STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities

Petition for Permanent and Temporary Rates

Order Approving Permanent Rates

O R D E R N O. 26,122

April 27, 2018

APPEARANCES: Michael J. Sheehan, Esq., on behalf of Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities; the Office of the Consumer Advocate by D. Maurice Kreis, Esq., on behalf of residential ratepayers; and Paul B. Dexter, Esq., and Alexander F. Speidel, Esq., on behalf of Commission Staff.

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

With respect to the numerous revenue and expense issues, the Commission grants a permanent rate increase for Liberty Utilities (EnergyNorth Natural Gas) Corp., effective May 1, 2018, of $8,060,117 in distribution rates, with a step increase effective the same date estimated to be $4,729,953, for certain non-revenue-producing investments made during 2017, offset by a $2,394,065 reduction due to tax reform. The Commission also consolidates the Keene Division with Liberty's other operating areas for distribution rate purposes, and all

Liberty customers will pay the same distribution rates. A Liberty residential customer (except those in the company's Keene Division) who uses 760 therms per year, is expected to see a total annual bill increase of approximately $85 (or 7.8 percent) as a result of the rate changes. A Liberty residential customer in Keene who uses 693 therms per year will see a decrease of approximately $73 (or 4.6 percent).

I. PROCEDURAL HISTORY

Liberty Utilities (EnergyNorth Natural Gas) Corp. (Liberty or the Company) currently operates two gas divisions in New Hampshire, its EnergyNorth Division, where it serves over 90,000 customers in southern and central New Hampshire and Berlin, and its Keene Division, where it serves approximately 1,200 propane air customers in the City of Keene. On April 28, 2017, Liberty filed a Petition for Permanent and Temporary Rates. The petition and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted to the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2017/17-048.html.

Liberty's petition requested that the Commission grant: (1) a permanent increase in Liberty's distribution rates effective with service rendered on or after July 1, 2017, designed to yield an increase of $13,749,361 in annual revenues; (2) temporary rates effective with service rendered on or after July 1, 2017, designed to yield an increase of $7,778,497 in annual revenues for its EnergyNorth Division, pending the Commission's final determination on the Company's request for a permanent rate increase; and (3) a step adjustment in rates designed to yield an increase of $6,071,562 in annual revenues (to recover costs associated with approximately $41 million of capital expenditures projected to be made during 2017) to be effective no earlier than January 1, 2018. Liberty proposed that the new permanent rates apply to customers in both its EnergyNorth Division and its Keene Division; that is, the Company sought to consolidate its two divisions for purposes of distribution rates.

Liberty's filing included direct testimony and exhibits in support of the proposed rates, and related supplemental information, including the proposed tariff, in accordance with N.H. Code Admin. Rules Puc 1600. By letter dated April 3, 2017, the Office of Consumer Advocate (OCA) indicated that it would be participating in the proceeding pursuant to RSA 363:28.

In Order No 26,015, dated May 8, 2017, the Commission suspended the effectiveness of the permanent rate pending investigation. In Order No. 26,035, dated June 30, 2017, the Commission authorized a temporary rate increase for customers in the EnergyNorth Division designed to collect $6,750,000 on an annual basis. No temporary rates were requested for the Keene Division. Pursuant to RSA 378:29, the permanent rates authorized in this case will be reconciled back to the effective date of the temporary rates, July 1, 2017.

The Commission held a pre-hearing conference in this matter on May 26, 2017, followed by a technical session. Subsequently, the Staff of the Commission (Staff) and the OCA issued several sets of data requests, which Liberty answered. Liberty, Staff, and the OCA met in technical sessions on August 23, August 24, November 1, and November 2, 2017. On November 30, Staff submitted testimony recommending a rate increase for the EnergyNorth Division of $4.0 million annually, effective May 1, 2018, and a step increase effective that same day of $4.3 million. Staff proposed that no change be made to Keene Division rates at this time. The OCA recommended a rate increase of $9.2 million annually for the EnergyNorth Division. Like Staff, the OCA recommended no change to Keene Division rates at this time. Both Staff and the OCA recommended against the proposed consolidation of Keene into EnergyNorth for purposes of distribution rates, because the consolidation would create a subsidy of the Keene customers by the EnergyNorth customers.

On January 25, 2018, Liberty filed rebuttal testimony wherein it revised its requested revenue deficiency to $14.5 million. On February 27, 2018, Liberty filed a settlement signed by Liberty and the OCA, which if adopted would resolve all issues in this proceeding. The settlement called for a rate increase of $10.3 million effective May 1, 2018, with a step adjustment of $5.0 million effective the same day. The settlement would establish a return on equity of 9.4 percent. It would also consolidate the rates for the EnergyNorth and Keene Divisions and adopt a decoupling mechanism. Staff opposed adoption of the settlement stating that, in its view, the settlement would not result in just and reasonable rates, although Staff supported the settlement return on equity of 9.4 percent and certain other terms as reasonable.

Below, we review the record, including the settlement agreement signed by Liberty and the OCA, and make the findings required to support the rate increases and changes approved in this order. Before doing that, however, we address a request for confidentiality of certain records.

II. STAFF'S MOTION FOR CONFIDENTIAL TREATMENT

Staff filed a motion for confidential treatment of certain information contained in a report from The Liberty Consulting Group (LCG) entitled "Recommendations Verifications of Liberty Utilities." On November 30, 2017, Staff filed the LCG report with two redacted data points, as requested by Liberty, concerning Customer Care Department employee engagement scores. Subsequent to filing the report, Staff noted two additional unredacted scores. Consistent with Liberty's initial position (Data Response Staff 6-38), Staff argued that confidential treatment is required because the data points pertain to "internal personnel practices and otherwise confidential information." RSA 91-A:5, IV. Neither Liberty nor the OCA objected to the motion. At a hearing held on March 6, 2018, the Commission stated that it would treat the information as confidential but, would review the motion in more detail and rule after the hearing.

We first address whether the employee engagement scores should be exempt from public disclosure because such information constitutes confidential personnel data. The New Hampshire Right-to-Know Law provides each citizen with the right to inspect all public records in the Commission's possession. RSA 91-A:4, I. Exceptions include "records pertaining to internal personnel practices." RSA 91-A:5, IV. Both Staff and Liberty stated that the employee engagement scores are a record of internal personnel practices, thus requiring confidential treatment.

The New Hampshire Supreme Court, agreeing with the United States Supreme Court, interpreted "personnel … when used as an adjective, refers to human resources matters." *Clay v. City of Dover*, 169 N.H. 681, 686 (2017) (citations omitted). The data points at issue in this case relate to an employee engagement survey, which gauges Liberty's efforts to bolster employee retention. The Commission finds that these data points pertain to overall employee satisfaction and this falls under the category of human resource matters. Thus, these data points relate to internal personnel practices, and are exempt from the New Hampshire Right-to-Know Law. Accordingly, we hereby grant Staff's Motion. *See Hounsell v. North Conway Water Precinct,* 154 N.H. 1, 3 (2006); *Union Leader v. Fenniman,* 136 N.H. 624, 627 (1993) (customary balancing of interests not required with regard to personnel practices exemption).

III. LIBERTY/OCA SETTLEMENT

The settlement filed by Liberty and the OCA calls for rates (which would be paid by both the EnergyNorth and Keene Division customers) that would increase revenues by $10.3 million annually, with a step adjustment effective May 1, 2018, of $5.0 million. The settlement contains a 9.4 percent return on equity.

The settlement increase of $10.3 million, while not itemized, was intended to resolve all revenue requirement issues raised in the case. By its own terms, the settlement states that it reflects resolution of many such issues, including weighted average cost of capital, capital structure, return on equity, prepayments, materials and supplies, the Concord training center, depreciation and amortization, investments to serve iNATGAS, Keene production costs, and Keene emergency response costs. Other revenue requirement issues that were raised by Staff in this case and that would be resolved by the settlement (although not specifically identified in the settlement) include customer count for purposes of calculating revenues, payroll expense related to vacancies, incentive-based pay and severance pay, and test year consulting services.

The settlement also includes important non-revenue provisions, including consolidation of the rates charged by the Keene Division and the EnergyNorth Division, as well as a decoupling plan under which revenue per customer targets would be established for each rate class. Each month, and again at the end of each year, rates would be adjusted up or down to allow the Company to collect the established revenue per customer targets. The monthly adjustments would account for changes in weather. In months when temperatures were colder than normal, customers would receive a credit on their bill to return the increased revenues that Liberty would have collected due to higher usage during the colder than normal temperatures. During warmer months, customers would pay a charge to make up for the reduced revenues attributable to the warmer temperatures. The annual adjustments would account for changes other than weather, such as decreased revenues due to energy efficiency, increased revenues due to favorable economic conditions, and other changes in revenues. Under the settlement, customer charges for residential customers would be reduced and existing declining rate blocks would be flattened.

IV. COMMISSION ANALYSIS

In this case, the Commission is presented with an unusual situation where it is asked to approve a settlement that is supported by the applicant (Liberty) and the OCA, but not by Staff. Staff's position is that the Commission should reject the settlement because it will not produce just and reasonable rates.

The Commission's process for reviewing a settlement is well established. Under RSA 541-A:31, V(a), informal disposition may be made of any contested case at any time prior to the entry of a final decision or order, by stipulation, agreed settlement, consent order, or default. N.H. Code Admin. Rules Puc 203.20(b) requires the Commission to approve the disposition of a contested case by settlement if it determines that the settlement results are just and reasonable and serve the public interest. In general, the Commission encourages parties to attempt to reach a settlement of issues through negotiation and compromise, as it is an opportunity for creative problem solving, allows the parties to reach a result more in line with their expectations, and is often a more expedient alternative to litigation. *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH,* Order No. 25,202 at 17 (March 10, 2011). Even where all parties join a settlement agreement, however, the Commission cannot approve it without independently determining that the result comports with applicable standards. *Id.* at 18. In this case, where Staff has testified that the settlement will not produce just and reasonable rates, our independent review of the settlement terms is of even greater importance than usual.

We are mindful of Section III of the settlement, which contains typical settlement language that the settlement is expressly conditioned on the Commission's acceptance of all of its terms, without change or condition. The central issue of this case is the rate increase request. As indicated, the latest request, as set out in Liberty's rebuttal testimony, is for a rate increase of $14.5 million (and a request for approval to consolidate EnergyNorth and Keene Division rates). Staff's updated recommended revenue increase (applicable only to the EnergyNorth Division) was $5.7 million. Exh. 53 at 6. The settlement revenue requirement increase is $10.3 million. Exh. 29 at 3.

Given the wide divergence of these amounts, the Commission undertook a review of the various issues raised in the case concerning the appropriate revenue requirement in order to test the just and reasonableness of the settlement rate increase of $10.3 million. That review is detailed in the pages that follow. It concludes that a reasonable revenue requirement deficiency for Liberty in this case is $8,060,117 on a consolidated basis (*i.e.*, applicable to EnergyNorth and Keene customers under consolidated rates). Because that amount is significantly different from the settlement revenue deficiency, we conclude the best course of action is to reject the settlement in its entirety and instead order a rate increase of $8,060,117 based on our resolution of the underlying issues. In addition, we address the various other issues raised in this case that do not directly affect revenue deficiency, such as rate design and decoupling.

In the following sections, unless otherwise noted, Liberty's positions are taken from a combination of its original filing, and when appropriate, its rebuttal testimony and exhibits. The OCA's positions are taken from its original filing. For many of the issues discussed below, the settlement did not specifically address the issue. Instead, the settlement purported to resolve all issues raised by Staff and the OCA. To the extent the settlement discussed an issue, we describe the settlement position separately.

A. Revenues – Year-End Customer Count vs. Average Customer Count

Liberty. Liberty based its revenue deficiency calculation on test year (2016) revenues with certain adjustments to, among other things, reflect normal weather, annualize for special contract revenues that were not fully reflected in the test year revenues, and reflect a mid-year increase in cast iron and bare steel replacement revenue. Exh. 3 at 47. Liberty did not adjust test year revenues to reflect revenues from customers that were added during the test year.

OCA. The OCA took no position on the revenue adjustments proposed by Liberty.

Staff. Staff accepted the revenue adjustments proposed by Liberty and proposed an additional adjustment designed to reflect increased revenue from customers added during the test year. Staff's adjustment takes year-end customer counts and calculates a revenue adjustment by multiplying the difference in customer bills at year end by average customer usage, by rate class. The adjustment adds $929,551 to test year revenues, and thus reduces Liberty's requested revenue increase by the same amount. Exh. 40. In support of this adjustment, Staff stated that many inputs to a utility's revenue requirement calculation are adjusted for known and measurable changes during and beyond the test year. Rate base is calculated using year-end, plant balances. Many operation and maintenance (O&M) expenses, including payroll, pensions, property taxes, and the PUC assessment are adjusted for post-test year amounts. 3/14/18 AM, Tr. at 34-36. Further, Staff argued, absent this adjustment, the plant used to serve a customer added during the test year would be in rate base at full value, while only a portion of that customer's revenues would be reflected in the revenue deficiency. 3/14/18 AM, Tr. at 31-34.

Ruling. The Commission finds that Staff's revenue adjustment is reasonable. As Staff noted, many aspects of the revenue deficiency calculation in this case have been updated to reflect known and measurable changes during and beyond the test year. Staff's adjustment better matches plant investments with the revenues realized from those investments and therefore produces a more accurate picture of Liberty's revenues in the period when rates will be in effect.

B. <u>O&M Expenses, Payroll – Vacancies</u>

Liberty. Liberty's revenue requirement calculation included payroll costs for a full complement of employees as of December 31, 2017, one full year after the test year. Exh. 3 at 14-15 and 48. The payroll amount was estimated when Liberty filed its case in May 2017, and the amount was updated in Staff Tech 1-1, filed November 21, 2017. Exh. 17 at 83. Liberty stated that it needs a full complement of employees to perform its necessary tasks. To the extent that a position was vacant during the test year, the tasks of that position were done by temporary employees and/or permanent employees working overtime.

OCA. The OCA took no position on the revenue adjustments related to vacancies proposed by Liberty.

Staff. Staff proposed a reduction in payroll expenses to reflect the equivalent of 3.5 vacancies of a workforce of over 300, which is the average of two historical data points for vacancies: three at January 1, 2016 (the start of the test year), and four as of November 1, 2017, just before Staff's testimony was filed. *Id.* at 21. Staff's position is that vacancies recur and should be reflected in a ratemaking payroll amount that is based on budgeted figures. Further, Staff notes that to the extent the duties of vacated positions were performed by temporary workers, the costs associated with those workers would have been reflected in test year O&M expenses, as outside services. Finally, according to Staff, absent the adjustment, Liberty's proposed payroll expense would be 5.3 percent above test year levels, which is almost twice the average of actual annual payroll increases of 2.7 percent over the past three years. *Id.* at 21-22.

Ruling. Liberty's presentation of rate case payroll is difficult to assess. The Commission prefers a more traditional approach where a utility develops a reasonable test year payroll amount and then applies known and measurable percentage payroll increases to that normalized test year amount. We find Staff's proposed adjustment reasonable. Vacancies are a fact of doing business and should be accounted for when calculating a payroll figure for ratemaking purposes that includes a level of employees that is adjusted beyond the test year, as is the case here. A vacancy level of 3.5 out of a total of over 300 positons is about a 1 percent vacancy rate, which we find reasonable, if not unrealistically low. Furthermore, Staff's adjustment is a smaller reduction than would have been warranted under a more traditional approach to calculating a ratemaking payroll amount, and therefore is reasonable for purposes of this case. Exh. 17 at 21-22.

C. O&M Expenses, Payroll - Incentive Based Pay

Liberty. Liberty's rate request included payroll costs associated with its long-term incentive plan. According to Liberty, incentive compensation pay is a common method of compensating employees and is necessary to attract and retain employees. Exh. 23 at 16.

OCA. The OCA took no position on the questions of incentive based compensation.

Staff. Staff recommended that the Commission deny recovery of $52,000 of Liberty's compensation amount because it was tied to incentives designed to benefit shareholders, but not necessarily customers. Exh. 17 at 60. Staff's adjustment represented approximately five percent of Liberty's requested incentive-based compensation. Exh. 3 at 48. In Staff's view, incentives that reward net income or return on investments are focused on benefits to shareholders. *Id.* at

27. Employees seeking to achieve those targets could do so at the expense of customer service; for example, a reduction in vegetation management (for an electric company) would increase earnings, but could result in a degradation of customer service. 3/21/18, Tr. at 120-121. To remove that possible incentive, Staff recommended that compensation resulting from such incentive targets be excluded from the Company's revenue requirement.

Ruling. The Commission appreciates both the Company's position that incentive-based payroll is standard in today's utility industry and may be required to attract and retain quality employees, and Staff's position that payroll tied to earnings could provide incentives that might result in degradation of customer service. There is no solid evidence, however, that either of those hypotheses is actually valid in the case of EnergyNorth. Because the amount of compensation tied to earnings-based incentives is quite small ($52,000 out of a total company payroll expense of $14,518,000 (Exh. 17 at 83)), the Commission finds Staff's adjustment unnecessary. If the percentage of compensation based on net earnings or stock price were higher, we would take a harder look at the amounts to be included.

D. <u>O&M Expenses, Payroll - Severance Pay</u>

Liberty. Liberty's requested revenue requirement in this case included $144,130 of severance pay, of which $78,000 was related to employees who resigned. Exh. 42; Exh. 17 at 65. Liberty stated that all of the resignations were involuntary and may have involved situations in which the employees granted a release from liability. 3/14/18 AM, Tr. at 46-47,67. Liberty argued that such costs should be included in rates for a number of reasons: (a) severance pay is a normal cost of doing business, (b) not allowing recovery of severance pay could result in higher costs because severance pay can be the least expensive means to resolve an employee dispute, and (c) disallowing severance pay would be substituting the Commission's judgment for the

Company's, which would be particularly inappropriate in this instance where the Commission does not know the specific circumstances under which the severance payments were made. Exh. 23 at 20.

OCA. The OCA took no position on the issue of severance pay.

Staff. Staff believes ratepayers should not pay for costs of removing employees. Ratepayers will have already borne the cost of paying all of the Company's employees to perform. If circumstances are such that employees are being "asked" to resign, ratepayers should not bear the costs. Shareholders should carry the costs of bad hiring decisions, and if the least cost means of removing employees is severance pay, then Liberty should take that course to reduce its costs to shareholders. 3/21/18, Tr. at 129-130.

Ruling. The Commission is persuaded by Staff's position that ratepayers should bear the expense of payroll for services provided, but should not bear severance costs related to employees who resign to avoid being fired. Layoffs (where Staff did not recommend disallowance of related severance pay) could involve reductions in work force where the saved payroll expense would find its way into lower rates. Involuntary resignations, on the other hand, may involve subpar performance, and customers should not be required to bear an underperforming employee's payroll and the severance cost incurred to remove that same employee.

E. Expenses - Consulting Services

Liberty. During the test year, Liberty incurred $43,000 in consulting fees to analyze the proposed Northeast Direct Pipeline (NED) project, which was to bring additional gas supplies to Liberty's service area. The NED project was ultimately abandoned by its developer. Liberty's revenue requirement included full recovery of the $43,000 in rates. Liberty opposed any reduction in this amount because, in the Company's view, consulting fees are an ongoing cost of doing business. While this particular project may have been cancelled, other similar consulting arrangements are likely to be needed every year and thus should be reflected in rates. Exh. 23 at 14-15.

OCA. The OCA took no position on Liberty's consultant expenses.

Staff. Staff recommended that the NED consulting costs be amortized over a three-year period, the effect of which would be that only one third of the expense ($14,000) would be reflected in the rates established in this case. Staff's opinion is that consulting expenses are non-recurring and thus amortization of the NED expense is appropriate so that ratepayers do not pay for the full amount each year. Exh. 17 at 20.

Ruling. The Commission finds that modest consulting costs, like those at issue here, are an ongoing part of a regulated utility's business and should not be amortized. Therefore, the full $43,000 may be included in Liberty's revenue requirement. If the consulting costs were much more significant, amortization might be appropriate.

F. Expenses, Depreciation – Average Service Lives

Liberty. Liberty presented a full depreciation study that was prepared and presented by Paul Normand, who performed EnergyNorth's last depreciation study. Mr. Normand recommended that the average service lives (ASL) of many asset groups be changed from the last study. For example, for account 380.00 – Services, which makes up over 30 percent of the Company's total plant, Mr. Normand recommended that the ASL be increased from 40 years to 45 years. Exh. 10 at 447. For Account 367 – Mains (which makes up almost 50 percent of total company plant), Mr. Normand recommended that the ASL remain at 60 years. *Id.* at 445. Mr. Normand based his recommendations on the results of a recognized and commonly used depreciation model when he considered the model results reasonable. When the model results did not produce results that in his opinion were reasonable, he looked for other information on which to base his conclusions. For example, in the case of account 303.03 – Capitalized Software, Mr. Normand stated that the model results were not reasonable. Exh. 69 at 2-4 (labeled p. 25-27 of 36); Tr. 3/26/18 at 149-152. In that instance, Mr. Normand requested specific information from Liberty regarding the ASLs of the Company's various software packages and used those ASLs in his study results. Exh. 10 at 436; 3/26/18, Tr. At 151-155. In general, in situations where the plant had a communication function, such as automated meters, Mr. Normand relied on his professional judgment in arriving at a shorter ASL due to shortened lives of technology. 3/26/18, Tr. at 156-157.

OCA. The OCA took no position on ASLs.

Staff. Staff agreed with many of the changes to ASLs based on the model results. *See*, *e.g.*, Exh. 18 at 31, Account 320.10 – Other Equipment – Production; Exh. 10 at 440 where Liberty proposed to lengthen the existing ASL from 30 years to 35 years and Staff agreed. When Staff deemed Mr. Normand's study results unreliable, Staff recommended that the last authorized ASLs be used. 3/26/18, Tr. at 198-202. *See, e.g.,* Exh. 18 at 31, Account 303.00 – Capitalized Software. In addition, in the case of meters, where the study analyzed this plant category at the sub-account level for the first time, Staff recommended a more gradual approach. Exh. 18 at 5-6. For example, concerning sub-account 381.20 – Meters – ERTS, Liberty recommended changing the existing life from 35 years to 15 years, while Staff proposed 25 years. Exh. 18 at 5-6 and 32; 3/26/18, Tr. at 203.

Ruling. The Commission is persuaded that Mr. Normand has developed appropriate ASLs for Liberty in this matter. We find his use of extra-study data appropriate in the case of capitalized software and preferable to Staff's reliance on Liberty's prior study. Similarly, we agree with Mr. Normand's judgment that a shorter ASL is appropriate for plant items with significant electronic components such as Meters – ERTS. The approved ASLs are set forth on Appendix 6 attached to this order.

G. Expenses, Depreciation - Amortization of Reserve Deficiency

Liberty. Liberty's depreciation study shows a per books reserve for depreciation as of December 31, 2016, equal to $155,247,000. Mr. Normand calculated a theoretical reserve as of that same date of $165,194,000, leaving a variance of $9,947,000. Exh. 10 at 464. Liberty proposed to amortize this variance over three years. Because the per books reserve is lower than the theoretical reserve, the amortization would result in an increase to rates of $3,316,000 per year. Exh. 3 at 52. Mr. Normand initially recommended that the variance be amortized over two depreciation cycles, or 12 years. Exh. 10 at 405. Mr. Mullen testified that Mr. Normand's 12-year recommendation was based on the depreciation study in isolation and that a broader view would point to a shorter amortization period. Specifically, Mr. Mullen stated that the deficiency itself had accumulated in part due to a 13-year amortization period for a reserve excess from a prior rate case. According to Mr. Mullen, extending the amortization another 12 years would cause inter-generation equity issues. Exh. 72. At the hearing, Mr. Normand testified that while the typical approach would be to amortize a reserve variance over two depreciation cycles, this did not account for Liberty's unusually high investments in mains. 3/26/18, Tr. At 183-184. Mr. Mullen and Mr. Normand agreed that if a shorter amortization period were used, the variance should be looked at in the next rate case (in advance of the next full depreciation study). Exh. 72; 3/26/18, Tr. At 184.

OCA. The OCA took no position on the amortization of the reserve balance.

Settlement. The settlement calls for amortization of the reserve deficiency over five years and a re-examination of the reserve imbalance in Liberty's next rate case.

Staff. Staff recommended a 12-year amortization, consistent with the current amortization, which is passing funds back to customers. Staff noted that depreciation deals with long-lived assets (up to 60 years for mains, which is the largest portion of EnergyNorth's plant) and thus reserve imbalances should be amortized over relatively long periods of time. Exh. 18 at 6-7. Staff sees no reason why reserve shortfalls should be recovered from customers four times quicker than excesses are returned to customers (three years versus twelve years). 3/26/18, Tr. At 208-210. Further, the reserve deficiency at hand is about 6 percent of the total theoretical reserve and Mr. Normand stated that it would be reasonable to amortize reserve variances only when they exceed a 5-10 percent range. *Id.* at 207; Exh. 71. Based on that opinion, Staff asserted that if no amortization is one option, then certainly an accelerated amortization (three years) is not warranted.

Ruling. The Commission's primary goal in addressing this issue is to achieve a result whereby the utility customers pay through rates a level of depreciation that fairly reflects the assets on Liberty's books, and that will result in as minimal a reserve variance as possible at the time of the next rate case. While the Commission approved a 12-year amortization period in the settlement in DG 08-009 (EnergyNorth's last rate case in which a depreciation study was done), that amortization appears to have gone on too long. The Company has gone from a significant reserve excess ($12.4 million) to a reserve shortfall almost as large ($9.9 million). Exh.72; Exh.10 at 464. A three-year amortization period and, to a lesser extent, the five-year period provided in the settlement, may be an over-reaction to the long amortization period from

DG 08-009. The Commission supports the idea of re-examining this reserve variance in EnergyNorth's next rate case (and this is based in large part on Mr. Normand's testimony that a reserve variance review would be a significantly less complicated and less costly task than a full depreciation study – 3/26/18, Tr. at 196). Thus, we approve a six-year amortization period of the existing test year-end balance and direct the Company to prepare and present in its next rate case, a review of the reserve imbalance, a thorough explanation of the cause of any imbalance, and a proposal for amortizing that reserve imbalance.

H. Rate Base - Prepayments

Liberty. Liberty's rate case presentation included $2,705,000 of prepayments in rate base. That figure represented an average test year amount of which $2,431,000 was for property taxes and $274,000 was for other prepayments. Exh. 3 at 71. Liberty also included a $2,636,000 working capital component added to rate base. In response to Staff's assertion that the two rate base components (prepayments and working capital) overlap, Liberty maintained that any overlap is not dollar for dollar and that prepayments should be left in rate base while working capital could be reduced to remove the expenses related to prepayments. No specific adjustment was proposed by Liberty, but Mr. Mullen testified that an adjustment or allowance of some sort was reflected in the settlement. 3/6/18 AM, Tr. at 24-27.

OCA. The OCA took no position on the issue of including prepayments in rate base.

Staff. Staff examined Liberty's lead/lag study and found that every property tax invoice Liberty paid was included. As part of that study, the tax period covered by each invoice, and the number of days from that tax period until each invoice was paid, was quantified and reflected. Exh. 9 at 389-390. Staff thus concluded that there was no need to also include prepaid property taxes in rate base because all cost of money or working capital required for property taxes is precisely reflected in Liberty's lead/lag study. Exh. 17 at 13-15. Staff's adjustment removes prepayments from rate base to eliminate a double count of the working capital associated with prepaid property taxes. *Id.* Staff also removed other, non-property tax prepayments from rate base on the same theory; i.e., that those items were covered in the lead/lag study as O&M expense – Non-Labor. Exh. 9 at 378-381; Exh.17 at 13-15.

Ruling. The Commission finds that the detailed lead/lag study captures all the working capital requirements related to property taxes and other prepaid expenses. To also include prepayments in rate base would be allowing for a double recovery of the working capital related to those items. Consequently, prepayments may not be included in rate base.

Rate Base - Training Center

Liberty. Liberty included in rate base a net plant value of $3,456,000 for its training center at 10 Broken Bridge Road in Concord. Exh. 17 at 55. The facility was placed in service and booked to plant in 2015, one year prior to the test year at a full cost of approximately $3.8 million. 3/6/18 AM, Tr. at 79. Liberty's proposed rate base cost of service also reflected the test year level of operation and maintenance associated with the training center, as well as rent received from Liberty's New Hampshire electric utility, Granite State Electric Company, pursuant to a lease agreement. Exh. 3 at 57. The training center is approximately 6,000 square feet in size and includes 3,000 square feet of indoor lab space. It includes two classrooms, an outdoor gas leak field, an outdoor pole line, an indoor manhole, live gas appliances, and live electric transformers, switch gear, and meters. Exh. 13 at 23.

According to Liberty, the facility is used and useful. Liberty's view is that the training center represents the most efficient means for it to perform various training exercises, because the environment is controlled and safe, and Liberty owns the facility so it can schedule the facility's use. Exh. 13 at 24. Liberty stated that it explored the possibility of training at other utilities' facilities, but found that was not an available option. *Id.* at 20-21. Similarly, Liberty considered on-the-job-training but determined it would not provide adequate training. *Id.* In addition to using the facility for training, Liberty has located a backup call center in the building. Exh. 18 at 73.

Concerning the cost of the training center, Liberty relied on an audit performed by the Commission's Audit Division, which reviewed all the training center costs and recommended only minor exclusions of costs (approximately $300,000-$400,000). Liberty agreed to exclude approximately $167,000. 3/6/18 PM, Tr. at 91; Exh. 26A at 137. Liberty also noted that LCG reviewed all the training cost expenditures and did not recommend any rate base exclusions. 3/6/18 PM, Tr. at 91. Concerning increases from the original cost estimates, Liberty conceded that its initial cost estimates were "outdated and lacking in several ways." Exh. 13 at 18. Liberty maintained that training center costs were controlled and its investment was cost-effective. *Id.* at 16; Exh. 26A at 136. Liberty disputed Staff's position that the Company's training costs have increased significantly since the training center was built. 3/6/18 PM, Tr. at 27-30.

OCA. The OCA's original position was that all costs associated with the training center be removed from rates based on imprudent planning and mismanagement of the project. *See* Exh. 16 at 228-237.

Settlement. The settlement agreement included the costs of the training center in Liberty's rate base and, according to its terms, reflected in the revenue requirement consideration and compromise of the issues raised by Staff and the OCA. Exh. 29 at 6.

Staff. Staff recommended full exclusion of the training center from rate base and exclusion of the revenues and O&M expenses from Liberty's cost of service on the grounds that

Liberty did not perform adequate analysis of the costs and benefits of building the training center. Staff noted that Liberty's decision to build the training center was based on a business case dated January 24, 2014, in which Liberty stated that its cost would be $1,028,100, and the payback would be less than three years due in large part to $400,000 per year in avoided outside training costs. Exh. 18 at 50. Liberty's senior management approved that business case. 3/6/18 AM, Tr. at 81-82. Staff observed that over half of the $400,000 savings were related to trainer costs, which would not be saved if the training center were built, because Liberty would need to hire two full-time trainers. 3/6/18 AM, Tr. at 89-91; Exh.18 at 58.

According to Staff, Liberty did not perform a quantitative assessment of the efficiencies it expected to achieve by building the training center versus performing on-the-job training. Staff also criticized Liberty for never issuing a Request For Proposals for training services. Exh.18 at 21-22. Staff observed that, even when the projected cost of the facility had doubled (to $2.3 million) and that cost increase was brought to senior management for review in an Over Expenditure Spending Request Form, no quantitative assessment of alternatives to completing the training center was performed. Exh. 31 at 5; 3/6/18 PM, Tr. at 14-15.

Staff asserted that the initial estimate of $1,028,100 did not include site work and was prepared without the benefit of a contractor. Exh. 30. Staff also noted that even after a construction contract was later signed with North Branch Construction, there were many additional items that were not included in the estimate, including costs associated with environmental consulting, overheads/burdens, and Allowance For Funds Used During Construction (AFUDC). 3/6/18 AM, Tr. at 112; Exh. 31 at 3.

Staff suggested that a reasonable utility executive should have known about the various construction and training costs that were either not estimated or were underestimated when the project was first reviewed and approved by Liberty's senior management. Staff maintains that, when the significant cost increases were presented to senior management in the Over Expenditure Spending Request Form, Liberty should have re-examined its options for training instead of making unsupported claims that alternatives were "expensive" and "not feasible." Exh. 31 at 4-5; 3/6/18 PM, Tr. at 14-15. Staff believes that if proper analyses were performed then Liberty would have decided against building the training center. Exh. 18 at 19-25. Because such analyses were not performed, Staff maintains that no training center related costs should be charged to customers. Staff also noted that the costs of training have increased significantly since the training center was built. *Id.*

Ruling. Many prior Commission decisions give guidance as to the appropriate standard to apply when evaluating the prudence of a utility's investment. Pursuant to RSA 378:28, the Commission shall not include in permanent rates any return on any plant, equipment, or capital improvement which has not first been found by the Commission to be prudent, used, and useful. *Pittsfield Aqueduct Company, Inc.,* Order No. 25,051 at 13 (December 11, 2009). When reviewing whether a utility has been prudent in its decision making, we "may reject management decisions when inefficiency, improvidence, economic waste, abuse of discretion or action inimical to the public interest are shown." *Public Service Company of New Hampshire,* Order 25,565 at 20 (August 27, 2013) (citing *Appeal of Easton*, 125 N.H. 205, 215 (1984)). "One of the critical prudence considerations when evaluating actions and decisions, is not to apply the perspective of hindsight, but rather to consider the actions in light of the conditions and circumstances as they existed at the time they were taken." *Public Service Company of New Hampshire,* Order No. 24,108 at 26 (December 31, 2002).

The record in this case indicates that Liberty's senior management decided to construct the training center based on the business case dated January 24, 2014, (Exh. 18 at 48-51), which showed its projected cost as $1,028,100 and its projected savings as $400,000, resulting in a three-year payback. Based on those parameters, as Staff noted, the decision to proceed with the project could be found to be prudent. Prior to commencing construction, however, the Commission expects a reasonable utility executive to make certain that projected costs are accurate and reasonable and have been appropriately evaluated.

Concerning projected costs, the record demonstrates that the $1,028,100 was not a reasonable estimate. First, it did not include site work (defined by Liberty as excavation, surveying, and related work – 3/6/18 AM, Tr. at 100), which is essential to any project being built from the ground up, as this project was. Site work proved to be significant in this case, (estimated at $328,000 by North Branch consulting) and there is no explanation as to why this item should have been excluded from the business case analysis. In addition, the business case was prepared without the benefit of a contractor bid, despite the fact that the estimated contractor costs of $439,000 made up over 40 percent of the total projected costs of $1,028,100. A reasonable decision maker would have sought bids for this significant cost element before proceeding. Again, contractor costs proved very significant. A September 2014 contract with North Branch called for over $2 million in costs - nearly five times the amount built into the original estimate. Further, when the contract with North Branch was signed, all parties involved knew that additional costs would be involved. 3/6/18 AM, Tr. at 112. Such costs included basic building components like architectural fees, civil engineering fees, security costs, burdens (overhead), other contractor costs, environmental consulting costs, AFUDC, and others which ultimately totaled over $1.2 million. Exh. 56 at 95-96. A reasonable decision maker, knowing that additional costs were not covered in the contractor bid, would have sought to have those costs estimated and included in the evaluation process.

In August 2014, after construction had begun on the training center, Liberty's senior management was presented with an Over Expenditure Spending Request Form seeking approval of an additional $1.2 million, bringing the projected cost of the center to $2,347,000. Exh. 31 at 4. That Form identified wetlands, soil conditions, and drainage issues as the primary reasons for the additional costs. *Id.* At that time, Liberty was aware of its obligation to rebuild Broken Bridge Road, and to extend the municipal water system to the facility, yet those costs were not mentioned or reflected in the Over Expenditure Spending Request Form. Exh. 33 at 5; 3/14/18 PM, Tr. at 40-41. In fact the municipally-imposed costs were not reflected until June 2015, one year after Liberty knew of those obligations. Exh. 56 at 95. Given this increase in the estimated costs – more than double – a reasonable executive would have performed an extensive, detailed analysis of the costs to complete the project and the cost of any alternatives to completion.

Concerning the projected savings contained in the January 24, 2014, business case, Staff correctly noted that over half of the projected savings were for trainer costs that would not be avoided if training were brought in house because trainers would need to be hired.

While Liberty discussed economic and non-economic reasons for pursuing the training center, and resulting efficiencies, the Company made no attempt to evaluate those factors in a systematic, complete format. Exh. 18 at 56-57, 62, 68 and 72. Such an analysis is fundamental to ensure that a significant investment is prudent. Other than the flawed three-year payback analysis presented with the January 24, 2014, business case, Liberty performed no financial analysis of this project. We believe that Liberty should have performed a robust financial analysis of this project at its outset, and should have examined the project when costs began to increase significantly shortly after its initial estimate.

Liberty appears to rely on the used and useful portion of the prudence standard to support its request for full recovery of the training center investment. Staff advocates for full exclusion of the training center costs from rates, on the basis of imprudence. We reject both Liberty's and Staff's positions because, although arguably imprudent, the center, now constructed and in use, provides value to Liberty and its ratepayers for training and for its use as a back-up call center. These functions support the Company's delivery of safe and adequate service. Therefore, we will allow the inclusion of some of the Company's investment in the training center in its rate base.

We find that Liberty can place in rate base and recover the cost of the training center as presented in the August 2014 Over Expenditure Spending Request Form, or $2,347,000. This figure is close to the North Branch contractor estimate of $2,042,000 which included many essential elements that were overlooked in the original business case estimate of $1,028,100. The amount in the August 2014 Form bears some reasonable relation to what an independent contractor thought the building could be built for, and allows additional funds for contingencies and items that were not covered by the contract. Liberty failed to demonstrate that costs beyond the $2,347,000 were prudently incurred, and we will not permit those costs to be included in rates. We will allow all test year operation and maintenance expenses related to the center, because we recognize that those costs will not diminish based on our rate base exclusion and are needed for successful operation of the facility. We find this result appropriately balances the various aspects of our prudent, used and useful standard. *See Boston Gas Co.*, Mass. Dep't of Telecommunications and Energy, DTE 03-40 (2003) wherein the Department made several rate base exclusions of capital project cost overruns because the decisions to incur the over-expenditures were not supported by record evidence.

I. Rate Base - iNATGAS

Liberty. Liberty's proposed rates reflected full inclusion of the $4,816,000 investment Liberty made to provide service pursuant to a special contract with Innovative Natural Gas (iNATGAS), a seller of bulk compressed natural gas (CNG) for transport and for vehicle refueling located on Broken Bridge Road in Concord. The special contract included lease payments to Liberty for land, minimum (take-or-pay) payments for CNG, and volumetric payments to Liberty for CNG. This special contract was reviewed and approved by the Commission in *Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities,* Order No. 25,694 (July 15, 2014), issued in Docket No. DG 14-091. At that time, Liberty's level of investment in the facility was projected to be $2,245,000. The lease was projected to produce different revenue streams under various possible scenarios. The net present values (NPV) of the revenue streams, analyzed over 15 years, were: $1,767,000 under a minimum take-or-pay revenue scenario; $4,732,000 under a baseline scenario of revenues; and $5,541,000 under an accelerated sales assumption level. Exh. 38 at 2.

The final installed cost of Liberty's investment was $4,816,000. 3/6/18 PM, Tr. at 101. The first vehicle fuel sales were made in early 2017 and the first bulk sale to a tractor-trailer customer took place in December 2017. *Id.* Liberty maintains that this arrangement provides benefits to customers, when analyzed over a 15-year period using current costs, excluding an allowance for funds used during construction (AFUDC), at all three revenue scenarios. Liberty forecasts that the facility has the potential to provide significant additional benefits to customers in the future. Liberty claims that its decision to enter into the project was prudent, the plant is used and useful, and thus the cost of the plant and the resulting revenues should be reflected fully in rates. Exh. 24 at 72. In addition, Liberty states that the arrangement provides benefits to existing firm customers in the form of interstate pipeline capacity credits, based on iNATGAS's peak day load. *Id.* at 71-72. According to Liberty, the costs of the facility were reviewed by the Commission's Audit Division and LCG and neither recommended excluding any portion of the facility from rate base. 3/14/18 PM, Tr. at 86.

OCA. The OCA took no position on the iNATGAS investment.

Settlement. The settlement agreement states that the revenue requirement reflects a compromise of the issues raised by Staff related to iNATGAS.

Staff. Staff recommended that Liberty be allowed to recover the revenue requirement associated with the cost of the facility as presented in DG 14-091 ($2,245,000), and that Liberty be required to bear all costs beyond that level, at least until Liberty's next rate case, at which time the project could be re-evaluated using actual sales numbers and costs. Staff did not request a full denial of cost recovery of Liberty's investment to serve iNATGAS, because the project has the potential to provide net benefits to rate payers, over time, depending on the CNG market. Staff maintained that Liberty knew, or should have known, that its cost estimates were too low and that had more accurate estimates of costs and revenues been presented in DG 14-091, Staff might not have recommended approval of the special contract. Exh. 56 at 19-25.

Staff asserted that because the Accelerated Sales Assumption Level has the same maximum annual sales volumes as the Baseline Assumption Scenario, even the baseline scenario could not have been met using the investment figures that were presented in DG 14-091. 3/22/18 PM, Tr. at 97-100. Staff also noted that two of the three revenue scenarios presented could not have been achieved with the level of investment reflected in the analysis, and that the one remaining analysis shows a negative NPV over 15 years when AFUDC, a real cost of the project, is included in the analysis. Exh. 46 at 2.

Staff questioned Liberty's assertion that the arrangement provides benefits to existing firm customers in the form of interstate pipeline capacity credits, based on iNATGAS's peak day load. Staff noted that if additional capacity has to be acquired to serve iNATGAS, the cost of that capacity could exceed iNATGAS capacity credits. Staff did not request a full denial of cost recovery of Liberty's investment to serve iNATGAS, because the project has the potential to provide net benefits to rate payers, over time, depending on the CNG market.

Ruling. The record demonstrates that Liberty's initial analysis of its investment of $2,245,000 was incomplete. That analysis formed the basis of senior management's approval of the project. Exh. 43 at 2-5. First, the initial cost estimate of $2,245,000 did not include AFUDC, although Liberty agreed that AFUDC would be incurred if the project were completed, 3/6/18 PM, Tr. at 108, and it is indisputable that AFUDC could be substantial if the project timeline were extended. Ultimately, AFUDC on this project totaled $436,000.

Second, Liberty's cost estimate included only $865,000 for "piping, meter set, survey, etc." Because the only other costs estimated were $1,000,000 for compressors, $200,000 for land, and $180,000 for contingencies, it is reasonable to conclude that the "piping, meter set, survey, etc." category was intended to cover all other costs of the project (except AFUDC). Liberty was not able to break down the $865,000 among piping, meter set, and other items, beyond noting that the figure would have included surveying, tree removal, more than half of the asphalt and concrete ultimately installed, pump canopies, the connection of the compressors, and perhaps additional items. 3/14/18 PM, Tr. at 30-33. Liberty stated that 4 or 6 inch steel piping was installed with a maximum allowable operating pressure of 750 pounds per square inch. *Id.*

at 34. Liberty also stated that the labor involved in installing the compressors was not included in the compressor figure of $1,000,000. *Id.* at 29. When the actual figures were reviewed, the items that were projected at $865,000 actually cost $3,080,000, an almost fourfold increase. *Id.* at 32.

The first major driver of the increase was the decision to construct a full capacity facility instead of a phased facility, as had been planned and presented to the Commission for review in DG 14-091. Liberty, at a cost of $600,000 to $700,000, accelerated the buildout due to anticipated increased demand, high spot market natural gas prices, and high oil and propane prices following the very cold winter of 2014/2015. Exh. 24 at 68-71. Liberty stated that the additional investments were needed to build the facility necessary to reach the Accelerated Sales Assumption Level presented to the Commission in DG 14-091. *Id.* Exh. 38 at 2. Liberty agreed that the cost of the full buildout should have been included in the 2014 NPV analysis, in order for the accelerated sales scenario to be accurate. 3/14/18 PM, Tr. at 13. Second, Liberty attributed $600,000 of the cost increases to requirements placed by the City to repave Broken Bridge Road and to install a new water main for 2,500 feet. Liberty knew of the City's requirements in mid-June 2014, well before the Commission order approving the special contract was issued on July 15, 2014, yet no update of the DCF analysis was provided to the Commission to reflect this $600,000 cost increase. 3/14/18 PM, Tr. at 41. Third, Liberty attributed $835,000 of the cost increase to design changes involving additional canopies and buildings to protect the various pieces of equipment from weather, and moving the meter closer to the interstate pipeline and further from the CNG facility. Liberty did not explain why those design changes were made after the Commission reviewed the special contract, rather than before. 3/14/18 PM, Tr. at 76-77.

We find it troubling that the analysis Liberty presented to us in 2014, under a request for fast track review of the proposed special contract (3/22/18 AM, Tr. at 27-28) omitted so much material cost information. The fact that this same analysis was also presented to senior management for review and approval of the project brings into question the prudence of Liberty's decision to proceed with the project. Again, prudence is judged on what a reasonable utility executive knew or reasonably should have known when making a decision.

The record demonstrates that the 2014 DCF analysis was flawed and that many costs were missed or underestimated. Including revenues from sales scenarios, while omitting the investment needed to realize those revenues, is a serious mistake. Liberty's inability to breakdown its estimate of "piping, meter set, survey, etc." into its component parts is not acceptable. The notion that the "etc." in this lump sum figure was sufficient to cover tree removal, asphalt, concrete, canopies, and the labor needed to connect the compressors is not credible. A reasonable utility executive being asked to sign off on the $2 million-plus venture would have, or should have, required more detail.

Further, it appears that follow-up review of this project was minimal and was not performed early enough to be of any use. The record contains an Over Expenditure Application dated March 2016 that shows updated costs and updated payback and internal rate of return analyses. That application states that Liberty had already spent 70 percent of required project costs when the report was provided to management. Liberty knew about the municipal requirement for street work and water main extensions totaling $600,000 (25 percent of the total projected cost) in June 2014, almost two years earlier. Liberty should have re-examined the project in 2014.

Liberty was on notice in DG 14-091 that its investments in the project would be subject to prudence review in a future rate case. Exh. 56 at 19. This case, however, was filed with little detail about the iNATGAS investment.

Full exclusion of the cost of the facility would be justified under a strict prudence examination, which focuses on the facts that were known or should have been known at the time of the decision to undertake the project. That said, we are mindful that the iNATGAS facility, like the training center, is in service and appears to be used and useful. In addition, the iNATGAS facility has the potential to provide net benefits to customers in the future, and therefore a complete exclusion of recovery may not be the best overall remedy.

Liberty testified that the winter 2017/2018 revenues were approaching the baseline scenario. 3/14/18 PM, Tr. at 60. Under the baseline scenario, using $4.8 million, the actual costs of the facility, including AFUDC, a NPV of $2.9 million is projected to be returned to customers through base rates over the 15-year study period. Exh. 46 at 2; 3/14/18 PM, Tr. at 4-5. Liberty testified that those projections would be higher if the scenario were re-calculated using updated tax rates and return on equity percentages. 3/14/18 PM, Tr. at 7-8. Liberty also stated that pipeline capacity cost savings will accrue from the project and those savings were not included in the NPV analyses. Exh. 24 at 71-72. The Commission approved the special contract when it was presented as a $2,245,000 investment with $4,732,000 projected to be returned to firm customers through base rates, under a baseline revenue scenario. Exh. 38 at 2. It is doubtful that we would have approved a $4.8 million investment to return $2.9 million to firm customers over 15 years, if we had been presented with such a scenario.

Nevertheless, the plant has been built and, for purposes of the base rates set in this case, we will allow recovery of the plant up to the level of costs presented in DG 14-091 ($2,245,000) plus related O&M expense. We will re-evaluate this investment in Liberty's next rate case and may consider putting more of the investment in rate base at that time. The remedy fashioned here will put ratepayers in the position they were in when this project was approved. Accordingly, we adopt Staff's proposed adjustment.

K. Keene Division Matters

Liberty. In its initial rate case filing, Liberty, proposed that the Keene Division distribution rates be consolidated into the general EnergyNorth distribution rates applicable throughout the sState, pointing out there is no material difference between distribution service to its customers in Keene and elsewhere. Exh. 3 at 22-23. Liberty calculated the revenue deficiency for the Keene Division during the test year to be $712,403. In support of its request, Liberty said consolidation would limit rate case expenses and administrative costs for the Keene Division's small customer base of approximately 1,200 customers. Exh. 3 at 22-23.

The revenue deficiency included a three-year amortization of $201,000 of emergency response costs related to a December 2015 incident at the propane-air plant[1] and $148,410 of production costs that were formally recognized in the Cost of Gas. Exh. 3 at 26 and 63. Liberty proposed maintaining a separate Keene Division Cost of Gas (COG) ratemaking structure, even with the planned conversion to a Compressed Natural Gas/Liquefied Natural Gas (CNG/LNG) fuel structure for the Division. *Id.* at 23-24.

In its rebuttal testimony, Exh. 24, the Company provided additional arguments in support of its concept of rate consolidation for the Keene Division. Liberty opposed Staff's contention, discussed below, that significant cost-shifting would result from rate consolidation, with Liberty

[1] The December 2015 Keene incident involved a failure of the blower system at the Keene production plant that caused the release of carbon monoxide and unburned propane, and necessitated shutdown of the Keene system. The emergency response personnel directed by the City of Keene assisted Liberty in visiting each home to check on occupants and re-light appliances. *See* 3/27/18 Tr. at 119-123.

pointing to an expected monthly bill impact on general Liberty residential distribution rate customers of 37 cents assuming a revenue requirement of $14.7 million. Exh. 24A at 49-50. In response to questioning about the settlement agreement, Mr. Hall testified the monthly impact on general Liberty residential customers would be 26 cents based on the agreed revenue requirement of $10.3 million. 3/21/18, Tr. at 197.

Liberty also pointed to what, in its view, were similar instances of Commission approval of inter-divisional rate consolidations. Exh. 24 at 51. Liberty argued that, in all likelihood, failure to consolidate rates would result in a failure to expand its system, due to Liberty and customer uncertainties regarding the likely costs of expanded service. Eventually, the Keene system would have to be abandoned, due to rate shocks related to Keene-specific distribution revenue requirement shortfalls. Liberty stated that current efforts to convert a small portion of the Keene system to CNG were being done for safety and reliability and to avoid the need for 24-hour coverage at the propane-air plant during the winter months, and is not being done for rate consolidation purposes, nor for growth, although the conversion could lead to additional growth. *Id.* at 52-62. Liberty also presented certain data request responses, schematics, and schedules that delineated Liberty's planned multi-phase approach to distribution-system expansion for Keene. *See* Exh. 24, 73-91.

In its closing statement, Liberty argued that response costs for the December 2015 incident were reasonable and required under RSA 154:8-a. Following the 2015 incident, Liberty decided that the risk of an extreme event was still possible, although unlikely, which justified the 24-7 manned coverage during the winter months. *See* 3/27/18 Tr. at 119-123.

Liberty supported the provisions of its settlement agreement with the OCA pertaining to the Keene Division (discussed below). Liberty also expanded on its points in favor of rate consolidation presented in its direct and rebuttal testimony through oral testimony at hearing. *See* 3/27/18 Tr. at 114-123; *see also* 3/21/18 Tr. at 141-207.

OCA. The OCA's original position was that consolidation at this time was not appropriate, and that revenues associated with the Keene Division should be dealt with in a separate docket.

Settlement. Liberty and the OCA agreed in their settlement that the emergency response costs related to the December 2015 incident and the Keene production costs should be recovered through the Keene Division COG rates over five years during the Keene Division COG winter period, and beginning November 1, 2018. Exh. 29 at 7. They also agreed that Keene Division customers would pay the same distribution rates and be served under the same terms and conditions as all other Liberty customers, effective May 1, 2018. *Id.* at 12.

Under the terms of the settlement agreement, Liberty also agreed to a target amount of additional revenue due to growth in excess of the revenue requirement associated with the direct cost of the investment; if the cumulative excess revenue is less than $200,000 annually, Liberty would reduce its revenue requirement in its next rate case by the difference between $200,000 and the excess revenue. "Excess revenue" would be based on actual load added as of the effective date of permanent rates following the end of the next rate case, plus reasonable anticipated revenue based on customer commitments to take service, both pro-formed for one year following the effective date of permanent rates in the next rate case. This provision was conditioned on Liberty's receipt of the Safety Division's authorization to commence construction of Phase 1 no later than May 1, 2018, and on acquiring appropriate authorization to construct a permanent CNG/LNG facility by May 1, 2019. *Id.* at 12-13. The settlement agreement also specified that Keene customers would begin paying the LDAC as of May 1, 2018, and that the

Keene Division would continue having a separate COG, which would include: (1) propane purchases; (2) CNG/LNG purchases; (3) production costs; (4) revenue requirement associated with CNG/LNG facilities; and (5) revenue requirement associated with fuel inventory. *Id.* at 13.

Staff. Staff opposed the consolidation of the Keene Division's distribution rates with those of EnergyNorth. Exh. 56 at 5. Staff argued that "[c]onsolidating rates at this time will result in cost shifting and cause financial harm to [EnergyNorth's] ratepayers through higher rates to subsidize the Keene [Division] operations." *Id.* Staff agreed with Liberty that the Keene Division does not collect enough revenue to cover its costs, but opposed the approach of rate consolidation as the appropriate remedy.

Staff argued that the order approving the acquisition of the Keene Division in Docket No. DG 14-155 established a "no net harm test" that militates against uneconomic cost shifts resulting from rate consolidation. Exh. 56 at 9, 14-15. Staff argued that such harm to EnergyNorth customers would indeed occur if consolidation were to be approved. *Id.* As the appropriate remedy, Staff recommended that Liberty should either file a separate Keene Division rate filing requesting a distribution rate increase for the Division; a rate plan that would lead to consolidated rates based on a comprehensive business plan and financial analysis that demonstrates a quantifiable benefit for all Liberty customers, or at the very least no net harm; or to discontinue service by demonstrating that continued service can only be provided at a loss and that Keene Division customers can be conveniently converted to an alternate fuel source and utility plant safely abandoned. *Id.* at 9-10.

Staff noted in its testimony that Liberty failed to provide a comprehensive business plan for its originally 4-phased planned expansion for the Keene Division system. The Discounted Cash Flow (DCF) analysis provided during discovery by Liberty fell far short, in Staff's view, of a comprehensive business plan, and provided little or no support regarding the cost and revenue projections used in the DCF analysis. *Id.* at 10. In particular, Staff pointed out that the Liberty DCF analysis for Phase 1 of the planned Keene Division expansion did not include the $418,384 cost of land (for the planned CNG/LNG production facility) that is currently classified as "Property Held For Future Use" and is therefore not eligible for rate recovery. According to Staff, the Phase 1 planned expansion makes use of that land. The land would become used and useful when placed into service and should be included as a conversion cost. *Id.* Staff concluded that, for the Keene Division, Liberty planned to undertake a CNG/LNG conversion and expansion intended to increase capacity and lower rates, but Liberty's filing provided no details as to whether, or how, that conversion/expansion effort would impact the cost to serve Keene and if the Keene Division customer base can support that cost. *Id.* at 11.

Staff raised concerns regarding certain categories of costs that Liberty included in its calculation of the Keene Division revenue deficiency for the test year. Specifically, Staff alleged that Liberty included costs that were outside the test year, and may not have been prudently incurred. Staff noted that it filed a memorandum in Docket No. DG 16-812, the Keene Division 2016-2017 Winter COG proceeding, recommending that certain Keene propane-air gas production costs not be recovered through COG rates, because production costs are reflected in Keene Division's delivery rates, and the costs of manning the Keene production plant on a 24-7 basis may have been imprudent, in Staff's view. *Id.* at 11-13; 35-43. Staff also raised concerns about the appropriateness for recovery, through Liberty's calculated Keene Division revenue requirement, of personnel costs arising from the December 2015 incident.

Staff also concurred, to a certain extent, with Liberty's assessment of a potential "death spiral" if the calculated Keene Division revenue deficiency were recovered solely from Keene

Division customers, which would drive an adverse rate impact. As noted, however, Staff did not endorse the approach of rate consolidation as proposed by Liberty to ameliorate this problem. Exh. 56 at

14-15; *See also* 3/22/18 AM, Tr. at 42-59; 3/27/18 Tr. at 71-75

Ruling. Unreasonable cross-subsidization of expansionary business by an existing utility, or of one class or locality of utility customers by the general customer base of a utility, is to be avoided. *See Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 26,109 at 15-22 (March 5, 2018); *In re: Concord Steam Corporation Non-Governmental Customers*, Order No. 26,017 at 11-12 (May 11, 2017); *see also C. Julian Tuthill El Al. v. Plaistow Electric Light & Power Company*, 8 N.H.P.S.C. 509, 510 (1922). This precedent is undergirded by RSA 378:10, "[n]o public utility shall make or give any undue or unreasonable preference or advantage to any person or corporation, or to any locality, or to any particular description of service in any respect whatever or subject any particular person or corporation or locality, or any particular description of service, to any undue or unreasonable prejudice or disadvantage in any respect whatever." On the other hand, under RSA 378:11, "The provisions of RSA 378:10 shall not require absolute uniformity in the charges made and demanded by public utilities when the circumstances render any lack of uniformity reasonable." The Commission has discretion in balancing the need for fairness in avoiding cross-subsidization with ensuring the overall public interest.

In this instance, evidence has been presented that, barring consolidation of the Keene Division's distribution rates with those of EnergyNorth, the Keene Division's rates will begin to escalate and make service in the City of Keene increasingly uneconomic. Furthermore, Liberty made an argument that any expansion of gas service in the City of Keene, utilizing new

CNG/LNG installations and associated distribution lines, will not be feasible if consolidation of distribution rates is not allowed. Further, there is evidence that consolidation will reduce administrative costs and provide an opportunity for revenue growth in Keene that, if successful, will benefit all Liberty customers. We are persuaded that there will not be an unreasonable cost-shifting by consolidating Keene with EnergyNorth's distribution customers. Such consolidation is consistent with precedent where other smaller utilities acquired by larger utilities are consolidated. *See, e.g., Pennichuck Waterworks Inc.*, Order No. 22,883 (March 25, 1998) (Commission determined an increase of $1.00 a month to Pennichuck's Nashua customers was not unreasonable as part of rate consolidation with smaller companies).

Moreover, we see little difference between consolidating the Keene Division and adding a new franchise territory like Hanover and Lebanon which we have authorized to be included in Liberty's general distribution rates under certain conditions. *See Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities*, Order No. 26,109 (March 5, 2018). We note Liberty's testimony that "prior to completing the business plan, [Liberty] will need to perform a detailed engineering design for the distribution system and supply facility that will be used to plan the construction and expansion of the system." Exh. 24 at 59. Given the unknowns regarding the economic viability and cost structure of Liberty's Keene Division expansion plans, we will apply the risk-sharing provisions imposed on Liberty within the context of its Hanover and Lebanon CNG/LNG expansion effort outlined in Order No. 26,109. We apply those more robust provisions, with some modification, in preference to the settlement agreement's provisions.

Therefore, we will permit the consolidation of Keene Division distribution rates with those of EnergyNorth, subject to the following conditions designed to protect EnergyNorth's distribution customers from potential over- capitalization that could lead to cross subsidization (Keene Division COG rates will remain a separate ratemaking structure):

1. For any of the expansionary Phases planned by Liberty within the City of Keene, prior to beginning construction of any Phase, Liberty must secure a customer commitment level that will produce at least 50 percent of the revenue requirement associated with the new facilities from those customers in 10 years, as calculated in present value terms;

2. Liberty must reduce its revenue requirement by 50 percent of any revenue shortfall in the first distribution rate case filed within five years following construction of each Phase and by 100 percent of any revenue shortfall in the second distribution rate case filed within the five years following the construction of each Phase;

3. In the case of Keene, the revenue requirement to be considered in this analysis would include both production costs and distribution costs, with production costs recovered in the separate Keene COG rate to be applied to Keene customers including the cost of land on which the new Keene CNG/LNG production plant is located, the cost of the current effort to convert a small portion of the system to CNG, the direct costs of the production facilities, propane purchases, CNG/LNG purchases, the revenue requirement associated with CNG/LNG facilities, and the revenue requirement associated with fuel inventory;

4. The direct cost of the Keene distribution system is to be recovered through Liberty distribution rates applicable to all Liberty distribution rate customers;

5. Customer commitment requirements apply to the revenue requirement reflected in both the Keene COG and Liberty distribution rates. Revenue reductions under the risk-sharing conditions set forth in this order will apply to both the Keene COG and Liberty distribution rates based on the Keene investment costs reflected in each;

6. Liberty will file updated DCF analyses at the in-service date of each of the Phases of the Keene expansion project, and annually thereafter, until ordered otherwise. The initial and annual reports will include the following:

i. A comparison of the original and updated DCF analyses;

ii. A comparison of the original annual projected residential and C&I customer conversions and gross profit margins, by fuel type, with the actual annual conversions and gross profit margin; and

iii. A Current Heating Fuel Value table comparing the annual average residential heating rate calculated using the Keene Division bill impact schedule in its COG filing and the cost of alternative fuels in effect at the time as reported by the New Hampshire Office of Strategic Initiatives.

7. Liberty's obligation to meet, pursuant to RSA 374:1, 374:3, and 374:4, the inspectional and operational requirements of the Commission's Safety Division, and to satisfy the Safety Division regarding those requirements, remains in place indefinitely. *See* Order No. 26,065 (October 20, 2017);

8. The risk-sharing condition we impose will terminate following the date on which Keene customers have produced at least 100 percent of the revenue requirement associated with the new facilities for each phase, provided Liberty petitions the Commission to terminate the applicable risk-sharing provision and submits the necessary documentation to demonstrate that the condition for termination has been met.

With respect to the December 2015 incident, we find that the emergency response costs of $201,000 were prudently incurred, and that amortizing recovery of those costs over three years is reasonable.

As for the Keene production costs of $148,410, we find that Liberty failed to justify those costs in this proceeding. Liberty made many significant enhancements to address the risk of a similar event and did not provide evidence that the incremental costs of manning the plant were reasonable or justified. Accordingly, we deny recovery of those costs.

Because we find around-the-clock staffing of the Keene production plant is not just and reasonable, we reject the Company's argument that the current cost of converting a small portion of the Keene system to CNG is necessary for reliability and safety reasons or is economically justified on its own terms. Furthermore, Liberty testified that the conversion could lead to additional growth, and it is therefore appropriate to include the cost of the initial conversion to CNG in the risk sharing mechanism delineated above.

L. <u>Cost of Capital</u>

Liberty. In its initial filing in this matter, Liberty proposed rates based on a weighted average cost of capital (WACC) of 7.36 percent which included a return on equity (ROE) of 10.30 percent and a capital structure consisting of 50 percent common equity and 50 percent long-term debt. Exh. 3 at 69. Liberty did not revise its position in its rebuttal testimony filed in January 2018. Exh. 23 at 26.

OCA. In its initial filing in this case, the OCA recommended a WACC of 6.41 percent, calculated using an ROE of 8.4 percent. Exh. 16 at 238; Exh. 15 at 195.

Settlement. In the settlement, Liberty and the OCA agreed to a WACC of 6.85 percent, an ROE of 9.4 percent, and a capital structure consisting of 49.21 percent common stock, 49.85 percent long-term debt, and 0.95 percent short-term debt. Exh. 29 at 4. The settlement states that this capital structure reflects recently approved long- and short-term debt changes. *Id.* at 3.

Staff. Staff proposed that rates be calculated using a WACC of 6.42 percent, which included an ROE of 8.55 percent and a capital structure consisting of 49.21 percent common equity, 49.85 percent long-term debt, and 0.95 percent short-term debt. Exh. 20 at 77. Staff later agreed that the settlement ROE of 9.4 percent and settlement WACC of 6.85 percent were reasonable for setting rates in this case. 3/6/18 AM, Tr. at 11-12.

Ruling. In light of agreement among Liberty, the OCA, and Staff (parties with strongly different views on many aspects of this rate case), we find the WACC of 6.85 percent and the ROE of 9.4 percent reasonable with one important change. We are approving a decoupling mechanism in this case, which reduces the risk that Liberty will not recover its authorized revenue requirement. In addition, the stabilized cash flow should improve the Company's credit rating and thus its access to lower cost debt.

We reject Liberty's claim that its reduced risk associated with decoupling is already reflected in its recommended ROE (and therefore, presumably, the settlement ROE). Liberty claims that the proxy group of utilities Liberty used to determine its requested ROE already had decoupling. In drawing this conclusion, Liberty does not differentiate between straight fixed-variable rate design, LRAMs, and a weather normalization clause. Instead, Liberty lumps them all under the heading of "decoupling" and states that the proxy group already reflects decoupling. The Commission does not consider rate designs and LRAMs to be comparable to the decoupling provision approved herein in terms of risk of recovery of costs, primarily because the decoupling mechanism we adopt will shield Liberty from swings in weather while rate design changes and LRAMs are unrelated to and unaffected by weather. Most of the companies with decoupling do not include monthly weather normalization.

Accordingly, to account for the decrease in risk Liberty will experience under the approved decoupling mechanism, we will set the ROE in this case at 9.3 percent, resulting in a WACC of 6.8 percent. That ROE is 10 basis points lower than the ROE contained in the settlement.

M. Decoupling

Liberty. Liberty proposed what it termed a full decoupling mechanism, based on revenues per customer. The mechanism was designed to sever the link between Liberty sales and revenues to remove the Company's disincentive to promote energy conservation that is inherent in traditional ratemaking. Liberty's distribution revenue per customer targets would be set based on test year information and then, going forward, rates would be adjusted twice annually (up or down) to allow the Company to collect its target revenue, calculated using actual customer counts. By using a revenue-per-customer mechanism, Liberty has an incentive to add customers and to control costs. The mechanism would shield Liberty from changes in sales due to conservation (both utility sponsored and other) as well as weather swings and economic factors. Exh. 8 at 282-290.

Liberty proposed that the decoupling mechanism be administered to three groups of customers: residential non-heat, residential heat, and all C&I. *Id.* at 320. Liberty also proposed an annual 5 percent cap (based on distribution revenues) on any one adjustment, with provisions for collecting adjustments that went beyond the 5 percent cap. *Id.* at 324. In rebuttal testimony, Liberty proposed administering the mechanism at the rate class level, rather than the three groups identified in its original proposal. Exh. 27 at 178.

OCA. The OCA originally proposed a decoupling mechanism calculated at the total company revenue level (in contrast to Liberty's proposal of a revenue per customer mechanism) that would incorporate weighted historic weather data where more recent years are given more weight. The OCA proposed that decoupling be implemented on what it characterized as a "real-time" basis to improve customer and company cash flows and so that customers see the impact of weather on the bills as it is experienced. The OCA calculated that under its proposed decoupling mechanism, customers would pay significantly less than under the currently approved LRAM, based on recent historical sales (and reflecting recent actual weather). Exh. 14 at 10-22.

Settlement. The settlement decoupling mechanism combined Liberty's revenue per customer target approach with the OCA's monthly weather adjustment. The settlement decoupling mechanism calls for annual adjustments for any additional differences between target and actual revenues per customer (i.e., those not related to weather) calculated for two groups – residential customers and C&I customers. The decoupling mechanism would begin November 1, 2018, at which time Liberty would cease collecting lost revenues attributable to energy efficiency programs, currently collected through a lost revenue adjustment mechanism (LRAM). The settlement also allows Liberty to recover up to $50,000 in costs incurred to upgrade its billing system and related software to implement decoupling. Exh. 29 at 10-12.

Staff. Staff proposed a decoupling mechanism similar to what Liberty initially proposed, but without a weather component. Staff supported adjusting revenues once per year to account for reduced sales from energy efficiency and all other factors, except weather. Staff stated that utilities have always borne the risk and reward for sales deviations due to weather swings and that this risk is unrelated to energy efficiency. Staff proposed that the decoupling adjustment be calculated by rate class. Exh. 18 at 10-14. Staff opposed the settlement decoupling proposal because shielding Liberty from weather impacts was not a stated goal of the Commission's recently adopted Energy Efficiency Resource Standard (EERS) and is unrelated to energy efficiency. Staff believed that the bill credits customers would receive in cold months, when they presumably used more gas, would send anti-conservation price signals. Further, Staff said the administration of the monthly weather adjustment would be complicated and the results would be difficult to audit. 3/26/18 AM, Tr. at 9.

Ruling. All participants in the case propose decoupling mechanisms. Except for the issue of weather, we see little significant difference between the various decoupling mechanisms proposed. Traditionally, gas utility rates are set assuming normal weather and any fluctuations in revenues due to abnormal weather are absorbed by the Company until its next rate case.

The Commission's order in the EERS docket set the stage for utilities to propose decoupling mechanisms to replace the LRAM. The LRAM was intended to be a temporary measure to remove the disincentive for utilities to undertake energy efficiency programs. We applaud Liberty for proposing a decoupling mechanism to replace the LRAM.

We acknowledge the Company's and the OCA's strong support for monthly weather normalization and agree that it would stabilize cash flow for Liberty. We note Staff's point that providing customers a small distribution rate reduction in a month where cold weather causes them to use more gas may send a small counter-intuitive price signal. We are persuaded, however, that the impact will be significantly diminished by the fact that customers' bills in total will be higher during colder months than during warmer months, even with this adjustment, which only affects one portion of the customer's bill.

Accordingly, we approve the settlement decoupling proposal in concept. We also provide the following for clarity and to facilitate implementation. Decoupling may not be used to compensate Liberty for revenue lost due to reduced customer counts. Because decoupling is slated for November 1, Liberty is directed to file within 45 days of this order illustrative tariffs demonstrating the rates, terms, and conditions required to implement decoupling in conformance with existing law. Due to the novelty of the decoupling process in New Hampshire, Liberty must also submit at the same time customer notice and educational materials for review and approval by the Commission.

The settlement would have required Liberty to file its next rate case using an historic test year no later than December 31, 2020, to reset test year revenues in light of the decoupling mechanism. 3/6/18 AM, Tr. at 57. We agree that such a reset is well advised and we adopt such a requirement in this order. Further, to assist the Commission in evaluating Liberty's decoupling, we require the Company to report in its next rate case on the following: (1) the amount of revenue collected or passed back through this mechanism, by year; (2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs; (3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes; (4) an account of efforts taken to educate builders about energy efficiency; (5) a detailed list of meetings with state and local officials and associations to promote energy efficiency; (6) customer feedback resulting from decoupling as implemented through the rate design; and (7) any changes in the Company's credit rating.

The above list is not intended to be exhaustive. In short, we require the Company to demonstrate that decoupling has allowed the Company to "remain an effective champion of energy efficiency" and has unlocked its "ability to enthusiastically support energy efficiency policy goals." Exh. 8 at 282, 286.

N. Rate Design

Liberty. In its original filing, Liberty proposed significant increases to all its customer charges, based on the results of its marginal cost study and bill impact considerations. Under the proposal, a residential non-heating customer (R-1) would see a 40.8 percent customer charge increase ($6.23 per month) as part of a plan to increase customer charges over three rate cases. Residential heating customers (R-3) and residential low income customers (R-4) would see 15.4 percent increases ($3.40 per month). Commercial and Industrial customer charge increases were based on considerations of marginal costs, rate continuity and customer impacts. Proposed C&I increases were: for rate classes G-41 and G-51 (low annual use customers) 15 percent and for rate classes G-42, G-43, G-53 and G-54 (medium and high annual use customers) 10 percent. Exh. 7 at 210-213. Concerning volumetric rates, Liberty proposed to continue its current use of declining block rates for all classes. *Id.* at 213-214.

OCA. The OCA originally proposed reducing customer charges for all classes and flattening, or eliminating, any existing declining rate block structures. Exh. 14 at 106.

Settlement. The rates in the settlement are significantly different than the rates in Liberty's initial proposal. Customer charges for residential non-heating and heating customers would be set at $14.88 per month, which is $2.00 lower than the current R-1 amount and more than $9.00 lower than the current R-3 charge. For R-3 customers, the head and tail block volumetric rates would be set at the same level. R-4 rates would be set at 40 percent of the R-3 rates. All C&I rate components would be increased proportionally. Exh. 29 at 10 and 25. The OCA supported the settlement rate design because it would promote energy efficiency.

Staff. Staff did not recommend changes to Liberty's proposed customer charges. Staff proposed to set the head and tail blocks at the same level and to allocate any decoupling refunds to the head block and any decoupling surcharges to the tail block. Staff proposed this approach for all rate classes to promote energy conservation, because under decoupling, Liberty has an enhanced opportunity to recover its fixed costs. Exh. 18 at 16-18.

Ruling. Given that we approve the settlement decoupling mechanism, it follows that we approve the settlement rate design. We agree with Staff that decoupling greatly increases the Company's ability to recover its fixed costs and therefore, we are comfortable with the significant decreases to the residential customer charges contained in the settlement. Similarly, we support the flat rate block structure for residential customers, which we agree should encourage conservation. Accordingly, we approve the settlement rate design.

O. Tax Act Impacts

During the course of this proceeding, the federal Tax Cuts and Jobs Act of 2017 (2017 Tax Act) was enacted, effective for tax year 2018. The 2017 Tax Act reduced the corporate income tax rate from 35 percent to 21 percent, which reduces a utility's required annual revenues. On January 3, 2018, the Commission opened Docket No. IR 18-001 to investigate how the 2017 Tax Act will affect the expenses of New Hampshire public utilities. *See Investigation to Determine Rate Effects of Federal and State Corporate Tax Reductions,* Order No. 26,096 (January 3, 2018) [2].

The settlement filed in this case calculated the revenue requirement effect of the 2017 Tax Act as $2,394,065, which would have been subtracted from the settlement agreement revenue deficiency of $10.3 million. Exh. 29 at 23. Staff questioned Liberty's methodology and thus, the accuracy of this figure. Recognizing that the Commission would be reviewing the impact of the 2017 Tax Act in a separate investigation, for purposes of this case, Liberty, Staff,

[2] In Order 26,096, the Commission also ordered an investigation of the impacts of the reductions to the New Hampshire Business Enterprise Tax and the Business Profits Tax.

and the OCA agreed that this figure of $2,394,065 should be subtracted from the revenue deficiency ultimately approved in this case. The adjustment may be subject to further adjustment pending the outcome of the separate tax investigation. 3/21/18 PM, Tr. at 45-52.

Ruling. The Commission adopts this approach as reasonable and will use a separate docket to refine the figure of $2,394,065 and make rate adjustments accordingly. In addition, because the final rates will be reconciled back to the effective date of the temporary rates granted in this docket (July 1, 2017), and the difference will be recouped, the recoupment calculation will need to address the difference in the tax rates in 2017 and 2018. Reconciliation of any differences will be addressed in the separate docket established to deal with tax adjustments.

P. <u>Residential Low Income Assistance Program</u>

Liberty. Liberty did not propose a change to the Residential Low Income Assistance Program (RLIAP) in this docket. In response to Staff's proposed change, Liberty stated that any changes to the program should be addressed in a generic docket where the other affected New Hampshire utilities could be involved, so that any changes would be uniform across the utilities.

OCA. The OCA took no position on the RLIAP.

Settlement. The settlement states that the Commission should open a generic docket to address changes to the RLIAP. Exh. 29 at 14.

Staff. Staff recommended that the RLIAP be restructured so that the discount would be calculated on a residential customer's total bill, rather than the base rate portion of the bill as it is currently done. Staff recommended the change so that the discount offered to participants would be closer to the program goals established by the Commission. Staff stated that the change was needed because the base rate portion of a customer's gas bill has increased in recent years while the cost of gas potion has decreased, and thus the total discounts given were trending higher than planned. Exh. 56 at 25-29.

Ruling. We decline to make any changes to the RLIAP in this case and will open a separate docket to consider changes to the RLIAP.

Q. <u>Step Adjustment</u>

Liberty. Liberty proposed one step adjustment effective May 1, 2018, to recover the costs associated with plant investments made during 2017. It sought an increase in base rates of $5,921,000 for the EnergyNorth division, based on $41,438,000 of plant investments, and $151,000 for Keene division investments of $745,000. Exh. 3 at 28-29 and 76-77.

Liberty updated the proposed step adjustment in its rebuttal testimony, where the step increase in rates would recover $5,095,000 on plant investments of $27,465,000, covering both the EnergyNorth and Keene Divisions. Exh. 23 at 39. This figure represents estimated investments for 2017. Liberty proposed to update this figure to reflect actual investments. The amount of $5,095,000 would act as a cap on the proposed step adjustment. The $5,095,000 amount in the rebuttal testimony also reflected an additional $419,600 in O&M expenses related to pension and benefit costs that had previously been capitalized and now needed to be charged to expense due to Financial Accounting Standard (FAS) Update No. 2017-17. Exh. 23 at 22. Liberty stated that it estimated the FAS 2017-17 effect based on 2017 actuarial assumptions and capitalization percentages. *Id.* The figure also included $173,000 in legal fees incurred in 2017 in connection with litigation Liberty undertook in an effort to reduce fees charged by the cities of Concord and Manchester for claimed road degradation, as well as $186,000 in degradation fees incurred during 2017. *Id.* at 39.

OCA. The OCA took no position on the step adjustment.

Settlement. The settlement agreement contained a step adjustment equal to $5,044,835 based on plant investments of $27,955,000 and the same pension/benefit costs, legal fees and degradation fees as the rebuttal testimony. Exh. 29 at 18.

Staff. Staff supported the step adjustment in concept but raised two issues. First, Staff stated that the pension/benefits amount should be updated for 2018 actuarial assumptions when available. 3/6/18 AM, Tr. at 13. Second, Staff disagreed with the inclusion of the full amount of the 2017 legal fees and degradation fees in the step increase and instead recommended that legal fees be amortized over three years, and degradation fees be amortized over 20 years. Exh. 54; 3/21/18 Tr. at 67-76, 137-139.

Ruling. Based on the agreement of the parties, we approve a step increase effective May 1, 2018, estimated at $4,729,953 and limited to $5,044, 835, and reflecting pension and benefit numbers using the latest available actuarial information. Regarding amortization of legal fees and degradation fees, we agree with Staff that to include the full 2017 amount for those items in permanent rates would mean that customers would be paying that full amount each year. We find that a three-year amortization of legal fees and a 20-year amortization of degradation fees is consistent with how Liberty originally proposed to treat those test year costs, is more reflective of what customers would pay in a single year, and is thus more appropriate.

R. <u>Recoupment</u>

The Commission approved a temporary rate increase effective July 1, 2017, in the amount of $6,750,000. The permanent rate increase of $8,060,117 approved in this order is to be effective as of May 1, 2018. Pursuant to RSA 378:29, Liberty may collect an amount equal to what would have been collected if the permanent rate increase had been effect during the temporary rate period. For clarity, the step increase is not reconciled with temporary rates and is effective May 1, 2018.

The settlement includes a recoupment calculation using the settlement revenue deficiency of $10.3 million and provides for collection through the LDAC, with reconciliation. Exh. 29 at 9, 20. We adopt that calculation and recovery method, but modify the amounts for the revenue deficiency approved herein of $8,060,117. *See* Appendix 5 to this Order.

S. Rate Case Expenses

We will provide for the recovery of just and reasonable rate case expenses through the LDAC, using the method outlined in the settlement. Exh. 29 at 9-10. Those costs are currently estimated to be $530,000, subject to review and approval. *Id.* at 22.

V. CONCLUSION

As we observed above, this is an unusual situation. Under New Hampshire law, the rates originally proposed by Liberty were suspended until April 28, 2018, while we investigated the request. Liberty and the OCA reached an agreement that would have resolved all of the issues in the case, but Staff did not join the settlement. Therefore, at the hearing on the merits, Liberty presented neither its full original case, nor its rebuttal position, except as a way to argue for the reasonableness of the settlement. That approach made sense in the context of the hearing, as the settlement did not itemize adjustments to Liberty's original request to arrive at the agreed-upon revenue deficiency. Instead, the "compromise" total revenue figure reflected, in Liberty's view, allowances for the contrary positions taken by the OCA and Staff in their original submissions.

Our choices, therefore, are that we could approve the settlement, accept Liberty's rate request, or set rates based on the record. Given that reality and the way the case was presented, we approached our deliberations using the entire evidentiary record. We went through the areas where Staff identified problems or issues with Liberty's original or rebuttal positions, and resolved those disputes based on governing law, precedent, ratemaking principles, and our collective judgment. The disputes ranged across every aspect of the case. They included revenue and expense issues like the proper time to count customers, payroll, prepayments of obligations like property taxes, and multiple aspects of the depreciation of assets; and they included determinations about the prudence of certain of Liberty's large capital investments, like the construction and use of the Concord training center and the iNATGAS facility. As explained above, the result of all of the decisions we had to make led to a conclusion that we could not approve Liberty's request or the settlement offered by Liberty and the OCA, because neither would have produced just and reasonable rates. Instead, we compiled the effects of the various decisions and calculated a revenue deficiency that will produce rates we find are just and reasonable.

This case also presented significant matters that do not affect the Company's revenue requirement. The two most significant were the proposed consolidation of the rates of the Keene Division with rates charged by the EnergyNorth Division; and the proposed decoupling of rates with monthly weather normalization.

The decision on consolidation presented a number of conflicting objectives, as argued well by the Company and Staff. On balance, we concluded that consolidation is necessary to the continued viability of the Keene Division and is consistent with the approach we approved for the Company's other recent expansions, and determined that the modest shifts of costs to the rest of Liberty's customers are not unreasonable.

Decoupling, as approved in this order, represents a significant change in how Liberty operates. Liberty, the OCA, and Staff all agreed that some measure of decoupling was appropriate for the Company at this time. Decoupling eliminates certain perverse incentives for the Company to encourage usage of gas by its customers, by adjusting rates to ensure a certain level of recovery by Liberty. Including monthly weather normalization, which was championed by the OCA and agreed to by Liberty in its settlement with the OCA, was opposed by Staff. Monthly weather normalization will further reduce risks to Liberty by reducing fluctuations in revenue caused by changes in the weather. If decoupling is implemented successfully, customers should see enhanced opportunities for cost-effective energy efficiency measures to reduce consumption and lower their energy costs.

The decision to authorize decoupling with weather normalization leads to two other decisions. First, it allows the reduction in fixed customer charges, a traditional part of any utility's rate structure. Because decoupling reduces the risk that the utility will not receive its expected revenue, it allows fixed charges to be reduced. It also makes variable charges, based on usage, a larger part of a customer's bill and thus encourages conservation and efficient use. Second, the risk reduction allows for a small reduction in the appropriate return on equity. While the settlement called for that a return on equity of 9.4 percent, a figure Staff agreed would be appropriate, the reduction in risk associated with decoupling leads us to reduce the return on equity to 9.3 percent.

We recognize that this order calls for major changes to the way Liberty interacts with its customers, and we applaud Liberty for bringing forward a number of innovative proposals. As set forth in the body of the order, we will be monitoring the situation in Keene, including the effects of the rate consolidation on the rest of Liberty's customers, and the implementation and effects of decoupling closely in the next few years. In its next rate case, which Liberty must file with a test year no later than 2020, we will require Liberty to demonstrate its efforts to increase energy efficiency in its service territories. We expect Liberty to be in close contact with Staff to ensure smooth transitions and eliminate surprises going forward.

Based upon the foregoing, it is hereby

ORDERED, that Liberty's Petition for Permanent Rates filed on April 28, 2017, is hereby denied; and it is

FURTHER ORDERED, that the Liberty Agreement Regarding Permanent Rates filed by Liberty and the OCA on February 27 and as revised on March 1, 2018, is hereby denied; and it is

FURTHER ORDERED, that Liberty be permitted to increase its base distribution rates effective with service rendered on and after May 1, 2018, by $8,060,117 on an annual basis; and it is

FURTHER ORDERED, that Liberty be permitted to increase base rates for a step adjustment currently estimated to be $4,729,953, said adjustment to be updated for actual figures but such increase to be capped at $5,044,835, effective with service rendered on and after May 1, 2018; and it is

FURTHER ORDERED, that Liberty shall decrease its base rates by an amount equal to $2,394,065 to reflect the impacts of the 2018 Tax Act, said figure to be reviewed and updated in a proceeding established pursuant to DG 18-001 and any adjustment to this number to be made through the LDAC; and it is

FURTHER ORDERED, that effective with service rendered on and after May 1, 2018, customers in Liberty's EnergyNorth and Keene divisions will pay the same distribution rates; and it is

FURTHER ORDERED, that, subject to review, adjustment, and final approval, Liberty is authorized to begin recovery of $530,000 of rate case expenses, through the LDAC effective May 1, 2018, and it is

FURTHER ORDERED, that any adjustments following review and final approval of rate case expenses shall be recovered through the LDAC; and it is

FURTHER ORDERED, that Liberty is authorized to begin recovery of the difference between the authorized annual temporary and permanent rates, through the LDAC effective May 1, 2018; and it is

FURTHER ORDERED, that Liberty shall file its next distribution rate case using a test year ending no later than December 31, 2020, and that rate case shall include a report on the effects of decoupling as detailed above; and it is

FURTHER ORDERED, that Liberty shall file illustrative tariffs and draft customer notices detailing the rates, terms, and conditions associated with decoupling within 45 days from the date of this order; and it is

FURTHER ORDERED, that Staff's Motion for Confidential Treatment filed on January 8, 2018, is hereby granted; and it is

FURTHER ORDERED, that Liberty shall file tariffs conforming with this Order within 15 days of the date of this order, in accordance with N.H. Code Admin. Rules Puc 1603.02(b).

By order of the Public Utilities Commission of New Hampshire this twenty-seventh day of April, 2018.

Martin P. Honigberg Chairman	Kathryn M. Bailey Commissioner	Michael S. Giaimo Commissioner

Attested by:

Debra A. Howland
Executive Director

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Appendices
Docket No. DG 17-048

Liberty Utilities (EnergyNorth and Keene)
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1	15	3.9	Adjustment 9 Remove Keene Production Cost
1	16	3.10	Adjustment 10 Interest Synchronization
2	1		iNATGAS Adjustment
3	1		Impact of Tax Act
4	1		2018 Step Adjustment
5	1		Reconciliation of Permanent and Temporary Rates & Recoupment Amount
6	1		Depreciation Accrual Rates
7	1		Bill Impact - Liberty Residential Heating Customer
7	2		Bill Impact - Keene Residential Heating Customer

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Summary Comparison of Computation of Revenue Requirement and Revenue Deficiency

Line	Description	Company Proposed (A)	Commission Adjustments (B)	Total (C)
1	Rate Base	$ 252,009,027	$ (7,619,599)	$ 244,389,428
2	Rate of Return	7.36%	-0.56%	6.80%
3	Return Requirement	18,547,864	(1,929,383)	16,618,481
4	Adjusted Net Operating Income	9,735,083	1,757,176	11,492,259
5	Deficiency	8,812,781	(3,686,560)	5,126,222
6	Income Tax Effect	5,732,161	(2,397,875)	3,334,286
7	Revenue Deficiency	$ 14,544,943	$ (6,084,435)	$ 8,460,508
8	iNATGAS Adjustment (Appendix 2)		$ (400,391)	$ (400,391)
9	Revenue Deficiency with iNATGAS Adjustment		$ (6,484,826)	$ 8,060,117

Other Base Rate Adjustments Effective May 1, 2018

10	Impact of Tax Act (Appendix 3)	$ (2,394,065)
11	Increase in Annual Revenue	$ 5,666,052
12	2018 Step Adjustment Revenue Requirement (Appendix 4)	$ 4,729,953
13	Increase in Annual Revenue	$ 10,396,005

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Revenue Requirements and Revenue Deficiency

Line	Description	Company Proposed (A)	Adjustments (B)	Total (C)
1	**Rate Base**			
2	Plant in Service	$ 477,955,645	$ (1,327,047)	$ 476,628,598
3	Accumulated Depreciation & Amortization	(156,540,351)	73,137	(156,467,214)
4	Net Plant in Service	$ 321,415,293	$ (1,253,910)	$ 320,161,384
5	Material and Supplies	$ 6,948,817	$ (3,662,176)	$ 3,286,641
6	Prepayments	2,767,078	(2,767,078)	-
7	Cash Working Capital	2,756,124	63,566	2,819,690
8	Accumulated Deferred Income Tax	(80,054,998)	-	(80,054,998)
9	Customer Deposits	(1,823,289)	-	(1,823,289)
10	Total Rate Base	$ 252,009,027	$ (7,619,598)	$ 244,389,428
11	**Rate of Return**	7.36%		6.80%
12	**Return Requirement**	$ 18,547,864	$ (1,929,383)	$ 16,618,481
13	**Revenues**			
14	Operating Revenue	$ 70,845,966	$ 929,551	$ 71,775,517
15	Other Revenues	881,259	-	881,259
16	Total Revenues	$ 71,727,225	$ 929,551	$ 72,656,776
17	**Expenses**	$ (903,867)		
18	O&M-Gas		0	$ (903,867)
19	O&M-Distribution	12,815,613	(46,752)	12,768,861
20	Customer Accounting	6,158,080	-	6,158,080
21	Sales and New Business	163,927	-	163,927
22	Administration & General	12,823,203	(288,014)	12,535,189
23	Depreciation and Amortization	19,270,782	(1,701,987)	17,568,795
24	Taxes other than Income Taxes	11,145,837	(27,545)	11,118,292
25	Income Taxes	1,843,566	1,236,672	3,080,238
26	Ratemaking Adjustment per DG 11-040	(1,325,000)	-	(1,325,000)
27	Total Operating Expenses	$ 61,992,142	$ (827,625)	$ 61,164,516
28	**Net Operating Income**	$ 9,735,083	$ 1,757,176	$ 11,492,259
29	**Income Deficiency**	$ 8,812,781	$ (3,686,560)	$ 5,126,222
30	Revenue Conversion Factor	1.65044		1.65044
31	Revenue Deficiency	$ 14,544,943	$ (6,084,435)	$ 8,460,508
32	iNATGAS Adjustment		$ (400,391)	(400,391)
33	**Revenue Deficiency with iNATGAS Adjustment**		$ (6,484,826)	$ 8,060,117

Notes and Sources
Company Proposed - Exhibit 24A (Simek & Dane Rebuttal Testimony)

Distribution Revenue	$ 71,727,225	$ 72,656,776
Revenue Deficiency	$ 14,544,943	$ 8,060,117
% Increase over Test Year Distribution Revenue	20.3%	11.1%

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Computation of Gross Up for Income Taxes

Line	Description	Company	Adjustment	Adjusted Amount
		(A)	(B)	(C)
1	NH Tax Rate	8.20%		8.20%
2	Federal Statutory Tax rate	34.00%		34.00%
3	Federal Effective Tax rate (1-State rate*Federal rate)	31.21%		31.21%
4	Total Composite Tax rate	39.41%		39.41%
5	Revenue Requirement Gross-Up Factor	60.590%		60.590%
6	Revenue Conversion Factor	1.65044		1.65044

Notes and Sources

Exhibit 53 - Bates page 21 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Rate of Return Calculation - 9.30% ROE

Line	Description	Capital Structure	Cost %	Weighted Cost %
		(A)	(B)	(C)
	Company Proposed Rate of Return			
1	Common Stock	50.00%	10.30%	5.15%
2	Long-Term Debt	50.00%	4.425%	2.21%
3	Total	100.00%		7.36%
	Commission Rate of Return			
4	Common Stock	49.21%	***9.30%***	4.58%
5	Long-Term Debt	49.85%	***4.42%***	2.20%
6	Short-Term Debt	0.95%	2.49%	0.02%
7	Total	100.00%		6.80%

Notes and Sources

Company Proposed: Exhibit 53 - Bates page 23 (Laflamme & Mullinax Supplemental Testimony)
Commission Rate of Return: Exhibit 29 - Bates page 4 (Settlement Agreement)
Commission Rate of Return uses the Settlement Agreement capital structure and cost of debt.

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Impact of Commission **Rate of Return** on Company's Revenue Deficiency

Line	Description	Company Proposed (A)	Adjustment (B)	Commission (C)
1	**Total Rate Base**	$ 252,009,027		$ 252,009,027
2	**Rate of Return**	7.36%	-0.56%	6.80%
3	**Return Requirement**	$ 18,547,864	$ (1,411,251)	$ 17,136,614
4	**Net Operating Income**	$ 9,735,083		$ 9,735,083
5	**Income Deficiency**	$ 8,812,781		$ 7,401,531
6	Revenue Conversion Factor	1.65044		1.65044
7	Revenue Deficiency	$ 14,544,943	$ (2,329,181)	$ 12,215,762

Notes and Sources

Column A: Summary Totals from Schedule 1
Line 2: Schedule 2

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Twelve Months Ending December 31, 2016
Commission Ratemaking Adjustments

Line	Description	Company Proposed (A)	Commission Adjustment 1 (B)	Commission Adjustment 2 (C)	Commission Adjustment 3 (D)	Commission Adjustment 4 (E)	Commission Adjustment 5 (F)	Commission Adjustment 6 (H)	Commission Adjustment 7 (E)	Commission Adjustment 8 (G)	Commission Adjustment 9 (I)	Commission Adjustment 10 (K)	Total Adjustments (J)	Totals (M)
	Reference Schedule		Schedule 3.1	Schedule 3.2	Schedule 3.3	Schedule 3.4	Schedule 3.5	Schedule 3.6	Schedule 3.7	Schedule 3.8	Schedule 3.9	Schedule 3.10		
1	**Rate Base**													
2	Plant in Service	$ 477,955,645				$ (1,327,047)							$ (1,327,047)	$ 476,628,598
3	Accumulated Depreciation & Amortiza	(156,540,351)				73,137							73,137	(156,467,214)
4	Net Plant in Service	321,415,294	-	-	-	(1,253,910)	-	-	-	-	-	-	(1,253,910)	320,161,384
														-
5	Material and Supplies	6,948,817			(3,662,176)								(3,662,176)	3,286,641
6	Prepayments	2,767,078		(2,767,078)									(2,767,078)	-
7	Cash Working Capital	2,756,124	63,566										63,566	2,819,690
8	Accumulated Deferred Income Tax	(80,054,998)											-	(80,054,998)
9	Customer Deposits	(1,823,289)											-	(1,823,289)
10	Total Rate Base	$ 252,009,026	$ 63,566	$ (2,767,078)	$ (3,662,176)	$ (1,253,910)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,619,598)	$ 244,389,428
11	**Rate of Return**	7.36%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
12	**Return Requirement**	$ 18,547,864	$ 4,322	$ (188,161)	$ (249,028)	$ (85,266)	$ -	$ -	$ -	$ -	$ -	$ -	$ (518,133)	$ 16,618,481
13	**Revenues**													
14	Operating Revenue	$ 70,845,966							$ 929,551				$ 929,551	$ 71,775,517
15	Other Revenues	881,259				$ -							-	881,259
16	Total Revenues	$ 71,727,225	$ -	$ -	$ -	$ -	$ -	$ -	$ 929,551	$ -	$ -	$ -	$ 929,551	$ 72,656,776
17	**Operating Expenses**													
18	O&M-Gas	$ (903,867)											$ -	$ (903,867)
19	O&M-Distribution	12,815,613									(46,752)		(46,752)	12,768,861
20	Customer Accounting	6,158,080											-	6,158,080
21	Sales and New Business	163,927											-	163,927
22	Administration & General	12,823,203						(209,833)		(78,181)			(288,014)	12,535,189
23	Depreciation and Amortization	19,270,782				(44,191)	(1,657,796)						(1,701,987)	17,568,795
24	Taxes other than Income Taxes	11,145,837						(18,960)		(8,585)			(27,545)	11,118,292
25	Income Taxes	1,843,566				17,416	653,372	90,172	366,354	34,196	18,426	56,736	1,236,672	3,080,238
26	Ratemaking Adjustment per DG 11-04	(1,325,000)											-	(1,325,000)
27	Total Operating Expenses	$ 61,992,141	$ -	$ -	$ -	$ (26,775)	$ (1,004,424)	$ (138,621)	$ 366,354	$ (52,570)	$ (28,326)	$ 56,736	$ (827,625)	$ 61,164,516
														-
28	**Net Operating Income**	$ 9,735,084	$ -	$ -	$ -	$ 26,775	$ 1,004,424	$ 138,621	$ 563,197	$ 52,570	$ 28,326	$ (56,736)	$ 1,757,176	$ 11,492,260
29	**Income Deficiency**	$ 8,812,780	$ 4,322	$ (188,161)	$ (249,028)	$ (112,041)	$ (1,004,424)	$ (138,621)	$ (563,197)	$ (52,570)	$ (28,326)	$ 56,736	$ (2,275,309)	$ 5,126,221
30	Revenue Conversion Factor	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044	1.65044
31	**Revenue Deficiency**	$ 14,544,943	$ 7,134	$ (310,548)	$ (411,005)	$ (184,916)	$ (1,657,739)	$ (228,785)	$ (929,521)	$ (86,763)	$ (46,750)	$ 93,639	$ (3,755,255)	$ 8,460,506
														$ 8,460,508
32	Percent of Total		0.0%	2.1%	2.8%	1.3%	11.4%	1.6%	6.4%	0.6%	0.3%	-0.6%		

Adjustment 1	Cash Working Capital
Adjustment 2	Remove Prepayments Included in Cash Working Capital
Adjustment 3	Remove Fuel Inventory from Materials & Supplies
Adjustment 4	Training Center at $2,347,000
Adjustment 5	Six Year Recovery Period of Theoretical Reserve Imbalance
Adjustment 6	Modify Payroll, Payroll Taxes, and Benefits for Vacancies
Adjustment 7	Adjust Revenue to Year-End Customer Count
Adjustment 8	Remove Severance Associated with Resignations
Adjustment 9	Remove Keene Production Cost
Adjustment 10	Interest Synchronization

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 1
Cash Working Capital

Line	Description	Company Proposed (A)	Adjustment (B)	Amount (C)
1	**Distribution Expenses**			
2	O&M-Gas	$ (903,867)	$ -	$ (903,867)
3	O&M-Distribution	12,815,613	(46,752)	12,768,861
4	Customer Accounting	6,158,080	-	6,158,080
5	Sales and New Business	163,927	-	163,927
6	Administration & General	12,823,203	(288,014)	12,535,189
7	Total O&M Expense for CWC Calculation	$ 31,056,956	$ (334,766)	$ 30,722,190
8	**Taxes and Interest Expense**			
9	Taxes other than Income Taxes	11,145,837	(27,545)	11,118,292
10	Income Taxes	1,843,566	-	1,843,566
11	Less Deferred Income Taxes	(6,135,425)	-	(6,135,425)
12	Income Taxes (Staff's Adjustments)	-	1,179,936	1,179,936
13	Interest Synchronization	-	56,736	56,736
14	Total Taxes and Interest Expense	$ 6,853,978	$ 1,209,127	$ 8,063,105
15	Total Distribution Expenses Taxes and Interest	$ 37,910,934	$ 874,362	$ 38,785,296
16	Lead/Lag Days Ratio	7.27%		7.27%
17	Total Cash Working Capital	$ 2,756,125	$ 63,566	$ 2,819,691
18	**Impact to Rate Base**	**$ 2,756,125**	**$ 63,566**	**$ 2,819,691**

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 2
Remove Prepayments Included in Cash Working Capital

Line	Description	Company Proposed (A)	Adjustment (B)	Amount (C)
1	EnergyNorth			
2	Prepaid Municipal Property Taxes	$ 2,431,418	$ (2,431,418)	
3	Prepaids	273,561	(273,561)	
4	Keene			
5	Prepaid Municipal Property Taxes	40,229	(40,229)	$ -
6	Prepaids	21,870	(21,870)	-
7	Total Prepayments	$ 2,767,078	$ (2,767,078)	$ -
8	**Impact to Rate Base**	$ 2,767,078	$ (2,767,078)	$ -

Notes and Sources

Proposed EnergyNorth: Exhibit 53 - Bates page 28 (Laflamme & Mullinax Supplemental Testimony)
Column A: Attachment DBS/DSD-2, Schedule RR-EN-5-1 (Revised 11/21/17) and Schedule RR-K

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 3
Remove Fuel Inventory from Materials & Supplies

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Plant Supplies	$ 3,170,967	$ -	$ 3,170,967
2	Gas Stored Underground	2,710,013	(2,710,013)	-
3	Fuel Stock - Propane	884,306	(884,306)	-
4	UG Storage - LNG	67,857	(67,857)	-
6	5-Quarter Average	$ 6,833,143	$ (3,662,176)	$ 3,170,967
7	**Impact to Rate Base**	$ 6,833,143	$ (3,662,176)	$ 3,170,967

Notes and Sources

Exhibit 53 - Bates page 29 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 4
Training Center at $2,347,000
(Management Approved Cost - Exhibit 56, Bates page 93)

Line	Description	Company Proposed (A)	Adjustment (B)	Total (C)
1	**Rate Base**			
2	Concord Training Center	$ 3,674,047	$ (1,327,047)	$ 2,347,000
3	Accumulated Depreciation (See Note)	(218,377)	73,137	(145,240)
4	**Impact to Rate Base**	$ 3,455,670	$ (1,253,910)	$ 2,201,760
5	**Operating Income**			
6	*Revenue*			
7	Granite State Lease Payments Concord Training Center	$ 96,764	$ -	$ 96,764
8	*Expense*			
9	Depreciation Expense	$ 124,757	$ (44,191)	$ 80,566
10	Admin and General			
11	Property and Liability Insurance	350		350
12	Utilities	20,031		20,031
13	All Other Admin and O&M	51,329		51,329
14	Total Admin and General		-	
15	Property Taxes	28,516	-	28,516
16	Total Expenses	224,982	(44,191)	180,792
17	Total Operating Income	$ (128,218)	$ 44,191	$ (84,028)
18	NH Income Tax	8.20%	0.00%	8.20%
19	Effect on NH income tax expense	$ (10,514)	$ 3,624	$ (6,890)
20	Federal Taxable	$ (117,704)		$ (77,138)
21	Federal Income Tax Rate	34%	0.00%	34%
22	Effect on Federal income tax expense	$ (40,019)	$ 13,792	$ (26,227)
23	Total Taxes	$ (50,533)	$ 17,416	$ (33,117)
24	**Impact to Operating Income**	$ (77,685)	$ 26,775	$ (50,911)

Notes and Sources

Exhibit 17 - Bates page 55 (Laflamme & Mullinax Testimony)

	Cost Basis	Depreciation	as % of cost
390 General Structures/Equipment	$ 3,585,294	$ 211,757	5.91%
Other Training Center Plant	88,753	6,619	
Training Center	3,674,047	218,377	
Approved Cost	2,347,000	138,620	(cost * 5.91%)
Other Training Center Plant	88,753	6,619	
Aug '14 Approved Cost	2,435,753	$ 145,240	
SPF Testimoy (BP 93) Aug '14 approved cost	2,347,000		
Actual Cost	3,674,047		
Adjustment - Original less Actual	$ (1,327,047)		

	Plant in Service	Depreciation Rate	Annual Depreciation
390 General Structures/Equipment	$ 3,743,921		
Fast Track Costs Removed in 11/21/17 Update	(158,627)		
Adjusted 390	$ 3,585,294	3.33%	119,390
394 Tools, Shop, Garage Equipment	39,231	5.26%	2,064
397 Communications Equipment	18,313	6.67%	1,221
398 Miscellaneous Equipment	31,209	6.67%	2,082
	$ 3,674,047		$ 124,757
Column A, Lines 10-13: Response to Staff 2-26			
Adjusted 390	2,258,247	3.33%	75,200
394 Tools, Shop, Garage Equipment	39,231	5.26%	2,064
397 Communications Equipment	18,313	6.67%	1,221
398 Miscellaneous Equipment	31,209	6.67%	2,082
	$ 2,347,000		$ 80,566
			$ (44,191)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 5
Six Year Recovery Period of Theoretical Reserve Imbalance

Line	Description	Company Proposed (A)	Adjustment (B)	Amount (C)
1	Depreciation per Books	$ 156,434,621	-	$ 156,434,621
2	Theoretical Reserve with Net Salvage	165,193,965	-	165,193,965
3	Accumulated Reserve on Accounts 392, 396, and 12·	1,187,434	-	1,187,434
4	Depreciation, Theoretical Reserve with Net Salvage	166,381,399		166,381,399
5	Difference	9,946,778		9,946,778
6	Recovery Period	3.00	3.00	6.00
7	Reserve Imbalance Annual Recovery	$ 3,315,593	$ (1,657,796)	$ 1,657,796
18	NH Income Tax	8.20%	0.00%	8.20%
19	Effect on NH income tax expense	$ (271,879)	$ 135,940	$ (135,939)
20	Federal Taxable	$ 3,043,714		$ 1,521,857
21	Federal Income Tax Rate	34%	0.00%	34%
22	Effect on Federal income tax expense	$ (1,034,863)	$ 517,432	$ (517,431)
23	Total Taxes	$ (1,306,742)	$ 653,372	$ (653,370)
24	**Impact to Operating Income**	$ (2,008,851)	$ 1,004,424	$ (1,004,426)

Notes and Sources
Column A: Exhibit 53 - Bates page 32 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 6
Modify Payroll, Payroll Taxes, and Benefits for Vacancies

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	**Payroll**			
2	Proforma Total Salary and Wages	$ 29,788,526		$ 29,788,526
3	Less Salaries for Average Vacancies			
4	Average Vacant Positions during 2017		3.50	
5	Average Salaries and Wages per Position		$ 96,092	
6	Adjusted Total Salaries and Wages	$ 29,788,526	$ (336,322)	$ 29,452,204
7	Allocation factor to EN	71.2%		71.2%
8	Salaries and Wages to EN	$ 21,203,848		$ 20,964,450
9	Allocation factor to EN OpEx	72.1%		72.1%
10	Salaries and Wages to EN OpEx	15,293,697	(172,671)	15,121,026
11	**Payroll Taxes**			
12	Proforma Total Salary and Wages	$ 29,788,526	$ (336,322)	$ 29,452,204
13	Payroll Tax Rate (%)	10.98%		10.98%
14	Adjusted Total Payroll Taxes	3,270,922		3,233,992
15	Allocation factor to EN	71.2%		71.2%
16	Payroll Taxes to EN	$ 2,328,284		$ 2,301,997
17	Allocation factor to EN OpEx	72.1%		72.1%
18	Payroll Taxes to EN OpEx	1,679,321	(18,960)	1,660,361
19	**Employer Benefits**			
20	Proforma Total Salary and Wages	$ 29,788,526	(336,322)	$ 29,452,204
21	Health Care and Other / Proforma Total Salaries and Wages	17.5%		17.5%
22	Health Care and Other	5,203,308	(58,747)	5,144,561
23	Proforma Total Salary and Wages	$ 29,788,526		$ 29,452,204
24	401(k) Matching / Proforma Total Salaries and Wages	4.00%		4.00%
25	401(k) Matching	1,191,541		1,178,088
26	Adjusted Total Health Care and 401(k) Match	$ 6,394,849		$ 6,322,649
27	Allocation factor to EN	71.4%		71.4%
28	Health Care and 401(k) Match to EN	$ 4,563,252		$ 4,511,731
29	Allocation factor to EN OpEx	72.1%		72.1%
30	Health Care and 401(k) Match to EN OpEx	3,291,474	(37,162)	3,254,312
31	Total Payroll, Payroll Taxes, and Benefits	$ 20,264,491	$ (228,793)	$ 20,035,699
32	NH Income Tax	8.20%	0%	8.20%
33	Effect on NH income tax expense	$ (1,661,688)	$ 18,761	$ (1,642,927)
34	Federal Taxable	$ 18,602,803		$ 18,392,772
35	Federal Income Tax Rate	34%	0%	34%
36	Effect on Federal income tax expense	$ (6,324,953)	$ 71,411	$ (6,253,542)
37	Total Income Taxes	$ (7,986,641)	$ 90,172	$ (7,896,469)
38	**Impact to Operating Income**	$ (12,277,850)	$ 138,621	$ (12,139,230)

Notes and Sources

Exhibit 53 - Bates page 34 (Laflamme & Mullinax Supplemental Testimony)
Column A, Line 1: Attachment DBS/DSD-2, Schedule RR-EN-3-2 (Revised 11/21/17)
Column B, Line 3 Calculation
Average Vacancies

As of 1/1/16 (Staff Tech 3-13)	3.00
As of 11/1/17 (Staff Tech 3-13)	4.00
Average vacancies	3.50

Column B, Line 4: Calculation

Total Salaries and Wages (Att DBS/DSD-2, Sch RR-EN-3-2 Rev 11/21/17)	$ 29,788,526
Number of Employees Att DBS/DSD-2, Sch RR-EN-3-2 Rev 11/21/17)	310
Average Salaries and Wages per position	$ 96,092

Column A, Lines 7 and 9: Attachment DBS/DSD-2, Schedule RR-EN-3-2 (Revised 11/21/17)
Column A, Lines 12-18: Attachment DBS-DSD-2. Schedule RR-EN-3-3 (Revised 11/21/17)
Column A, Lines 20-30: Attachment DBS-DSD-2, Schedule RR-EN-3-4 (Revised 11/21/17)

Salaries and Wages to EN OpEx	(172,671)
Health Care and 401(k) Match to EN OpEx	(37,162)
Adjustment to Carryforward to Schedule 3	(209,833)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 7
Adjust Revenue to Year-End Customer Count

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Operating Revenue	$ 83,244,364	$ 929,551	$ 84,173,915
2	NH Income Tax	8.20%	0.00%	8.20%
3	Effect on NH income tax expense	$ 6,826,038	$ 76,223	$ 6,902,261
4	Federal Taxable	$ 76,418,326		$ 77,271,654
5	Federal Income Tax Rate	34%	0%	34%
6	Effect on Federal income tax expense	$ 25,982,231	$ 290,131	$ 26,272,362
7	Total Taxes	$ 32,808,269	$ 366,354	$ 33,174,623
8	**Impact to Operating Income**	$ 50,436,095	$ 563,197	$ 50,999,292

Notes and Sources
Exhibit 53 - Bates page 39 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 8
Remove Severance Associated with Resignations

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Payroll - Severance	$ 144,130	$ (78,181)	$ 65,949
2	Payroll Tax Rate (%)	10.98%		10.98%
3	Payroll Taxes	15,826	$ (8,585)	7,242
4	Total Severance Payroll and Payroll Taxes	$ 159,956	$ (86,766)	$ 73,191
5	NH Income Tax	8.20%	0.00%	8.20%
6	Effect on NH income tax expense	$ (13,116)	$ 7,114	$ (6,002)
7	Federal Taxable	$ 146,840		$ 67,189
8	Federal Income Tax Rate	34%	0.00%	34%
9	Effect on Federal income tax expense	$ (49,926)	$ 27,082	$ (22,844)
10	Total Taxes	$ (63,042)	$ 34,196	$ (28,846)
11	**Impact to Operating Income**	$ (96,914)	$ 52,570	$ (44,345)

Notes and Sources
Exhibit 53 - Bates page 41 (Laflamme & Mullinax Supplemental Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 9
Remove Keene Production Cost

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Keene Production Costs	$ 46,752	$ (46,752)	$ -
2	NH Income Tax	8.20%	0.00%	8.20%
3	Effect on NH income tax expense	$ (3,834)	$ 3,834	$ -
4	Federal Taxable	$ 42,918		$ -
5	Federal Income Tax Rate	34%	0.00%	34%
6	Effect on Federal income tax expense	$ (14,592)	$ 14,592	$ -
7	Total Taxes	$ (18,426)	$ 18,426	$ -
8	**Impact to Operating Income**	$ (28,326)	$ 28,326	$ -

Notes and Sources

Staff Tech 1-1: Exhibit 53 - Bates page 74 (Laflamme & Mullinax Supplemental Testimony)
Column A: Response to Staff Tech 1-1, Schedule RR-K-3-5
Schedule RR-K-5: Exhibit 3 - Bates page 63 (Simek & Dane Testimony)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Liberty Utilities (EnergyNorth and Keene)
Adjustment 10
Interest Synchronization

Line	Description	Company Proposed (A)	Adjustment (B)	Approved Amount (C)
1	Rate Base	$ 252,009,027	(7,619,599)	244,389,428
2	Interest Component of Rate of Return	2.21%		2.22%
3	Interest Attributable to Rate Base	5,569,399		5,425,445
4	NH Income Tax	8.20%	0.0%	8.20%
5	Effect on NH income tax expense	$ (456,691)	$ 11,805	$ (444,886)
6	Federal Taxable	$ 5,112,708		$ 4,980,559
7	Federal Income Tax Rate	34%	0.0%	34%
8	Effect on Federal income tax expense	$ (1,738,321)	$ 44,931	$ (1,693,390)
9	Total Taxes	$ (2,195,012)	$ 56,736	$ (2,138,276)
10	**Impact to Operating Income**	$ 2,195,012	$ (56,736)	$ 2,138,276

Notes and Sources

Column A and C, Line 2: Schedule 2 (see below)

	(A)	(C)
Long-Term Debt	2.21%	2.20%
Short-Term Debt	-	0.02%
	2.21%	2.22%

Commission
Revenue Requirement for iNATGAS Investment
Computation of Revenue Requirement Using Projected with AFUDC & Actual Capital Investment

		Projected	Actual	
Capital Investment		**Projected**	**Actual**	
Year of Operation		**1**	**1**	
Calendar Year		**2017**	**2017**	
Investment				
Compressors		1,000,000	1,100,000	
Piping, meter set, survey, etc		865,000	3,080,084	
Land (pro-rated)		200,000	200,000	
Contingency (Projected)		180,000	-	
AFUDC (Projected - Exhibit 51)		51,307	435,510	
Total Amount		2,296,307	4,815,594	
Deferred Tax Calculation				
Annual Tax Depreciation (no bonus in 2014)	MACRS 15 year	104,815	230,780	
Annual Book Depreciation (30-yr prop)	3.33%	69,877	160,520	
Annual Book/Tax Timer		34,938	70,260	
Book/Tax Timer		34,938	70,260	
Effective Tax Rate		39.41%	39.41%	
Deferred Tax Reserve		13,720	27,640	
Rate Base Calculation				
Plant In Service		2,296,307	4,815,594	
Accumulated Depreciation		(69,877)	(160,520)	
Net Plant in Service		2,226,430	4,655,074	
Deferred Tax Reserve		(13,720)	(27,640)	
Year End Rate Base		2,212,710	4,627,434	
Revenue Requirement Calculation				
Year End Rate Base		2,212,710	4,627,434	
Pre-Tax ROR		9.78%	9.78%	
Return and Income Taxes		216,403	452,563	
Book Depreciation - annual		69,877	160,520	
Property Taxes *	3.03%	67,461	141,049	
Annual Revenue Requirement		353,741	754,132	
Revenue at Minimum Take-or-Pay		192,600	192,600	
Revenue Deficiency		161,141	561,532	
Commission Proforma Adjustment for iNATGAS Revenue Requirement (Projected minus Actual)				**(400,391)**

Staff Proposed Capital Structure/ROR

	Ratio	Rate	Weighted Rate	Tax Rate	Pre Tax
Long Term Debt	49.85%	4.42%	2.20%		2.20%
Short Term Debt	0.95%	2.49%	0.02%		0.02%
Common Equity	49.21%	9.30%	4.58%	39.41%	7.55%
	100.01%		6.80%		9.78%

* Property tax rate reflects actual calendar year 2016 ratio of municipal tax expense to average net plant in service

DG 17-048
Impact of Tax Act

	Description	
1	Permanent rate increase	10,300,000
2	Original gross-up	1.6504
3	Increase before gross-up (line 1 * line 2)	6,240,911
4	Gross-up with new tax rates	1.3789
5	Revised Gross-up increase (line 3 * line 4)	8,605,593
6	Difference in Gross-up (line 5 - line 1)	(1,694,407)
7	Excess DIT ($27,321,620 /39.05 years)*	(699,657)
8	Total annual amount to return to customers (line 6 + line 7)	(2,394,065)

* Revaluing the existind deferred tax assets and liabilities at the lower tax rates resulted in a net amount of excess deferred tax liaiblity of $27,321,620 which will be amortized and returned to customers over the average remaining life of the underlying assets which is 39.05 years.

Notes & Source:
Exhibit 29 - Settlement Agreement, Attachment E (Bates page 23)

NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

Appendix 4
Page 1 of 1
DG 17-048

Liberty Utilities
2018 Step Adjustment
Settlement Step Increase adjusted for ROR, current tax rates, legal & degradation fees

Line	Description	Misc. Intangible Plant	LNG Plant	Mains	Station Equipment	General-Structures	Mains	Meas. & Reg. Station Equip.	Services	Meters	Structures and Improvements	Office Equipment	Vehicles	Stores Equipment	Tools	Total
	FERC Account	*303*	*320*	*367*	*369*	*375*	*376*	*378*	*380*	*381*	*390*	*391*	*392*	*394*	*394*	
1	Capital Spending - EnergyNorth	$ 2,105,141	$ 2,020,000	$14,414,334	$ 300,000	$ 1,215,000	$ 300,000	$ 325,000	$ 1,115,000	$ 1,600,000	$ 1,156,662	$ 760,384	$ 1,978,000	$ -	$ 175,000	$ 27,464,521
2	Capital Spending - Keene	$ 25,000		$ 236,000				$ 55,000	$ 50,000	$ 10,000		$ 65,000	$ 45,000	$ 4,000		$ 490,000
3	Capital Spending - Total	$ 2,130,141	$ 2,020,000	$14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$ 1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
	Deferred Tax Calculation															
4	Tax Method	MACRS15	MACRS20	MACRS20	MACRS20	MACRS39	MACRS20	MACRS20	MACRS20	MACRS20	MACRS39	MACRS7	MACRS5	MACRS7	MACRS7	
5	Tax Depreciation Rate	5.00%	3.75%	3.75%	3.75%	1.28%	3.75%	3.75%	3.75%	3.75%	1.28%	14.29%	20.00%	14.29%	14.29%	
6	Bonus Depreciation @ 0.00%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Tax Basis	$ 2,130,141	$ 2,020,000	$ 14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$ 1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
8	MACRS Depreciation	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	$ 1,450,946
9	Tax Depreciation - Federal	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	$ 1,450,946
10	Tax Depreciation - State	$ 106,507	$ 75,750	$ 549,388	$ 11,250	$ 15,577	$ 11,250	$ 14,250	$ 43,688	$ 60,375	$ 14,829	$ 117,912	$ 404,600	$ 571	$ 25,000	
11	Book Depreciation Rate	16.13%	2.86%	1.92%	2.86%	2.86%	1.92%	2.86%	3.55%	3.03%	3.33%	5.28%	20.00%	3.33%	5.26%	
12	Book Depreciation	$ 343,592	$ 57,772	$ 281,286	$ 8,580	$ 34,749	$ 5,760	$ 10,868	$ 41,358	$ 48,783	$ 38,517	$ 43,580	$ 404,600	$ 133	$ 9,205	$ 1,328,783
13	Tax over (under) Book - Federal	$ (237,085)	$ 17,978	$ 268,101	$ 2,670	$ (19,172)	$ 5,490	$ 3,382	$ 2,330	$ 11,592	$ (23,688)	$ 74,332	$ -	$ 438	$ 15,795	$ 122,163
14	Tax over (under) Book - State	(237,085)	17,978	268,101	2,670	(19,172)	5,490	3,382	2,330	11,592	(23,688)	74,332	0	438	15,795	122,163
15	Deferred Taxes - Federal @ 21.00%	(49,788)	3,775	56,301	561	(4,026)	1,153	710	489	2,434	(4,974)	15,610	0	92	3,317	25,654
16	Deferred Taxes - State @ 7.90%	(18,730)	1,420	21,180	211	(1,515)	434	267	184	916	(1,871)	5,872	0	35	1,248	9,651
17	Deferred Tax Balance @ 27.24%	$ (68,517)	$ 5,196	$ 77,481	$ 772	$ (5,541)	$ 1,587	$ 977	$ 673	$ 3,350	$ (6,846)	$ 21,482	$ -	$ 127	$ 4,565	$ 35,305
18	Rate Base Calculation															
19	Plant in Service	$ 2,130,141	$ 2,020,000	$14,650,334	$ 300,000	$ 1,215,000	$ 300,000	$ 380,000	$ 1,165,000	$ 1,610,000	$ 1,156,662	$ 825,384	$ 2,023,000	$ 4,000	$ 175,000	$ 27,954,521
20	Accumulated Depreciation	(343,592)	(57,772)	(281,286)	(8,580)	(34,749)	(5,760)	(10,868)	(41,358)	(48,783)	(38,517)	(43,580)	(404,600)	(133)	(9,205)	(1,328,783)
21	Deferred Tax Balance	68,517	(5,196)	(77,481)	(772)	5,541	(1,587)	(977)	(673)	(3,350)	6,846	(21,482)	0	(127)	(4,565)	(35,305)
22	**Rate Base**	$ 1,855,067	$ 1,957,032	$14,291,566	$ 290,648	$ 1,185,792	$ 292,653	$ 368,155	$ 1,122,969	$ 1,557,867	$ 1,124,991	$ 760,322	$ 1,618,400	$ 3,740	$ 161,230	$ 26,590,433
23	Revenue Requirement Calculation															
24	Return on Rate Base @ 8.51%	$ 157,934	$ 166,615	$ 1,216,735	$ 24,745	$ 100,954	$ 24,915	$ 31,343	$ 95,606	$ 132,631	$ 95,778	$ 64,731	$ 137,785	$ 318	$ 13,727	$ 2,263,818
25	Depreciation Expense	343,592	57,772	281,286	8,580	34,749	5,760	10,868	41,358	48,783	38,517	43,580	404,600	133	9,205	1,328,783
26	EN Property Tax @ 2.06%		41,512	296,222	6,165	24,969	6,165	6,679			23,770					405,483
27	Keene Property Tax @ 4.17%			9,838				2,293	2,084	417						14,633
28	Keene Insurance @ 4.25%			10,032				2,338	2,125	425		2,763	1,913	170		19,767
29	EN Insurance @ 0.20%		3,983	28,421	592	2,396	592	641	2,198	3,155	2,281	1,499	3,900	0	345	50,001
30	**Annual Revenue Requirement**	$ 501,526	$ 269,882	$ 1,842,535	$ 40,081	$ 163,068	$ 37,432	$ 54,162	$ 143,372	$ 185,411	$ 160,345	$ 112,574	$ 548,198	$ 622	$ 23,277	$ 4,082,483
31	**Adjustments**															
32	**Updated Pension and OPEB Costs (Staff Tech 3-15)**															$ 419,583
33	**2017 Legal Fees (Staff Corrected - Exhibit 54)**															$ 57,506
34	**2017 Degradation Fees (Staff Correct - Exhibit 54)**															$ 9,303
35	**Cast Iron/Bare Steel - 2016 Carry Over Adjustment (Settlement Agreement - Exhibit 29, Bates page 8)**															$ 5,375
36	**Cast Iron/Bare Steel - 2017 Carry Over Adjustment (Settlement Agreement - Exhibit 29, Bates page 8)**															$ 155,703
37	**Total Adjustments**															$ 647,470
38	**Total (Adjusted) Annual Revenue Requirement**															$ 4,729,953

Source: Exhibit 29 - Bates page 18 (Settlement Agreement)

DG 17-048
Reconciliation of Temporary & Permanent Rates
Recoupment of Under Recovery

	Description		
1	Permanent rate increase	$8,060,117	
2	Temporary Rate Increase	$6,750,000	
3	Annual Recoupment (line 1 - line 2)		$1,310,117
4	Test Year Weatehr Normalized Sales		159,761,663
5	Recoupment per Therm Surcharge (line 3 / line 4)		$0.0082
6	Times Actual/Estimated July 1, 2017 thru April 30, 2018 Sales		161,741,745
7	Recoupment (line 5 * line 6)		$1,326,355

Source:
Exhibit 29 - Settlement Agreement, Attachment C (Bates page 20)

DG 17-048
Depreciation Accrual Rates

FERC ACCOUNT NUMBER	DESCRIPTION	ASL	NET SALVAGE %	WHOLE LIFE DEPREC. ACCRUAL RATES (Note 1)
303.00	CAPITALIZED SOFTWARE	6.2	0	16.13
	PRODUCTION PLANT			
305.00	STRUCTURES AND IMPROVEMENTS	35.0	0	2.86
311.00	LP GAS EQUIPMENT	35.0	0	2.86
320.00	OTHER EQUIPMENT-LNG	35.0	0	2.86
320.10	OTHER EQUIPMENT-PRODUCTION	35.0	0	2.86
	STORAGE PLANT			
361.00	STRUCTURES AND IMPROVEMENTS-LNG	35.0	0	2.86
363.50	OTHER EQUIPMENT-LNG	35.0	0	2.86
	TRANSMISSION PLANT (Note 2)			
366.20	STRUCTURES AND IMPROVEMENTS (reclass to 375)	35.0	0	2.86
366.30	STRUCTURES AND IMPROVEMENTS-OTHER (reclass to 375)	35.0	0	2.86
367.00	MAINS (reclass to 376)	60.0	-15	1.92
369.00	MEASURING AND REGULATING STATION EQUIP. (reclass to 3	35.0	0	2.86
	DISTRIBUTION PLANT			
380.00	SERVICES	45.0	-60	3.55
381.00	METERS	32.0	0	3.13
381.10	METERS-INSTRUMENT	32.0	0	3.13
381.20	METERS-ERTS	15.0	0	6.67
382.00	METER INSTALLATIONS	32.0	0	3.13
387.00	OTHER EQUIPMENT	19.0	0	5.26
	GENERAL PLANT			
390.00	STRUCTURES AND IMPROVEMENTS	35.0	0	2.86
391.00	OFFICE FURNITURE AND EQUIP.	18.0	5	5.28
391.10	OFFICE FURNITURE AND EQUIP.-COMPUTERS	10.0	0	10.00
391.20	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP.	5.0	0	20.00
393.00	STORES EQUIPMENT	30.0	0	3.33
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	19.0	0	5.26
394.10	TOOLS, SHOP & GARAGE EQUIPMENT-CNG STATION	19.0	0	5.26
397.00	COMMUNICATION EQUIPMENT	10.0	0	10.00
398.00	MISCELLANEOUS GENERAL EQUIPMENT	15.0	0	6.67

Note 1: The calculation of deprecation accrual rates is based on the whole-life technique as follows:
1-(net salvage percent) divided by average service life

Note 2: Incorrectly classified as transmission plant, corrected through reclass as distribution plant.

Liberty Bill Impact Analysis - Residential Heating Customer

Cost of Gas Filing Methodology

Rates Effective May 1, 2019 - Estimate Based on Commission Order

Winter Season (Jan. - Apr., Nov. - Dec.) / Summer Season (May - Oct.)

Residential Heating (R3)

Rates Effective May 1, 2018		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		51	90	117	141	130	89	618	51	25	16	14	14	22	142	760
Winter:																
Cust. Chg	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28								
Headblock	$0.5564	$28.33	$50.08	$55.64	$55.64	$55.64	$49.25	$294.56								
Tailblock	$0.5564	$0.00	$0.00	$9.67	$22.93	$16.53	$0.00	$49.13								
HB Threshold	100															
Summer:																
Cust. Chg	$14.88								$14.88	$14.88	$14.88	$14.88	$14.88	$14.88	$89.28	$178.56
Headblock	$0.5564								$11.13	$11.13	$9.01	$7.84	$7.82	$11.13	$58.06	$352.62
Tailblock	$0.5564								$17.20	$2.99	$0.00	$0.00	$0.00	$0.93	$21.13	$70.26
HB Threshold	20															
Total Base Rate Amount		$43.21	$64.96	$80.19	$93.45	$87.05	$64.13	$432.98	$43.21	$29.00	$23.89	$22.72	$22.70	$26.94	$168.46	$601.44
COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7382								
COG amount - Winter		$32.81	$58.01	$75.66	$113.76	$104.50	$71.32	$456.05								
COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.6587
COG amount - Summer									$15.95	$7.95	$5.07	$4.42	$4.40	$6.79	$44.59	$500.64
LDAC	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945
LDAC amount		$4.81	$8.50	$11.09	$13.34	$12.25	$8.36	$58.36	$4.81	$2.40	$1.53	$1.33	$1.33	$2.05	$13.45	$71.81
Total Bill		$80.83	$131.47	$166.94	$220.55	$203.80	$143.81	$947.39	$63.97	$39.34	$30.50	$28.47	$28.43	$35.78	$226.50	$1,173.89

Winter Season (Jan. - Apr., Nov. - Dec.) / Summer Season (May - Oct.)

Residential Heating (R3)

Rate Prior to Temporary Rates		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		51	90	117	141	130	89	618	51	25	16	14	14	22	142	760
Winter:																
Cust. Chg	$22.10	$22.10	$22.10	$22.10	$22.10	$22.10	$22.10	$132.60								
Headblock	$0.3495	$17.79	$31.46	$34.95	$34.95	$34.95	$30.94	$185.04								
Tailblock	$0.2892	$0.00	$0.00	$5.03	$11.92	$8.59	$0.00	$25.54								
HB Threshold	100															
Summer:																
Cust. Chg	$22.10								$22.10	$22.10	$22.10	$22.10	$22.10	$22.10	$132.60	$265.20
Headblock	$0.3495								$6.99	$6.99	$5.66	$4.93	$4.91	$6.99	$36.47	$221.51
Tailblock	$0.2892								$8.94	$1.55	$0.00	$0.00	$0.00	$0.48	$10.98	$36.52
HB Threshold	20															
Total Base Rate Amount		$39.89	$53.56	$62.08	$68.97	$65.64	$53.04	$343.18	$38.03	$30.64	$27.76	$27.03	$27.01	$29.57	$180.05	$523.23
COG Rate - (Winter)		$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7382								
COG amount - Winter		$32.81	$58.01	$75.66	$113.76	$104.50	$71.32	$456.05								
COG Rate - (Summer)									$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.3133	$0.6587
COG amount - Summer									$15.95	$7.95	$5.07	$4.42	$4.40	$6.79	$44.59	$500.64
LDAC	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856
LDAC amount		$4.36	$7.70	$10.05	$12.09	$11.10	$7.58	$52.88	$4.36	$2.17	$1.39	$1.21	$1.20	$1.86	$12.18	$65.06
Total Bill		$77.07	$119.27	$147.78	$194.82	$181.24	$131.93	$852.11	$58.34	$40.77	$34.22	$32.65	$32.62	$38.22	$236.82	$1,088.94

DIFFERENCE	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill	$3.76	$12.20	$19.15	$25.73	$22.56	$11.88	$95.28	$5.63	($1.42)	($3.73)	($4.18)	($4.19)	($2.44)	($10.33)	$84.95
% Change	4.88%	10.23%	12.96%	13.21%	12.44%	9.00%	11.18%	9.65%	-3.49%	-10.89%	-12.80%	-12.84%	-6.39%	-4.36%	7.80%
Base Rate	$3.31	$11.40	$18.11	$24.48	$21.40	$11.09	$89.80	$5.18	($1.65)	($3.87)	($4.30)	($4.31)	($2.63)	($11.59)	$78.21
% Change	8.30%	21.28%	29.18%	35.49%	32.61%	20.91%	26.17%	13.61%	-5.37%	-13.94%	-15.93%	-15.96%	-8.91%	-6.44%	14.95%
COG & LDAC	$0.45	$0.80	$1.04	$1.25	$1.15	$0.79	$5.48	$0.45	$0.23	$0.14	$0.13	$0.12	$0.19	$1.26	$6.75
% Change	1.22%	1.22%	1.22%	1.00%	1.00%	1.00%	1.08%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	1.19%

Liberty Bill Impact Analysis - KEENE Residential Heating Customer

Cost of Gas Filing Methodology

Rates Effective May 1, 2019 - Estimate Based on Commission Order

Winter Season (Jan. - Apr., Nov. - Dec.) / Summer Season (May - Oct.)

Keene Residential to EnergyNorth Residential Heating (R3)

Rates Effective May 1, 2018		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		40	76	104	110	117	87	534	57	29	17	17	22	17	159	693
(Average per DG 18-052 Keene Summer COG)																
Winter:																
Cust. Chg	$14 88	$14 88	$14 88	$14 88	$14 88	$14 88	$14 88	$89.28								
Headblock	$0 5564	$22 25	$42 28	$55 64	$55 64	$55 64	$48.40	$279 85								
Tailblock	$0.5564	$0 00	$0 00	$2 23	$5 56	$9.46	$0.00	$17 25								
HB Threshold	100															
Summer:																
Cust. Chg	$14 88								$14 88	$14 88	$14 88	$14 88	$14 88	$14.88	$89 28	$178.56
Headblock	$0 5564								$11 13	$11 13	$9 46	$9 46	$11.13	$9 46	$61 76	$341 61
Tailblock	$0 5564								$20 59	$5 01	$0 00	$0.00	$1 11	$0 00	$26.71	$43 95
HB Threshold	20															
Total Base Rate Amount		$37 13	$57 16	$72 74	$76.08	$79 97	$63.28	$386 38	$46 59	$31 01	$24 34	$24 34	$27 12	$24 34	$177.74	$564 12
COG Rate - (Winter)		$1 2533	$1 2533	$1 3008	$1 5666	$1 5666	$1 5666	$1 4468								
COG amount - Winter		$50 13	$95 25	$135 28	$172.33	$183 29	$136.29	$772.58								
COG Rate - (Summer)									$0 6281	$0.6281	$0 6866	$0 7766	$0 7851	$0 7851	$0 6887	$1.2729
COG amount - Summer									$35 80	$18.21	$11 67	$13 20	$17 27	$13 35	$109 51	$882 09
LDAC	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0 0945	$0.0945	$0 0945	$0 0945	$0 0945	$0.0945
LDAC amount		$3.78	$7 18	$9 83	$10 39	$11.05	$8 22	$50 45	$5 39	$2 74	$1 61	$1 61	$2 08	$1 61	$15.02	$65 47
Total Bill		$91.05	$159.59	$217.85	$258.80	$274.32	$207.80	$1,209.41	$87.78	$51.97	$37.62	$39.15	$46.47	$39.29	$302.27	$1,511.68

Winter Season (Jan. - Apr., Nov. - Dec.) / Summer Season (May - Oct.)

Keene Residential to EnergyNorth Residential Heating (R3)

CURRENT (Temporary Rates not Requested)		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Average Usage (Therms)		40	76	104	110	117	87	534	57	29	17	17	22	17	159	693
(Average per DG 18-052 Keene Summer COG)																
Winter:																
Cust. Chg	$9 00	$9.00	$9 00	$9 00	$9 00	$9 00	$9 00	$54 00								
Block 1	$1 1522	$46 09	$87 57	$92 18	$92 18	$92 18	$92 18	$502.36								
Block 2	$0.9442	$0.00	$0 00	$22 66	$28 33	$34.94	$6 61	$92 53								
Block 3	$0 7946	$0.00	$0 00	$0 00	$0 00	$0 00	$0.00	$0.00								
BL1 Threshold	80															
BL2 Threshold	120															
Summer:																
Cust. Chg	$9 00								$9 00	$9 00	$9.00	$9.00	$9 00	$9 00	$54 00	$108.00
Block 1									$0.00	$0 00	$0 00	$0 00	$0.00	$0 00	$0.00	$502 36
Block 2	$0 9442								$0 00	$0.00	$0 00	$0.00	$0 00	$0 00	$0.00	$92.53
Block 3	$0 7946								$0 00	$0.00	$0.00	$0 00	$0 00	$0 00	$0.00	$0.00
BL1 Threshold	80															
BL2 Threshold	120															
Total Base Rate Amount		$55 09	$96 57	$123 84	$129 50	$136 11	$107 79	$648.89	$9 00	$9.00	$9 00	$9.00	$9.00	$9 00	$54 00	$702 89
COG Rate - (Winter)		$1.2533	$1 2533	$1 3008	$1 5666	$1 5666	$1 5666	$1 4468								
COG amount - Winter		$50 13	$95 25	$135 28	$172 33	$183.29	$136 29	$772.58								
COG Rate - (Summer)									$0 6281	$0 6281	$0 6866	$0.7766	$0.7851	$0.7851	$0.6887	$1 2729
COG amount - Summer									$35.80	$18 21	$11 67	$13 20	$17.27	$13.35	$109.51	$882.09
LDAC	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	$0 0000	0 0000	$0 0000	$0.0000	$0 0000	$0 0000	$0 0000	$0.0000	$0.0000	$0.0000
LDAC amount		$0.00	$0 00	$0 00	$0.00	$0 00	$0.00	$0 00	$0 00	$0 00	$0 00	$0 00	$0.00	$0 00	$0.00	$0 00
Total Bill		$105.22	$191.82	$259.12	$301.83	$319.40	$244.08	$1,421.47	$44.80	$27.21	$20.67	$22.20	$26.27	$22.35	$163.51	$1,584.98

DIFFERENCE:

	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer	Total 2017/18
Total Bill	($14.17)	($32.22)	($41.27)	($43.03)	($45.08)	($36.28)	($212.06)	$42.98	$24.75	$16.94	$16.94	$20.20	$16.94	$138.76	($73.30)
% Change	-13.47%	-16.80%	-15.93%	-14.26%	-14.11%	-14.87%	-14.92%	95.93%	90.96%	81.97%	76.32%	76.88%	75.82%	84.87%	-4.62%
Base Rate	($17 95)	($39 40)	($51 10)	($53.42)	($56 14)	($44 50)	($262 51)	$37 59	$22.01	$15 34	$15.34	$18.12	$15.34	$123.74	($138.77)
% Change	-32.59%	-40 80%	-41 26%	-41 25%	-41 24%	-41 29%	-40.46%	417.70%	244 61%	170.42%	170.42%	201.33%	170.42%	229.15%	-19.74%
COG & LDAC	$3.78	$7 18	$9 83	$10 39	$11 05	$8 22	$50 45	$5 39	$2.74	$1 61	$1.61	$2.08	$1 61	$15.02	$65 47
% Change	7.54%	7.54%	7 26%	6 03%	6.03%	6 03%	6.53%	15.04%	15.04%	13.76%	12.17%	12.03%	12.03%	13.72%	7.42%

(1) Residential Heating Typical Usage: Single family detached home using gas for heat, hot water and cooking (from DG 18-052 Summer COG)

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

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Docket #: 17-048-1 Printed: April 26, 2018

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**