-1

Availability

Retail Delivery Service under this rate is available for all purposes except resale, subject to the provisions of this section. The sale of electric vehicle charging services to a third party from an electric vehicle charging station shall not be considered resale of electricity. A Customer will take delivery service on this rate if the Company estimates that its average use will be greater than or equal to 200 kW of Demand. A Customer may be transferred from rate G-1 at its request or at the option of the Company if the customer's 12 month average monthly demand is less than 180 kW of Demand for 3 consecutive months.

If electricity is delivered through more than one meter, except at the Company's option, the charge for electricity delivered through each meter shall be computed separately under this rate. If any electricity is delivered hereunder at a given location, then all electricity delivered by the Company at such location shall be furnished hereunder, except such electricity as may be delivered under the provisions of the Limited Commercial Space Heating Rate V.

The actual delivery of service and the rendering of bills under this rate is contingent upon the installation of the necessary time-of-use metering equipment by the Company; subject to both the availability of such meters from the Company's supplier and the conversion or installation procedures established by the Company.

All customers served on this rate must elect to take their total electric service under the time-of-use metering installation as approved by the Company. If delivery is through more than one meter, except at the Company's option, the Monthly Charge for service through each meter shall be computed separately under this rate.

Character of Service

Service supplied under this rate will be 60 cycle, three-phase alternating current normally at a nominal voltage of 120/208, 277/480, 2400, 4160, 4800, 7200, 13,200 and 13,800 volts.

All voltages are not available in every area.

Rate Per Month

The Rate Per Month will be the sum of the applicable Customer, Demand and Energy Charges subject to the adjustments in this tariff.

Rates for Retail Delivery Service

Customer Charge	$414.69 per month
Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)	
Distribution Charge On Peak	0.564
Distribution Charge Off Peak	0.168
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge On Peak	0.572
Total Distribution Charge Off Peak	0.176
Transmission Charge	2.065
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

Demand Charges Per Kilowatt

Distribution	$8.81

Distribution Energy Charges Peak Periods

Peak hours will be from 8:00 a.m. to 9:00 p.m. daily on Monday through Friday excluding holidays.

Off-Peak hours will be from 9:00 p.m. to 8:00 a.m. daily Monday through Friday, and all day on Saturdays, Sundays, and holidays.

Demand

The Demand for each month under ordinary load conditions shall be the greatest of the following:

1. The greatest fifteen-minute peak during the peak hours which occurs during such month as measured in kilowatts,
2. 90% of the greatest fifteen-minute peak during the peak hours occurring during such month as measured in kilovolt-amperes where the Customer's kilowatt Demand exceeds 75 kilowatts, or
3. 80% of the greatest Demand as so determined above during the preceding eleven months.

Any Demands established during the eleven (11) months prior to the application of this rate shall be considered as having been established under this rate.

Issued:	XX XX, 20XX	Issued by:	/s/ Susan L. Fleck Susan L. Fleck
Effective:	XX XX, 20XX	Title:	President

Optional Determination of Demand

However, a Customer who has been served hereunder for one year or more may upon written request have the Demand for each month, beginning with the next month after such request and running for a period of not less than two consecutive months, be based upon the greatest of items a) or b) above. In such case, the Demand Charge and the Energy Charge will be increased by 20% during such period.

High Voltage Metering Adjustment

The Company reserves the right to determine the metering installation. Where service is metered at the Company's supply line voltage, in no case less than 2400 volts, thereby saving the Company transformer losses, a discount of 1% will be allowed from the amount determined under the preceding provisions.

Credit for High Voltage Delivery

If the Customer accepts delivery at the Company's supply line voltage, not less than 2400 volts and the Company is saved the cost of installing any transformer and associated equipment, a credit of billing demand for such month shall be allowed against the amount determined under the preceding provisions.

High Voltage Delivery Credit ($0.47) per kW

Terms of Agreement

A Customer served under this rate must provide the Company with one-year prior written notice before installing additional on-site, non-emergency generation for its own use. This notice provision shall be waived with respect to the installation of on-site non-emergency generation from renewable energy resources. Renewable energy resources shall mean fuel cells (including natural gas powered fuel cells), and emerging power technologies that produce electricity from wind energy, solar energy, small-scale hydro power, ocean power, landfill gas, sustainably managed biomass, and future clean renewable technologies.

General Long Hour Service Rate G-2

Availability

Retail Delivery Service under this rate is available for all purposes except resale subject to the provisions of this section. The sale of electric vehicle charging services to a third party from an electric vehicle charging station shall not be considered resale of electricity. A Customer will take delivery service on this rate if the Company estimates that its average use will be greater than or equal to 20 kW of Demand but is less than 200 kW of Demand. If electricity is delivered through more than one meter, except at the Company's option, the charge for electricity delivered through each meter shall be computed separately under this rate. A customer may be transferred from rate G-2 at its request or at the option of the Company if the customer's twelve (12) month average monthly demand is less than 18 kW of demand for three consecutive months.

If any electricity is delivered hereunder at a given location, then all electricity delivered by the Company at such location shall be furnished hereunder, except such electricity as may be delivered under the provisions of the Limited Commercial Space Heating Rate V.

Character of Service

Service supplied under this rate will be 60 cycle, three-phase alternating current normally at a nominal voltage of 120/208, 277/480, 2400, 4160, 4800, 7200, 13,200 and 13,800 volts.
All voltages are not available in every area.

Rate Per Month

The Rate Per Month will be the sum of the applicable Customer, Demand and Energy Charges subject to the adjustments in this tariff.

Rates for Retail Delivery Service

Customer Charge $69.13 per month

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge	0.224
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge	0.232

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Susan L. Fleck
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Transmission Charge	2.553
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

Demand Charges Per Kilowatt

Distribution	$8.86

Demand

The Demand for each month under ordinary load conditions shall be the greatest of the following:

1. The greatest fifteen-minute peak during the peak hours which occurs during such month as measured in kilowatts,
2. 90% of the greatest fifteen-minute peak occurring during such month as measured in kilovolt-amperes where the Customer's kilowatt Demand exceeds 75 kilowatts, or
3. 80% of the greatest Demand as so determined above during the preceding eleven months.

Any Demands established during the eleven months prior to the application of this rate shall be considered as having been established under this rate.

Optional Determination of Demand

However, a Customer who has been served hereunder for one year or more may upon written request have the Demand for each month, beginning with the next month after such request and running for a period of not less than two consecutive months, be based upon the greatest of items a) or b) above. In such case, the Demand Charge and the Energy Charge will be increased by 20% during such period.

High Voltage Metering Adjustment

The Company reserves the right to determine the metering installation. Where service is metered at the Company's supply line voltage, in no case less than 2400 volts, thereby saving the Company transformer losses, a discount of 1% will be allowed from the amount determined under the preceding provisions.

Credit for High Voltage Delivery

If the Customer accepts delivery at the Company's supply line voltage, not less than 2400 volts, and the Company is saved the cost of installing any transformer and associated equipment, a credit of the peak hours billing demand for such month shall be allowed against the amount determined under the preceding provisions.

High Voltage Delivery Credit	($0.47) per kW

Terms of Agreement

A Customer served under this rate must provide the Company with one-year prior written notice before installing additional on-site, non-emergency generation for its own use. This notice provision shall be waived with respect to the installation of on-site non-emergency generation from renewable energy resources. Renewable energy resources shall mean fuel cells (including natural gas powered fuel cells), and emerging power technologies that produce electricity from wind energy, solar energy, small-scale hydro power, ocean power, landfill gas, sustainably managed biomass, and future clean renewable technologies.

General Service Rate G-3

Availability

Retail Delivery Service under this rate is available for all purposes except resale. The sale of electric vehicle charging services to a third party from an electric vehicle charging station shall not be considered resale of electricity. A Customer will take delivery service on this rate if the Company estimates that its average use will be less than 20 kW of demand. If electricity is delivered through more than one meter, except at the Company's option, the charge for electricity delivered through each meter shall be computed separately under this rate.

Character of Service

Service supplied under this rate will be 60 cycle, alternating current either:

a) Single-phase normally three-wire at a nominal voltage of 120/240 volts.
b) Three-phase secondary normally at a nominal voltage of 120/208, or 277/480 volts.
c) Three-phase primary normally at a nominal voltage of 2400, 4160, 4800, 7200, 13,200 or 13,800 volts.

All voltages are not available in every area.

Rate Per Month

The rate per month will be the sum of the Customer and Energy Charges subject to the adjustments in this tariff:

Rates for Retail Delivery Service

Customer Charge $15.90 per month

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge	5.036
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge	5.044
Transmission Charge	2.550
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

Terms of Agreement

A Customer served under this rate must provide the Company with one-year prior written notice before installing additional on-site, non-emergency generation for its own use. This notice provision shall be waived with respect to the installation of on-site non-emergency generation from renewable energy resources. Renewable energy resources shall mean fuel cells (including natural gas powered fuel cells), and emerging power generation technologies that produce electricity from wind energy, solar energy, small-scale hydro power, ocean power, landfill gas, sustainably managed biomass, and future clean renewable technologies.

Reliability Enhancement Program and Vegetation Management Plan Adjustment

All energy billed under this rate is subject to a Reliability Enhancement Program and Vegetation Management Plan Adjustment Factor which shall be adjusted from time to time.

Reliability Enhancement Program Capital Investment Allowance

Distribution base rates are subject to adjustment on an annual basis for a Reliability Enhancement Program Capital Investment Allowance.

Limited Total Electrical Living Rate T

Availability

The availability of this rate is limited to the following customers: 1) those who immediately prior to the effective date of this rate were served under Total Electric Living Rate T, NHPUC No. 8 - Electricity and are presently receiving service under this rate, and (2) those who requested service under this rate prior to May 1, 1982.

To such customers, delivery service under this Limited Total Electric Living Rate T continues to be available to the classifications below, subject to the conditions hereinafter stated:

Classifications

1. An individual residence or individual apartment.

2. A building or group of buildings under common ownership and operation, where the principal use of electricity is for living quarters. If the owner does not furnish all the electric requirements to the residential tenants of a building, the balance of these residential requirements may be billed individually to the tenants under this rate.

3. A church or school, including adjacent buildings owned and operated by such church or school and used principally for religious or education purposes.

Conditions

1. Electricity must be the sole source of energy for space heating and water heating.

2. All electrical space heating equipment must be permanently installed. It is recommended that insulation be permanently installed and conform to the Company's standards.

3. All water heaters installed shall be of a type and size approved by the Company.

4. The Customer shall provide a separate circuit for the water heater, of ample capacity and designed for a 240-volt operation, to which no equipment other than the water heater shall be connected.

Character of Service

Service supplied under this rate will be single phase, 60 cycle, alternating current, normally three-wire service at a nominal voltage of 120/240 volts or three-wire 120/208 volts, whichever is available at the location.

Rate Per Month

The rate per month will be the sum of the applicable Customer and Energy Charges subject to the adjustments in this tariff.

Rates for Retail Delivery Service

Customer Charge $14.74 per month

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge	4.469
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge	4.477
Transmission Charge	2.620
Stranded Cost Charge	(0.073)
Storm Recovery Adjustment Factor	0.000

Terms of Agreement

A Customer served under this rate must provide the Company with one-year prior written notice before installing additional generation for its own use. This notice provision shall be waived with respect to the installation of on-site non-emergency generation from renewable energy resources. Renewable energy resources shall mean fuel cells (including natural gas powered fuel cells), and emerging power generation technologies that produce electricity from wind energy, solar energy, small-scale hydro power, ocean power, landfill gas, sustainably managed biomass, and future clean renewable technologies.

Unmetered Electric Service Rate U

Unmetered services are usually not permitted. However, if after careful study it definitely appears the installation of a meter is impractical, due to the design of the Customer's equipment, then the Customer’s monthly bill will be computed by applying the applicable electric rate schedule to a use arrived at by multiplying the total load by 730 hours.

This policy will not be applied when the load is controlled by the Company through a street lighting circuit, nor does it apply to traffic signals owned and controlled by Municipalities.

Limited Commercial Space Heating Rate V

Availability

The availability of this rate is limited to the following customers: 1) those who immediately prior to the effective date of this rate were served under Commercial Space Heating Rate V, NHPUC No. 8 - Electricity and are presently receiving service under this rate, and 2) those who requested service under this rate prior to May 1, 1982.

To such customers, delivery service under this Limited Commercial Space Heating Rate V is available for space heating in buildings other than residences, where the Customer's premises are heated exclusively by electricity.

Air conditioning used in addition to electric space heating at this same location may also be served under this rate, provided that electricity is the sole source of energy, and all the requirements for these purposes are metered hereunder.

Electric space heating equipment shall be permanently installed and be of a type and size approved by the Company.

Service under this rate will be metered separately.

Any other use of electricity must be taken under an applicable general service rate.

This rate is not available for resale or auxiliary service.

Character of Service

Service supplied under this rate will be single phase, 60 cycle, alternating current, normally three-wire service at a nominal voltage of 120/240 volts or three-wire 120/208 volts, whichever is available at the location, or other voltages where available by special arrangement with the Company.

Rate Per Month

The rate per month will be the sum of the applicable Customer and Energy Charges subject to the adjustments in this tariff.

Rates for Retail Delivery Service

Customer Charge	$15.90 per month

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge	5.179
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge	5.187
Transmission Charge	2.501
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

Terms of Agreement

A Customer served under this rate must provide the Company with one-year prior written notice before installing additional on-site, non-emergency generation for its own use. This notice provision shall be waived with respect to the installation of on-site non-emergency generation from renewable energy resources. Renewable energy resources shall mean fuel cells (including natural gas powered fuel cells), and emerging power generation technologies that produce electricity from wind energy, solar energy, small-scale hydro power, ocean power, landfill gas, sustainably managed biomass, and future clean renewable technologies.

Outdoor Lighting Service Rate M

Availability

Public Lighting

Available for Street or Highways and areas within the public domain for customers designated as governmental entities, inclusive of the state, municipalities, or other public authorities.
Installations on limited access highways, tunnels, bridges and the access and egress ramps thereto are subject to the Special Rate Conditions of this tariff.

Private Lighting

Available to private customers for outdoor lighting of areas on private property where necessary fixtures can be supported on existing poles and where such service can be supplied from existing secondary distribution facilities.
In special circumstances outlined in the pole and accessory section below, the Company will install a wooden pole.

Lighting Services

Service under this rate is for full-night service street lighting whereby the luminaire operates for the entire night time period pursuant to the Hours of Operation provision below. In addition, customers may, at their option, take advantage of part-night service in which the luminaire operates for a portion of the night pursuant to the Hours of Operation provision below. Customers may select the part-night service option at the time of lighting installation or at any time during service. Any request to select the part-time night service option must be made in writing.

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge	3.873
Reliability Enhancement/Vegetation Management	0.008
Total Distribution	3.881
Transmission Charge	1.520
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

No further installation or relocation of Incandescent and Mercury Vapor lights will be made after the effective date of this rate.

Pole and Accessory Charge

An additional monthly charge enumerated below will be applied where the Company is requested to furnish a suitable wood pole for the sole purpose of supporting a luminaire. If at a future date the pole is used for any purpose approved by the Company in addition to supporting a street and/or floodlight luminaire, the pole charge will be terminated. This pole may not be more than one (1) span from the existing secondary service located along a roadway or thoroughfare, and must be reachable for mechanized equipment.

Description	**Monthly Price Per Unit**
Overhead Service	
Wood Poles	$9.20
Underground Service – Non-Metallic Standard	
Fiberglass – Direct Embedded	$9.53
Fiberglass with Foundation < 25 ft.	$16.18
Fiberglass with Foundation >= 25 ft.	$27.05
Metal Poles – Direct Embedded	$19.29
Metal Poles with Foundation	$23.26

Other Charges

Pursuant to RSA 9-E:4, the Company provides a part-night service that, when requested by a customer, will require the replacement of the photoelectric control that will allow for the operation of the luminaire for a portion of the night. The Company shall assess the customer a Part Night Charge of $150 for the installation of each photoelectric control that must be replaced in order for part-night service to be operational and for the removal of such photoelectric control upon the customer's request to return to full-night service. For installation or removal of each photoelectric control made during a scheduled maintenance visit or during the installation of a new outdoor lighting service, the Company shall assess the customer a Part Night Charge of $20 for the installation or removal of each such photoelectric control. The Part Night Charge does not include the cost or fees associated with any work-zone protection, traffic control services and/or permits required to perform the customer requested change, all of which shall be the responsibility of the customer.

For Full-Night Schedule and Part-Night Schedule, the monthly distribution charge is based on the monthly cost of the fixture as provided below:

For New and Existing Installations:

Lamp Nominal Light Output	Nominal Power Rating		Monthly Fixed Luminaire Charge	Average Monthly kWh		Monthly kWh Charges		Total Distribution Charges	
				Full Night Schedule	Part-Night Schedule	Full Night Schedule	Part-Night Schedule	Full Night Schedule	Part-Night Schedule
(Lumens)	Watts	Kelvin	$/month	kWh/ month	kWh/ month	$/ month	$/ month	$/ month	$/ month
High Pressure Sodium									
4,000	50	2,000	$8.16	16	8	$0.62	$0.31	$8.78	$8.47
9,600	100	2,000	$9.42	33	17	$1.28	$0.64	$10.70	$10.06
27,500	250	2,000	$15.62	82	41	$3.18	$1.59	$18.80	$17.21
50,000	400	2,000	$19.41	131	66	$5.08	$2.54	$24.49	$21.95
9,600	100	2,000	$11.04	33	17	$1.28	$0.64	$12.32	$11.68
High Pressure Sodium (HPS) Flood									
27,500	250	2,000	$15.78	82	41	$3.18	$1.59	$18.96	$17.37
50,000	400	2,000	$21.08	131	66	$5.08	$2.54	$26.16	$23.62

For Existing Installations Only:

Lamp Nominal Light Output	Nominal Power Rating		Monthly Fixed Luminaire Charge	Average Monthly kWh		Monthly kWh Charges		Total Distribution Charges	
				Full Night Schedule	Part-Night Schedule	Full Night Schedule	Part-Night Schedule	Full Night Schedule	Part-Night Schedule
(Lumens)	Watts	Kelvin	$/month	kWh/ month	kWh/ month	$/ month	$/ month	$/ month	$/ month
Incandescent									
1000	103	2,400	$10.45	34	17	$1.32	$0.66	$11.77	$11.11
Mercury Vapor (MV)									
4,000	100	4,000	$7.23	33	17	$1.28	$0.64	$8.51	$7.87
8,000	175	4,000	$8.13	57	29	$2.21	$1.11	$10.34	$9.24
22,000	400	5,700	$14.51	131	66	$5.08	$2.54	$19.59	$17.05
63,000	1000	4,000	$24.50	328	164	$12.73	$6.36	$37.23	$30.86
Mercury Vapor (MV) Flood									
22,000	400	5,700	$16.60	131	66	$5.08	$2.54	$21.68	$19.14
63,000	1000	4,000	$32.13	328	164	$12.73	$6.36	$44.86	$38.49

Issued: XX XX, 20XX

Effective: XX XX. 20XX

Issued by: /s/ Susan L. Fleck
Susan L. Fleck

Title: President

Limitations on Availability

The availability of this rate to any Customer is contingent upon the availability to the Company of personnel and/or other resources necessary to perform the conversion of existing Fixtures.

Special Rate Conditions

Charges for the operation of outdoor lights may be increased if, in the Company's opinion, lights are to be installed in locations or under conditions such that estimated income will be insufficient to justify the estimated cost of construction.

Billings

One-twelfth of the annual price of luminaires, poles and accessories plus energy charges, including adjustments, will be billed each month beginning with the month following the month in which service is rendered.

Luminaire Charges and Pole and Accessory Charges will be based on the monthly rates above as measured from the date of the prior bill to the current bill date.

Charges per kWh will be based on the monthly kWh per luminaire on page 110.

Hours of Operation

Full-Night Service: All streetlights will be operated every night from approximately one half hour after sunset until approximately one half hour before sunrise, a total of approximately 3,938 hours each year, or approximately 328 average monthly hours.

Part-Night Service: All streetlights will be operated every night from approximately one half hour after sunset then turning off at the earlier of: a time equal to one-half of the Full Night Service period, or five and one-half hours later, a total of no greater than 1,969 hours each year, or approximately 164 average monthly hours.

Failure of Lights to Burn

Should any light fail to burn for the full period provided above, and failure is due to some cause of condition which might reasonably have been prevented by the Company, a deduction will be made from the luminaire price of such light and the kWh for the days the luminaire failed to burn, upon presentation of a claim from the Customer. The deduction shall be equivalent to such part of the annual price thereof as is equal to the ratio that the time of any outage bears to the annual burning time of such light or lights. The provisions of this paragraph do not apply when failure to burn is due to an act of God, or an act or order of any Public Authority or accidental or malicious breakage, provided, however, the necessary repairs are made with reasonable dispatch upon notification by the Customer.

Excessive Damage

Excessive damage to poles, lamps, fixtures, or conductors due to wanton or malicious acts will be charged to the Customer at the actual cost of labor and material required for repair or replace the unit. “Excessive damage” is defined as that which occurs more than once a year. Notification of excessive damage shall be made to the Customer by the Company prior to billing for repairs.

Terms of Service

The customer shall receive and pay for outdoor lighting service for an initial term of five years from the date of installation. Unless notice of termination is given, service shall be extended thereafter for terms of one year. Either the customer or the Company may terminate outdoor lighting service by giving the other written notice at least six months before expiration of a term.

Discontinuance of Lights

Upon expiration of the initial five year term, the Customer may discontinue lights by written notice to the Company. Such discontinuance is contingent upon the customer paying the undepreciated value of the light installation plus a removal charge of $50 per light. Removal of such lights will be completed in a reasonable period as agreed upon.

Conversion of Existing Lights to High Pressure Sodium or LED

Public Street Lights

Incandescent lights - To any municipality or other governmental agency so requesting, the Company will initiate a conversion schedule for the replacement of incandescent lights with an appropriate high pressure sodium light or LED. The conversion will be completed in a period as agreed upon.

Mercury vapor lights - To any municipality or other governmental agency so requesting, the Company will initiate a conversion schedule for the replacement of mercury vapor lights with an appropriate high pressure sodium light or LED upon payment of the undepreciated value of the existing light. This payment may be spread equally over the following twelve month period. The conversion will be completed in a period as agreed upon.

High Pressure Sodium lights - To any municipality or other governmental agency so requesting, the Company will initiate a conversion schedule for the replacement of high pressure sodium lights with an appropriate LED upon payment of the undepreciated value of the existing light. This payment may be spread equally over the following twelve month period. The conversion will be completed in a period as agreed upon.

Public, Private, Street, or Outdoor Lights

Conversion of lights will be made as requested by the Customer and as agreed to by the Company, upon payment of the undepreciated value of the existing light and a $50 per light conversion charge or in accordance with Rates LED-1 or LED-2. To determine the undepreciated value, the Company will review the install date of the fixture(s) at the Customer’s location. If the install date is greater than 23 years from the date of conversion, the undepreciated value will be zero. For fixtures that are not fully depreciated at the time of conversion, the Company will use the 2020 install cost adjusted for inflation to develop an approximate historical cost and depreciate the fixtures using straight line depreciation. The Customer will be responsible for the remaining undepreciated value.

Energy Emergency Service

In the event of a generally recognized national and/or regional energy shortage or emergency, annual outdoor lighting may be disconnected upon written request of the Customer. In this event, a monthly charge will be billed at the rate of 80% of the monthly luminaire charges for the duration of time the lighting service is disconnected.

Outdoor Lighting Service Rate LED-1

Availability

Public Lighting

Available for Street or Highways and areas within the public domain for customers designated as governmental entities, inclusive of the state, municipalities, or other public authorities. Installations on limited access highways, tunnels, bridges and the access and egress ramps thereto are subject to the Special Rate Conditions of this tariff.

Private Lighting

Available to private customers for outdoor lighting of areas on private property where necessary fixtures can be supported on existing poles and where such service can be supplied from existing secondary distribution facilities.

In special circumstances outlined in the pole and accessory section below, the Company will install a wooden pole.

Lighting Services

Service under this rate is for full-night service street lighting whereby the luminaire operates for the entire night time period pursuant to the Hours of Operation provision below. In addition, customers may, at their option, take advantage of part-night service in which the luminaire operates for a portion of the night pursuant to the Hours of Operation provision below. Customers may select the part-night service option at the time of lighting installation or at any time during service. Any request to select the part-time night service option must be made in writing.

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge	3.873
Reliability Enhancement/Vegetation Management	0.008
Total Distribution	3.881
Transmission Charge	1.520
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

No further installation or relocation of Incandescent and Mercury Vapor lights will be made after the effective date of this rate.

Pole and Accessory Charge

An additional monthly charge enumerated below will be applied where the Company is requested to furnish a suitable wood pole for the sole purpose of supporting a luminaire. If at a future date the pole is used for any purpose approved by the Company in addition to supporting a street and/or floodlight luminaire, the pole charge will be terminated. This pole may not be more than one (1) span from the existing secondary service located along a roadway or thoroughfare, and must be reachable for mechanized equipment.

Description	**Monthly Price Per Unit**
Overhead Service	
Wood Poles	$9.20
Underground Service – Non-Metallic Standard	
Fiberglass – Direct Embedded	$9.53
Fiberglass with Foundation < 25 ft.	$16.18
Fiberglass with Foundation >= 25 ft.	$27.05
Metal Poles – Direct Embedded	$19.29
Metal Poles with Foundation	$23.26

Other Charges

Pursuant to RSA 9-E:4, the Company provides a part-night service that, when requested by a customer, will require the replacement of the photoelectric control that will allow for the operation of the luminaire for a portion of the night. The Company shall assess the customer a Part Night Charge of $150 for the installation of each photoelectric control that must be replaced in order for part-night service to be operational and for the removal of such photoelectric control upon the customer's request to return to full-night service. For installation or removal of each photoelectric control made during a scheduled maintenance visit or during the installation of a new outdoor lighting service, the Company shall assess the customer a Part Night Charge of $20 for the installation or removal of each such photoelectric control. The Part Night Charge does not include the cost or fees associated with any work-zone protection, traffic control services and/or permits required to perform the customer requested change, all of which shall be the responsibility of the customer.

For Full-Night Schedule and Part-Night Schedule, the monthly distribution charge is based on the monthly cost of the fixture as provided below:

Lamp Nominal Light Output	Nominal Power Rating		Monthly Fixed Luminaire Charge	Average Monthly kWh		Monthly kWh Charges		Total Distribution Charges	
				Full Night Schedule	Part-Night Schedule	Full Night Schedule	Part-Night Schedule	Full Night Schedule	Part-Night Schedule
(Lumens)	Watts	Kelvin	$/month	kWh/ month	kWh/ month	$/ month	$/ month	$/ month	$/ month
LED Roadway/Highway									
4,000	30	4,000	$5.29	10	5	$0.39	$0.19	$5.68	$5.48
6,500	50	4,000	$5.51	16	8	$0.62	$0.31	$6.13	$5.82
16,500	130	4,000	$8.51	43	22	$1.67	$0.83	$10.18	$9.34
21,000	190	4,000	$16.28	62	31	$2.41	$1.20	$18.69	$17.48
LED Underground									
3,000	30	3,000	$12.32	10	5	$0.39	$0.19	$12.71	$12.51
LED Flood:									
10,500	90	4,000	$8.38	30	15	$1.16	$0.58	$9.54	$8.96
16,500	130	4,000	$9.62	43	22	$1.67	$0.83	$11.29	$10.45
LED Caretaker II									
4,000	30	3,000	$4.75	10	5	$0.39	$0.19	$5.14	$4.94

Limitations on Availability

The availability of this rate to any Customer is contingent upon the availability to the Company of personnel and/or other resources necessary to perform the conversion of existing Fixtures.

Special Rate Conditions

Charges for the operation of outdoor lights may be increased if, in the Company's opinion, lights are to be installed in locations or under conditions such that estimated income will be insufficient to justify the estimated cost of construction.

Choice of Color Temperature

Each fixture type offered under this LED-1 tariff, except the Caretaker II and Underground Residential, is offered with a customer choice of correlated color temperature (CCT) of either 3000 Kelvin (K) or 4000 K. The Caretaker II and Underground Residential lights are only available in 3000 K. If the customer does not select a color temperature, fixtures with a CCT of 3000 K will be provided.

Issued: XX XX, 20XX   Issued by: /s/ Susan L. Fleck
Susan L. Fleck
Effective: XX XX, 20XX   Title: President

Billings

Charges per kWh will be based on the monthly kWh per luminaire on page 116. The monthly kWh amount shall be determined by allocating the number of annual operating hours for streetlights among the months. The average monthly kWh for each light will be used to bill for kWh usage. Luminaire Charges and Pole and Accessory Charges will be based on the monthly rates above as measured from the date of the prior bill to the current bill date.

Hours of Operation

Full-Night Service: All streetlights will be operated every night from approximately one half hour after sunset until approximately one half hour before sunrise, a total of approximately 3,938 hours each year or approximately 328 average monthly hours.

Part-Night Service: All streetlights will be operated every night approximately one half hour after sunset then turning off at a the earlier of: a time equal to one-half of the Full-Night Service period, or five and one-half hours later , a total of no greater than 1,969 hours each year or approximately 164 average monthly hours.

Failure of Lights to Burn

Should any light fail to burn for the full period provided above, and failure is due to some cause of condition which might reasonably have been prevented by the Company, a deduction will be made from the luminaire price of such light, upon presentation of a claim from the Customer. The deduction shall be equivalent to such part of the annual price thereof as is equal to the ratio that the time of any outage bears to the annual burning time of such light or lights. The provisions of this paragraph do not apply when failure to burn is due to an act of God, or an act or order of any Public Authority or accidental or malicious breakage, provided, however, the necessary repairs are made with reasonable dispatch upon notification by the Customer.

Excessive Damage

Excessive damage to poles, lamps, fixtures, or conductors due to wanton or malicious acts will be charged to the Customer at the actual cost of labor and material required for repair or replace the unit. “Excessive damage” is defined as that which occurs more than once a year. Notification of excessive damage shall be made to the Customer by the Company prior to billing for repairs.

Energy Emergency Service

In the event of a generally recognized national and/or regional energy shortage or emergency, annual outdoor lighting may be disconnected upon written request of the Customer. In this event, a monthly charge will be billed at the rate of 80% of the monthly luminaire charges for the duration of time the lighting service is disconnected.

Terms of Service

The customer shall receive and pay for outdoor lighting service for an initial term of five years from the date of installation. Unless notice of termination is given, service shall be extended thereafter for terms of one year. Either the customer or the Company may terminate outdoor lighting service by giving the other written notice at least six months before expiration of a term.

Discontinuance of Lights

Upon expiration of the initial five year term, the Customer may discontinue lights by written notice to the Company. Such discontinuance is contingent upon the customer paying the undepreciated value of the light installation plus a removal charge of $50 per light. Removal of such lights will be completed in a reasonable period as agreed upon.

Conversion of Existing Lights to LED

Public Street Lights

Incandescent lights - To any municipality or other governmental agency so requesting, the Company will initiate a conversion schedule for the replacement of incandescent lights with an appropriate LED. The conversion will be completed in a period as agreed upon.

Mercury vapor and high pressure sodium lights - To any municipality or other governmental agency so requesting, the Company will initiate a conversion schedule for the replacement of mercury vapor and high pressure sodium lights with an appropriate LED upon payment of the undepreciated value of the existing light. This payment may be spread equally over the following twelve month period. The conversion will be completed in a period as agreed upon.

Public, Private, Street, or Outdoor Lights

Conversion of lights will be made as requested by the Customer and as agreed to by the Company, upon payment of the undepreciated value of the existing light and a $50 per light conversion charge or in accordance with Rates LED-1 or LED-2. To determine the undepreciated value, the Company will review the install date of the fixture(s) at the Customer's location. If the install date is greater than 23 years from the date of conversion, the undepreciated value will be zero. For fixtures that are not fully depreciated at the time of conversion, the Company will use the 2020 install cost adjusted for inflation to develop an approximate historical cost and depreciate the fixtures using straight line depreciation. The Customer will be responsible for the remaining undepreciated value.

Outdoor Lighting Service Rate LED-2

Availability

This rate is only available to customers that are as governmental entities, inclusive of the state, municipalities, or other public authorities who are converting from high pressure sodium, mercury vapor, or incandescent lighting to Light Emitting Diode ("LED") or that want new LED street light installations and that want to purchase and own the LED fixtures including the option to install advanced controls for alternative lighting schedules. Installations on limited access highways, tunnels, bridges and the access and egress ramps thereto are subject to the Special Rate Conditions of this tariff.

Public Lighting

Available for Street or Highways and areas within the public domain for customers designated as governmental entities, inclusive of the state, municipalities, or other public authorities. Installations on limited access highways, tunnels, bridges and the access and egress ramps thereto are subject to the Special Rate Conditions of this tariff.

Lighting Services

Service under this rate is for full-night, part-night or an alternative schedule with the use of advanced controls. Service under this rate for full-night service street lighting is where the luminaire operates for the entire night time period pursuant to the Hours of Operation provision below. In addition, customers may, at their option, take advantage of part-night service in which the luminaire operates for a portion of the night pursuant to the Hours of Operation provision below. Customers may select the part-night service option at the time of lighting installation or at any time during service. Any request to select the part-time night service option must be made in writing. Service under the alternative schedule with advanced controls is where the luminaire operates for an alternative schedule pursuant to the Use of Advanced Controls provision below.

Conversion

Customers choosing to convert from service under Rate M, LED-1, or requesting new service under Rate LED-2 must:

1. Furnish any fixtures accepted by the Company, and pay either the Company per the Installation provision below or a private line contractor, as described under the "Additional Requirements" section below, for the installation of these fixtures.
2. Contribute to the Company either the cost of removal per the Removal provision below or arrange for the private line contractor installing the new LED fixtures to remove and return to the Company the existing fixtures and be responsible for paying the remaining undepreciated value of any street and area lighting fixtures as of the date that such fixtures are removed and replaced with LED fixtures per the Undepreciated Value provision under Rates M and LED-1; and

3. Provide, at least annually, a street light inventory including location of fixtures by pole number, wattage, Kelvin and lumens of all fixtures; The Customer will hold title to all fixtures.

Mounting Brackets and Line Taps

The Company will maintain ownership and maintenance responsibility for mounting brackets and line taps to the point where the Customer's fixture is attached.

Hours of Operation

Full-night outdoor lighting service on an annual basis totaling approximately 3,938 hours of operation per year or approximately 328 average monthly hours and part-night outdoor lighting service on an annual basis totaling no more than 1,969 hours of operation per year or approximately 164 average monthly hours shall be provided for under this rate. Alternative hours of operation shall also be provided under this rate per the Use of Advanced Controls provision below.

Removal and Installation

A customer may request removal only of their lights by the Company for which the customer will be billed $50 per light to cover labor costs associated with removal. Alternatively, the customer may arrange for the private line contractor installing the new LED fixtures to remove and return to the Company the existing fixtures. Customers will be responsible to pay the remaining undepreciated value of the Company's fixtures to be removed prior to removal. The removal will be completed in a period as agreed upon between the Company and the customer. Under this option, the customer shall pay a private contractor for the installation of the new fixtures per the Additional Requirements below.

A customer may choose to have the Company both remove the old fixtures and install the new fixtures. For this service, the customer will be billed $215 per old light fixture by the Company to remove the old fixture and install the new fixture to cover labor costs associated with removal and installation. Customers will be responsible to pay the remaining undepreciated value of the fixtures to be removed prior to removal and installation. The installation will be completed in a period as agreed upon between the Company and the customer.

Replacement and Maintenance

Any customer requesting replacement or maintenance of a light by the Company will be billed $215 per light to cover labor costs associated with replacement and maintenance. Ongoing maintenance or replacement of fixtures owned by the customer, including photocell or advanced controls, may be performed by the customer through a Company approved contractor as described below under Additional Requirements or by a customer employee that is a licensed electrician.

Additional Requirements

Fixtures must be provided by the Customer for installation on the Company's facilities. Fixtures shall be accepted by the Company in advance of installation and must be compatible with existing line voltage and brackets, and must require no special tools or training to install and maintain. Customers who are replacing existing fixtures with LED fixtures are responsible for the cost of removal and installation. Customers may choose to have this work completed by the Company or may opt to hire and pay a private line contractor to perform the work. Any private contractor shall have all the requisite training, certifications and insurance to safely perform the required installations, and shall be licensed by the State and accepted by the Company. Prior to commencement of work, the municipality must provide written certification of the qualifications to the Company. Contractors shall coordinate the installation work with the Company and submit a work plan subject to approval by the Company, including provisions for either returning removed fixtures to the Company or otherwise disposing of them as approved by the Company. The Customer shall bear all expenses related to the use of such labor, including any expenses arising from damage to the Company's electrical system caused by the contractor's actions.

Monthly Rates:

The energy charges for each luminaire will be determined by multiplying the energy charges per kilowatt-hour by the average monthly kilowatt-hours. The Customer is responsible for providing the list of fixtures and wattages to allow the Company to calculate the kWh to be billed. The kWh will be calculated based on the 2020 Farmer's Almanac hours of daylight.

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge per kWh	3.873
Reliability Enhancement/Vegetation Management	0.008
Total Distribution	3.881
Transmission Charge	1.520
Stranded Cost Charge	(0.072)
Storm Recovery Adjustment Factor	0.000

For the alternative schedule, the monthly kWh shall be determined as set forth under Use of Advanced Controls.

Failure of Lights to Burn

Should any light fail to burn for the full period provided above, a deduction will be made from the calculated monthly kWh of such light, upon presentation of a claim from the Customer. The provisions of this paragraph do not apply when failure to burn is due to an act of God, or an act or order of any Public Authority or accidental or malicious breakage, provided, however, the necessary repairs are made with reasonable dispatch upon notification by the Customer.

Use of Advanced Controls

Where lighting controls that meet the current ANSI C12.20 standard have been installed that allow for variation from the Company's outdoor lighting hours schedule under Full-Night Schedule or Part-Night Schedule, the Customer must provide verification of such installation to the Company and a schedule indicating the expected average operating wattage of lights subject to the Customer's control and operation. Upon installation and at any time thereafter, the Customer must also provide the Company access, either directly or indirectly, to the data from the Customer's control system in order for the Company to verify the measured energy use of the lighting systems and modify the billed usage as appropriate on a prospective basis. The schedule of average operating wattage ratings may be revised once per year at the request of the Customer. However, it is the Customer's responsibility to immediately notify the Company of any planned or unplanned changes to its scheduled usage to allow for billing adjustments as may be needed.

The charge for the monthly kilowatt-hours shall be determined on the basis of the average operating wattage of the light sources resulting from installed control adjustments established at the beginning of the billing period multiplied by the average monthly hours of the outdoor lighting hours schedule. The wattage ratings shall allow for the billing of kilowatt-hours according to the schedule submitted by the Customer to the Company and reflect any adjustments from the lighting control system including, but not limited to, fixture trimming, dimming, brightening, variable dimming, and multiple hourly schedules.

Pole and Accessory Charge

An additional monthly charge enumerated below will be applied where the Company is requested to furnish a suitable wood pole for the sole purpose of supporting a luminaire. If at a future date the pole is used for any purpose approved by the Company in addition to supporting a street and/or floodlight luminaire, the pole charge will be terminated. This pole may not be more than one (1) span from the existing secondary service located along a roadway or thoroughfare, and must be reachable for mechanized equipment.

Description	**Monthly Price Per Unit**
Overhead Service	
Wood Poles	$9.20
Underground Service – Non-Metallic Standard	
Fiberglass – Direct Embedded	$9.53
Fiberglass with Foundation < 25 ft.	$16.18
Fiberglass with Foundation >= 25 ft.	$27.05
Metal Poles – Direct Embedded	$19.29
Metal Poles with Foundation	$23.26

Rate EV Plug In Electric Vehicle

Availability

Retail Delivery Service under this rate is available for uses of a customer taking service under Rate D as a separately metered service. By choosing to participate in this Plug In Electric Vehicle rate, the Customer agrees to pay the following charges for a minimum of two years. The charging station shall be connected by means of an approved circuit to a separate electric vehicle charging meter. The rates for energy (kWh) based charges are seasonal with a winter period from November 1 to April 30 and a summer period from May 1 to October 31.

Character of Service

Service supplied under this rate will be single phase, 60 cycle, alternating current, normally three-wire service at a nominal voltage of 120/240 volts or three-wire 120/208 volts, whichever is available at the location.

Rates per Month

The rate per month will be the sum of the applicable Customer and Energy Charges subject to the adjustments in this tariff:

Rates for Retail Delivery Service Effective May 1, 2020 through October 31, 2020

Customer Charge	$11.35 per month

Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)

Distribution Charge Off Peak	3.482
Distribution Charge Mid Peak	5.124
Distribution Charge Critical Peak	9.285
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge Off Peak	3.490
Total Distribution Charge Mid Peak	5.132
Total Distribution Charge Critical Peak	9.293
Transmission Charge Off Peak	0.115
Transmission Charge Mid Peak	1.670
Transmission Charge Critical Peak	11.010
Energy Service Charge Off Peak	2.445
Energy Service Charge Mid Peak	6.801
Energy Service Charge Critical Peak	12.305
Stranded Cost Adjustment Factor	(0.072)
Storm Recovery Adjustment Factor	0.000

Off peak hours will be from 12AM to 8AM and 8PM to 12AM daily.
Mid peak hours will be from 8AM to 3PM daily Monday through Friday, except holidays.
Mid peak hours will be from 8AM to 8PM Saturday, Sunday and holidays.
Critical peak hours will be from 3PM to 8PM daily Monday through Friday, except holidays.

Rate D-11 Battery Storage Pilot

Availability

Retail Delivery service under this rate is available for domestic purposes in an individual private dwelling to selected customers presently served under Rate D or D-10, by which they have chosen to participate in the Battery Storage Pilot, leasing and utilizing Tesla Powerwall 2 batteries and associated equipment behind their meter. The rates for energy (kWh) based charges are seasonal with a winter period from November 1 to April 30 and a summer period from May 1 to October 31. The availability of this rate will be subject to the Company's ability to obtain the necessary meters and to render such service.

Character of Service

Service supplied under this rate will be single phase, 60 cycle, alternating current, normally three-wire service at a nominal voltage of 120/240 volts or three-wire 120/208 volts, whichever is available at the location.

Pilot Requirements

This program is applicable to customers who agree through a signed contract to lease two (2) Tesla Powerwall 2 batteries and associated Gateway equipment and allow the Company or Tesla to control such equipment during predicted peak events.

Customer Responsibilities

The Customer is required to sign the Customer Agreement prior to installation of the Tesla Powerwall 2 battery equipment. The Customer that participates in the pilot shall pay the monthly rate of $50 for a minimum of ten (10) years, or contribute $4,866 upfront to the cost of the batteries. Customers who have purchased premises with Company-owned Powerwall 2 battery equipment must sign a Customer Agreement to continue participation in the program. In the event the Customer does not want to sign the Customer Agreement after the premises have been purchased, the Customer must allow the Company to remove the batteries at no cost to the Customer or the Company if changes to electrical wiring is required. The Customer is required to own and occupy the premises where the Powerwall 2 battery equipment is installed. Customers shall be required to maintain reliable communications with the Powerwall 2 battery equipment system, including maintaining functional internet connectivity with WiFi capabilities. The Customer is responsible for compliance with all warranty requirements as described in the Customer Agreement. The Company is responsible for all maintenance and warranty issues related to the Tesla Powerwall 2 battery equipment and shall provide the Customer with the warranty requirements In the event that the Customer does not stay current with the monthly payments for the Powerwall 2 battery equipment system, the Company may require return of the equipment with proper notice, and the Customer shall be responsible for the removal fees.

Company Responsibilities

The Company or Tesla shall have the ability to control the Powerwall 2 battery equipment at its sole discretion just prior to and during predicted peak events and to charge the battery for the entire period of installation. The Company will provide installation for the Powerwall 2 battery equipment and bidirectional metering equipment. The Company is responsible for maintenance and warranty issues related to the Company-owned Tesla Powerwall 2 battery equipment and associated facilities and systems.

Control Credits

The Company or Tesla will take control of and dispatch the Powerwall 2 battery equipment during predicted peak events. Customers who lease the Powerwall 2 battery equipment from the Company will be compensated in accordance with the Alternative Net Metering Tariff adopted by the Commission in Order No. 26,029 dated June 23, 2017, as described in Section 51 of this tariff, when the Company dispatches the Powerwall 2 battery equipment for predicted peak events.

Rates per Month

The rate per month will be the sum of the applicable Customer and Energy Charges subject to the adjustments in this tariff:

Rates for Retail Delivery Service Effective May 1, 2020 through October 31, 2020

Customer Charge	$14.74 per month
Energy Charges Per Kilowatt-Hour (cents per kilowatt-hour)	
Distribution Charge Off Peak	3.482
Distribution Charge Mid Peak	5.124
Distribution Charge Critical Peak	9.285
Reliability Enhancement/Vegetation Management	0.008
Total Distribution Charge Off Peak	3.490
Total Distribution Charge Mid Peak	5.132
Total Distribution Charge Critical Peak	9.293
Transmission Charge Off Peak	0.115
Transmission Charge Mid Peak	1.670
Transmission Charge Critical Peak	11.010
Energy Service Charge Off Peak	2.445
Energy Service Charge Mid Peak	6.801
Energy Service Charge Critical Peak	12.305
Stranded Cost Adjustment Factor	(0.072)
Storm Recovery Adjustment Factor	0.000

Off peak hours will be from 12AM to 8AM and 8PM to 12AM daily.

Mid peak hours will be from 8AM to 3PM daily Monday through Friday, except holidays.

Mid peak hours will be from 8AM to 8PM Saturday, Sunday and holidays.

Critical peak hours will be from 3PM to 8PM daily Monday through Friday, except holidays.

NHPUC No. 21 - ELECTRICITY
LIBERTY UTILITIES

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Summary of Rates

RATES EFFECTIVE JULY 1, 2020
FOR USAGE ON AND AFTER JULY 1, 2020

Rate	Blocks	Distribution Charge	REP/ VMP	**Net Distribution Charge**	Transmission Charge	Stranded Cost Charge	Storm Recovery Adjustment Factor	System Benefits Charge	Electricity Consumption Tax	**Total Delivery Service**	Energy Service	**Total Rate**
D	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	All kWh	$ 0.05480	0.00008	**0.05488**	0.02660	(0.00072)	-	0.00678	-	**0.08754**	0.07193	**$ 0.15947**
Off Peak Water Heating Use 16 Hour Control[1]	All kWh	$ 0.04732	0.00008	**0.04740**	0.02660	(0.00072)	-	0.00678	-	**0.08006**	0.07193	**$ 0.15199**
Off Peak Water Heating Use 6 Hour Control[1]	All kWh	$ 0.04819	0.00008	**0.04827**	0.02660	(0.00072)	-	0.00678	-	**0.08093**	0.07193	**$ 0.15286**
Farm[1]	All kWh	$ 0.05173	0.00008	**0.05181**	0.02660	(0.00072)	-	0.00678	-	**0.08447**	0.07193	**$ 0.15640**
D-10	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	On Peak kWh	$ 0.11694	0.00008	**0.11702**	0.02269	(0.00072)	-	0.00678	-	**0.14577**	0.07193	**$ 0.21770**
	Off Peak kWh	$ 0.00159	0.00008	**0.00167**	0.02269	(0.00072)	-	0.00678	-	**0.03042**	0.07193	**$ 0.10235**
G-1	Customer Charge	$ 414.69		**414.69**						**414.69**		**$ 414.69**
	Demand Charge	$ 8.81		**8.81**						**8.81**		**$ 8.81**
	On Peak kWh	$ 0.00564	0.00008	**0.00572**	0.02065	(0.00072)	-	0.00678	-	**0.03243**		
										Effective 2/1/20, usage on or after	0.09749	**$ 0.12992**
										Effective 3/1/20, usage on or after	0.07777	**$ 0.11020**
										Effective 4/1/20, usage on or after	0.06715	**$ 0.09958**
										Effective 5/1/20, usage on or after	0.05868	**$ 0.09111**
										Effective 6/1/20, usage on or after	0.05246	**$ 0.08489**
										Effective 7/1/20, usage on or after	0.05790	**$ 0.09033**
	Off Peak kWh	$ 0.00168	0.00008	**0.00176**	0.02065	(0.00072)	-	0.00678	-	**0.02847**		
										Effective 2/1/20, usage on or after	0.09749	**$ 0.12596**
										Effective 3/1/20, usage on or after	0.07777	**$ 0.10624**
										Effective 4/1/20, usage on or after	0.06715	**$ 0.09562**
										Effective 5/1/20, usage on or after	0.05868	**$ 0.08715**
										Effective 6/1/20, usage on or after	0.05246	**$ 0.08093**
										Effective 7/1/20, usage on or after	0.05790	**$ 0.08637**
G-2	Customer Charge	$ 69.13		**69.13**						**69.13**		**$ 69.13**
	Demand Charge	$ 8.86		**8.86**						**8.86**		**$ 8.86**
	All kWh	$ 0.02240	0.00008	**0.02248**	0.02553	(0.00072)	-	0.00678	-	**0.05407**		
										Effective 2/1/20, usage on or after	0.09749	**$ 0.15156**
										Effective 3/1/20, usage on or after	0.07777	**$ 0.13184**
										Effective 4/1/20, usage on or after	0.06715	**$ 0.12122**
										Effective 5/1/20, usage on or after	0.05868	**$ 0.11275**
										Effective 6/1/20, usage on or after	0.05246	**$ 0.10653**
										Effective 7/1/20, usage on or after	0.05790	**$ 0.11197**
G-3	Customer Charge	$ 15.90		**15.90**						**15.90**		**$ 15.90**
	All kWh	$ 0.05036	0.00008	**0.05044**	0.02550	(0.00072)	-	0.00678	-	**0.08200**	0.07193	**$ 0.15393**
T	Customer Charge	$ 14.74		**14.74**						**14.74**		**$ 14.74**
	All kWh	$ 0.04469	0.00008	**0.04477**	0.02620	(0.00073)	-	0.00678	-	**0.07702**	0.07193	**$ 0.14895**
V	Minimum Charge	$ 15.90		**15.90**						**15.90**		**$ 15.90**
	All kWh	$ 0.05179	0.00008	**0.05187**	0.02501	(0.00072)	-	0.00678	-	**0.08294**	0.07193	**$ 0.15487**

[1] Rate is a subset of Domestic Rate D

Issued by: /s/Susan L. Fleck
Susan L. Fleck
Title: President

Dated: xxx xx, 2020
Effective: July 1, 2020

Authorized by NHPUC Order No. xx,xxx in Docket DE 20-xxx, Dated xxx xx, 2020

RATES EFFECTIVE JULY 1, 2020
FOR USAGE ON AND AFTER JULY 1, 2020

Rate	Blocks	Distribution Charge	REP/ VMP	**Net Distribution Charge**	Transmission Charge	Stranded Cost Charge	Storm Recovery Adjustment Factor	System Benefits Charge	Electricity Consumption Tax	**Total Delivery Service**	Energy Service	**Total Rate**
D-11	Customer Charge	$14.74		**$14.74**								**$14.74**
	Monday through Friday											
	Off Peak	$0.03482	$0.00008	**$0.03490**	$0.00115	($0.00072)	-	$0.00678	-	$0.04211	$0.02445	**$0.06656**
	Mid Peak	$0.05124	$0.00008	**$0.05132**	$0.01670	($0.00072)	-	$0.00678	-	$0.07408	$0.06801	**$0.14209**
	Critical Peak	$0.09285	$0.00008	**$0.09293**	$0.11010	($0.00072)	-	$0.00678	-	$0.20909	$0.12305	**$0.33214**
	Saturday through Sunday and Holidays											
	Off Peak	$0.03482	$0.00008	**$0.03490**	$0.00115	($0.00072)	-	$0.00678	-	$0.04211	$0.02445	**$0.06656**
	Mid Peak	$0.05124	$0.00008	**$0.05132**	$0.01670	($0.00072)	-	$0.00678	-	$0.07408	$0.06801	**$0.14209**
Rate EV	Customer Charge	$11.35		**$11.35**								**$11.35**
	Monday through Friday											
	Off Peak	$0.03482	$0.00008	**$0.03490**	$0.00115	($0.00072)	-	$0.00678	-	$0.04211	$0.02445	**$0.06656**
	Mid Peak	$0.05124	$0.00008	**$0.05132**	$0.01670	($0.00072)	-	$0.00678	-	$0.07408	$0.06801	**$0.14209**
	Critical Peak	$0.09285	$0.00008	**$0.09293**	$0.11010	($0.00072)	-	$0.00678	-	$0.20909	$0.12305	**$0.33214**
	Saturday through Sunday and Holidays											
	Off Peak	$0.03482	$0.00008	**$0.03490**	$0.00115	($0.00072)	-	$0.00678	-	$0.04211	$0.02445	**$0.06656**
	Mid Peak	$0.05124	$0.00008	**$0.05132**	$0.01670	($0.00072)	-	$0.00678	-	$0.07408	$0.06801	**$0.14209**
M	Luminaire Charge											
	HPS 4,000	$8.16		**$8.16**								**$8.16**
	HPS 9,600	$9.42		**$9.42**								**$9.42**
	HPS 27,500	$15.62		**$15.62**								**$15.62**
	HPS 50,000	$19.41		**$19.41**								**$19.41**
	HPS 9,600 (Post Top)	$11.04		**$11.04**								**$11.04**
	HPS 27,500 Flood	$15.78		**$15.78**								**$15.78**
	HPS 50,000 Flood	$21.08		**$21.08**								**$21.08**
	Incandescent 1,000	$10.45		**$10.45**								**$10.45**
	Mercury Vapor 4,000	$7.23		**$7.23**								**$7.23**
	Mercury Vapor 8,000	$8.13		**$8.13**								**$8.13**
	Mercury Vapor 22,000	$14.51		**$14.51**								**$14.51**
	Mercury Vapor 63,000	$24.50		**$24.50**								**$24.50**
	Mercury Vapor 22,000 Flood	$16.60		**$16.60**								**$16.60**
	Mercury Vapor 63,000 Flood	$32.13		**$32.13**								**$32.13**
LED-1	Luminaire Charge											
	30 Watt Pole Top	$5.29		**$5.29**								**$5.29**
	50 Watt Pole Top	$5.51		**$5.51**								**$5.51**
	130 Watt Pole Top	$8.51		**$8.51**								**$8.51**
	190 Watt Pole Top	$16.28		**$16.28**								**$16.28**
	30 Watt URD	$12.32		**$12.32**								**$12.32**
	90 Watt Flood	$8.38		**$8.38**								**$8.38**
	130 Watt Flood	$9.62		**$9.62**								**$9.62**
	30 Watt Caretaker	$4.75		**$4.75**								**$4.75**
Poles	Pole -Wood	$9.20		**$9.20**								**$9.20**
	Fiberglass - Direct Embedded	$9.53		**$9.53**								**$9.53**
	Fiberglass w/Foundation <25 ft	$16.18		**$16.18**								**$16.18**
	Fiberglass w/Foundation >=25 ft	$27.05		**$27.05**								**$27.05**
	Metal Poles - Direct Embedded	$19.29		**$19.29**								**$19.29**
	Metal Poles with Foundation	$23.26		**$23.26**								**$23.26**
M & LED-1	All kWh	$0.03873	$0.00008	**$0.03881**	$0.01520	($0.00072)	$0.00000	$0.00678	$0.00000	**$0.06007**	$0.07193	**$0.13200**
LED-2	All kWh	$0.03873	$0.00008	**$0.03881**	$0.01520	($0.00072)	$0.00000	$0.00678	$0.00000	**$0.06007**	$0.07193	**$0.13200**

Dated: xxx xx, 2020
Effective: July 1, 2020

Issued by: /s/Susan L. Fleck
Susan L. Fleck
Title: President

Authorized by NHPUC Order No. xx,xxx in Docket DE 20-xxx, Dated xxx xx, 2020

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
Lead-Lag Study
Cash Working Capital Requirement

Line	Description	Test Year	Average Daily Amount	Revenue Lag	Expense Lag	Net (Lead)/Lag Days	Working Capital Requirement
1	Labor & Operations and Maintenance Expenses						
2	Labor (Payroll)	$ 12,569,317	$ 34,342.40	58.70	(44.95)	13.75	$ 472,193
3	Non-Labor O&M	16,724,091	45,694.24	58.70	(42.25)	16.45	751,729
4	Total Labor & Non-Labor Expenses	$ 29,293,408	$ 80,037				$ 1,223,922
5	Income Taxes						
6	Federal & State Income Taxes	$ 233,034	$ 636.70	58.70	(36.00)	22.70	14,454
7	Total Federal Income Taxes	$ 233,034	$ 637				$ 14,454
8	Taxes Other Than Income Taxes						
9	Payroll Taxes	$ 594,320	$ 1,623.83	58.70	(19.11)	39.60	64,296
10	Property Taxes	4,849,638	13,250.38	58.70	17.46	76.17	1,009,233
11	Taxes Other Than Income Taxes	$ 5,443,958	$ 14,915				$ 1,073,529
12	Total	$ 34,970,401	$ 95,588			24.20	$ 2,311,905

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
Lead-Lag Study
Revenue Lag

Line	Description	Revenue Lag
1	Service Lag	15.21
2	Billing Lag	2.59
3	Collection Lag	40.90
4	Total Revenue Lag	58.70

FERC Account		Average Service Lives (Years)	Net Salvage Value (%)	Depreciation Rate
303	Intangible Plant/Software (Amort.)			
	3-Year	3	N/A	33.33%
	5-Year	5	N/A	20.00%
	10-Year	10	N/A	10.00%
	Distribution Plant			
361	Structures and Improvements	44	-5.0	2.39%
362	Station Equipment	40	-20.0	3.00%
364	Poles, Towers, and Fixtures	44	-60.0	3.64%
365	Overhead Conductors and Devices	43	-40.0	3.26%
366	Underground Conduit	56	-10.0	1.96%
367	Underground Conductors and Devices	46	-40.0	3.04%
368	Line Transformers	37	-30.0	3.51%
369	Services	45	-75.0	3.89%
370	Meters	22	-10.0	5.00%
371	Installations on Customer Premises	10	0.0	10.00%
373	Street Lighting and Signal Systems	30	-10.0	3.67%
	General Plant			
390	Structures and Improvements	65	-5.0	1.62%
391	Office Furniture and Equipment	25	0.0	4.00%
391.1	Software and Desktop Computer Equipment	5	0.0	20.00%
391.2	Laptop Computer Equipment	5	0.0	20.00%
392	Transportation Equipment	12	10.0	7.50%
393	Stores Equipment	30	0.0	3.33%
394	Tools, Shop, and Garage Equipment	24	0.0	4.17%
395	Laboratory Equipment	33	0.0	3.03%
396	Power Operated Equipment	15	10.0	6.00%
397	Communication Equipment	24	0.0	4.17%
398	Miscellaneous Equipment	10	0.0	10.00%