NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

CHRISTOPHER J. GOULDING

AND

DANIEL T. NAWAZELSKI

EXHIBIT CGDN-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Christopher J. Goulding, and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

My name is Daniel T. Nawazelski, and my business address is the same as Mr. Goulding's.

Q. Mr. Goulding, what is your position and what are your responsibilities?

A. I am the Director of Rates and Revenue Requirements for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation ("Unitil Corp" that provides managerial, financial, regulatory and engineering services to Unitil Corp's utility subsidiaries including Northern Utilities, Inc. ("Northern" or the "Company"). My responsibilities include all rate and regulatory filings related to the financial requirements of Northern and Unitil Corp's other subsidiaries.

Q. Please describe your business and educational background.

A. In 2000 I was hired by NSTAR Electric & Gas Company ("NSTAR", now Eversource Energy) and held various positions with increasing responsibilities in Accounting, Corporate Finance and Regulatory. I was hired by Unitil Service in early 2019 to perform my current job responsibilities. I earned a Bachelor of Science degree in Business Administration from Northeastern University in 2000 and a Master's in Business Administration from Boston College in 2009.

Q. Have you previously testified before this Commission or other regulatory agencies?

A. Yes, I have testified before the New Hampshire Public Utilities Commission (the "Commission") on various financial, ratemaking and utility regulation matters, including utility cost of service and revenue requirements analysis. I have also testified before the Maine Public Utilities Commission and Massachusetts Department of Public Utilities on similar matters on several occasions.

Q. Mr. Nawazelski, what is your position and what are your responsibilities?

A. I am the Manager of Revenue Requirements for Unitil Service. In this capacity I am responsible for the preparation and presentation of distribution rate cases and in support of other various regulatory proceedings.

Q. Please describe your business and educational background.

A. I began working for Unitil Service in June of 2012 as an Associate Financial Analyst, progressing to the role of Manager of Revenue Requirements in 2021. I earned a Bachelor of Science degree in Business with a concentration in Finance and Operations Management from the University of Massachusetts, Amherst in May of 2012.

Q. Have you previously testified before this Commission or other regulatory agencies?

A. Yes, I have testified before the Commission on various financial, ratemaking and utility regulation matters. I have also testified before the Maine Public Utilities

Commission and Massachusetts Department of Public Utilities on similar matters on several occasions.

II. SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to present and support Northern in its request for a permanent increase in distribution base rates based on 2020 test year revenues and expenses and year-end rate base with pro forma adjustments for known and measurable changes consistent with Commission precedent. Also, as introduced in the prefiled testimony of Company witness Mr. Robert Hevert, we describe the process and mechanics of the Company's requested multi-year rate plan (the "2021 Rate Plan"). Next, we describe and support the Company's request for a temporary increase in distribution base rates, which would be subject to reconciliation based on the difference between permanent and temporary rates. We also discuss the Company's other regulatory proposals and considerations regarding waived late payment charges, special contract revenues, the treatment of certain mains extensions projects and an update to the Company's expansion in Epping, New Hampshire. Next, we explain the transition to decoupling from the current lost revenue recovery mechanism. Finally, we provide proposed tariff changes and estimated rate case costs and proposed recovery of those costs.

Q. Please summarize the Company's conclusions with respect to its revenue requirement.

A. Based on test year results, as adjusted for known and measurable changes, for the twelve months ended December 31, 2020, the Company has determined the need to increase its base distribution revenues by $7,782,950 or approximately 8.1 percent over the Company's total base revenue under present rates after accounting for changes to other reconciling mechanisms. These changes roll certain items, such as lost base revenue and regulatory assessments, currently collected through reconciling mechanisms reimbursement into base distribution rates. The request is founded on the need for achieving, after payment of all operating expenses, taxes and other charges, a weighted average cost of capital of 7.75 percent that includes a return of equity ("ROE") of 10.30 percent.

Q. Please elaborate on the changes in existing reconciling mechanisms described above.

A. The Company currently collects costs for lost base revenue and regulatory assessments through reconciling mechanisms. The proposed adjustments in the instant proceeding move the recovery of these costs through reconciling mechanism to base rates. While these adjustments reflect increases to base rates, it does not reflect any additional impact to ratepayers or additional revenue to the Company. Rather, it simply moves recovery of the costs from the reconciling mechanisms to base rates. Each of these proposed adjustments is described in greater detail below with the applicable reconciling mechanisms that are impacted. The movement of these costs results in a net base revenue increase of $7,307,632 as summarized in Table 1 below.

Table 1: Net Revenue Deficiency Increase

Description	Reference	Amount
Revenue Deficiency	Schedule RevReq-1, Line 7	$ 7,782,950
Cost Recovery Movement		
Lost Base Revenue	RevReq Workpaper – Flowthrough Detail	$ (359,089)
Regulatory Assessments	Schedule RevReq-3-9, Line 3	$ (116,230)
Net Revenue Deficiency		$ 7,307,632

III. DEVELOPMENT OF THE DISTRIBUTION REVENUE REQUIREMENT

A. METHOD OF ANALYSIS

Q. What approach did you use to perform the revenue requirement analysis?

A. To perform the revenue requirement analysis, we determined the cost of service, using a test-year approach as pro formed and adjusted for material, known and measurable changes. We then compared the cost of service to test year revenues (as adjusted) to derive a revenue deficiency, and the corresponding revenue requirement that Northern would have to receive on a test year basis to make up this deficiency. The deficiency is then increased for state and federal income taxes to determine the revenue deficiency.

Q. What was the test year for computing the Company's cost of service?

A. The test year is the twelve-month period ending December 31, 2020, which is the most recent calendar year for which data is available. Calendar year 2020 data is also readily verifiable to the most recent annual reports submitted by Northern.

Q. What standards were employed to determine the pro forma adjustments?

A. All adjustments to the test year cost of service are based upon known and measurable changes to revenues and expenses, or upon changes that will become known and measurable during the course of this proceeding. As a practical matter, the Company has limited all pro forma adjustments to those that will be known and measurable through August 1, 2022, which is the date permanent rates are expected to go into effect for this proceeding.

Q. Why are these standards important?

A. The rates established in this proceeding should provide Northern with sufficient revenues to continue to ensure safe, reliable and cost-effective delivery service for Northern customers and to provide a reasonable opportunity for Northern to earn its authorized rate of return. Northern has a reasonable opportunity to earn its allowed rate of return when the proposed rates reflect, as closely as possible, the cost of service that Northern will actually experience when permanent rates are awarded.

Q. Have you followed the Commission's required format for presenting the calculation of the proposed revenue requirement?

A. Yes, to the best of our knowledge. We have followed the requirements as described in New Hampshire Code of Administrative Rules, Chapter Puc 1600 Tariffs and Special Contracts, Part Puc 1604 Full Rate Case Filing Requirements, Sections Puc 1604.06 through 1604.09. The Filing Requirement Schedules specified in Sections Puc 1604.06 and 1604.07 have been provided as "Filing

Requirement Schedules Pages 1-12." The Filing Requirement Schedules are a summary of the actual revenue requirement model which drives the underlying calculations of the revenue deficiency. This revenue requirement model will be referred to throughout the rest of our testimony as "RevReq" schedules. The Rate of Return Information specified in Section Puc 1604.08 has been provided in Schedules RevReq-6 through 6-7. The Adjustments to Test Year specified in Section Puc 1604.09 have been provided in Schedules RevReq-3 through 3-21.

Q. Has Northern filed other material as required by Part Puc 1604 Full Rate Case Filing Requirements?

A. Yes. The material required by Section Puc 1604.01, Contents of a Full Rate Case, has been provided with this filing as separate volumes of materials.

B. SUMMARY OF RESULTS

Q. Please summarize the results of your revenue requirement analysis.

A. In the current proceeding, the Company is requesting rate adjustments related to the Base Distribution function. As shown on Schedule RevReq-1, comparing the adjusted cost of service to the adjusted operating revenues derives the Base Distribution revenue deficiency for the test year of $7,782,950 based on an overall rate of return on rate base of 7.75 percent and known and measurable adjustments to test year revenues, expenses, and rate base.

Q. Please describe the test year operating income, as adjusted, and used to determine the revenue deficiency.

A. The revenue requirement schedules and workpapers for Northern in the test year are presented in Schedule RevReq-1 through RevReq-7 and Workpapers supporting the revenue requirement schedules. The pro forma operating income for Northern in the test year is presented in Schedule RevReq-2, pages 1 and 2. In page 1, the "per books" revenues, operating expenses and net operating income are set forth in column (2), labeled "Test Year 12 Months Ended 12/31/2020." Column (3), labeled "Cost of Gas Excluding Prod. & OH.", contains test year revenue and operating expenses associated with the Company's cost of gas mechanism, excluding its allowance for production and related overhead. We will discuss the exclusion of production and related overhead in the next Q&A. Column (4), labeled "Other Flowthrough" contains revenue and operating expenses from the Company's non-base rate mechanisms including energy efficiency, environmental response costs, residential low income assistance, rate case costs, recoupment, lost base revenue and on-bill financing. Column (5), labeled "Test Year Distribution, Prod. & OH." reflects base revenues and expenses and is calculated by subtracting Columns (3) and (4) from Column (2). In page 2 of Schedule RevReq-2, the proposed normalizing adjustments are set forth in column (3), labeled "Pro Forma Adjustments." The pro forma adjustments are added to column (2), labeled "Test Year Distribution, Prod. & OH", to obtain the adjusted revenues and operating expenses in column (4), labeled "Test Year Distribution, Prod. & OH. Pro Forma." The pro forma operating income from column (4) is used to determine the operating income deficiency which is summarized in Schedule RevReq-1. The pro forma operating income from column (4) is used to determine the operating income deficiency which is summarized in Schedule RevReq-1. Schedule RevReq-1 calculates the income required by multiplying rate base by the rate of return. The pro forma operating income from column (4) Schedule RevReq-2, page 2 of 2 is then subtracted from the income required in Schedule RevReq-1 to obtain the operating income deficiency. This operating income deficiency is then grossed up for federal and state taxes to obtain the revenue deficiency as shown on Line 7 of Schedule RevReq-1.

Q. Please describe the exclusion of production and related overhead allowances in the cost of gas mechanism as shown in column (3) of page 1 of Schedule RevReq-2.

A. During the test year, the Company collected $1,057,890 for production and related overhead through the Company's cost of gas mechanism as shown in Workpaper – Cost of Gas. This revenue relates to the revenue requirement last approved for the Company's gas production facilities in Docket DG 17-070. Excluding this amount from column (3) causes it to be included as a component of revenues in column (5) of Schedule RevReq-2, page 1. This component of the revenue requirement is later functionalized as production-related by witnesses Ron Amen and John Taylor and appropriately assigned for recovery through the cost of gas mechanism consistent with the current ratemaking.

Q. Please describe the pro forma adjustments that are shown in column (3) of page 2 of Schedule RevReq-2.

A. As shown, we have made pro forma adjustments to the following areas:

- Revenue
- Operating and Maintenance Expenses
- Depreciation and Amortization
- Taxes Other than Income
- Federal and State Income Taxes
- Net Book Value, Accumulated Deferred Taxes & Cash Working Capital

These pro forma adjustments are detailed on Schedule RevReq-3 and on subsequent schedules as identified.

Q. Have you provided additional schedules that summarize the results of your revenue requirements analysis and support the rate change requested?

A. Yes, we have. Schedule RevReq-4 contains balance sheet and detailed plant and accumulated depreciation information. Schedule RevReq-5 contains all rate base components, including plant in service, accumulated depreciation, and deferred income taxes, as well as associated rate base related pro forma adjustments. Lastly, Schedule RevReq-6 provides the calculations showing the Company's requested return on rate base of 7.75 percent.

C. DISTRIBUTION REVENUE REQUIREMENT

I. TOTAL OPERATING REVENUES

Q. What adjustments were made to Total Operating Revenues?

A. We made the following adjustments to total operating revenues:

- Weather Normalization
- New Customer Revenue Annualization
- Residential Low Income
- Unbilled Revenue
- Non-Distribution Bad Debt
- Miscellaneous Revenue Adjustment
- Late Fees
- Billed Accuracy Adjustment
- Special Contract Customer Revenue

1. WEATHER NORMALIZATION

Q. Please explain the weather normalization adjustment.

A. The weather normalization adjustment normalizes the effect of actual weather experienced during the test year. Normal weather is based on 20-year historical average temperatures. In 2020, net temperatures were warmer than normal; therefore the test year operating revenues were lower than would occur under normal weather conditions. Schedule RevReq-3-1 provides for a pro forma adjustment to increase base distribution revenue by $1,994,374. This adjustment was calculated and supported in the testimony of Ron Amen and John Taylor.

2. NEW CUSTOMER REVENUE ANNUALIZATION

Q. Please explain the new customer revenue annualization adjustment.

A. The Company has adjusted test year operating revenues to annualize for sales growth associated with year-end customers. Schedule RevReq-3-2, Line 2 provides for a pro forma adjustment to increase base distribution revenue by $278,301. This adjustment was calculated and supported in the testimony of Ron Amen and John Taylor.

3. RESIDENTIAL LOW INCOME

Q. Please explain the residential low income adjustment.

A. We increased distribution revenues by $264,523 to reflect that residential low income costs are collected through a separate flow-through rate recovery mechanism, but should be attributed to the Company's cost of service. This adjustment is shown in Schedule RevReq-3-2, Line 4.

4. UNBILLED REVENUE

Q. Please explain the unbilled revenue adjustment.

A. The Company books unbilled revenue to account for the difference between the amount of gas delivered to customers during the test year and the amount billed to customers during the same period. Because the test year sales are based on weather-normalized sales, the accrual for the amount of unbilled sales was removed from the test year. This adjustment increases revenue by $294,543 as shown in Schedule RevReq-3-2, Line 6.

5. NON-DISTRIBUTION BAD DEBT

Q. Please explain the non-distribution bad debt adjustment.

A. Total revenues have been decreased by $97,468 to remove accrued revenue associated with non-distribution bad debt. A similar adjustment was made to decrease operating expenses by $97,468, which is the provision for non-distribution bad debt in operating expenses. These adjustments are summarized in Schedule RevReq-3-2, Lines 7-9. Overall, there is no impact on the revenue requirement since both the revenue and operating expenses are adjusted by the same amount.

6. MISCELLANEOUS REVENUE ADJUSTMENT

Q. Please explain the miscellaneous revenue adjustment.

A. The Company booked a miscellaneous revenue adjustment to clear remaining rate case expense and recoupment balances during the 2020 test year. To remove this nonrecurring entry we have increased total revenues by $4,788 as shown in Schedule RevReq-3-2, Line 11.

7. LATE FEE REVENUE

Q. Please explain the late fee revenue adjustment.

A. The Company has increased test year revenue by $40,013 as shown in Schedule RevReq-3-2, Lines 12-15, to normalize the late payment charge revenue to the 2019 level to account for the Governor and Commission order issued in March 2020 that prohibited the charging of customers late payment fee. The moratorium resulted in the Company collecting a non-representative level of late payment charge revenue in the test year.

Q. Is the Company proposing to recover the lost late payment charge revenues associated with the moratorium that prohibited the Company from collecting these revenues?

A. Yes, the details of the proposal are explained below in Section VI "Other Regulatory Proposals and Considerations".

8. BILLED ACCURACY ADJUSTMENT

Q. Please explain the billed accuracy adjustment.

A. The billed accuracy adjustment increases revenue by $367 and reflects the difference between what the Company booked in the test year versus what witnesses Ron Amen and John Taylor calculated using test year billing determinants and distribution rates. This adjustment is shown in Schedule RevReq-3-2, Lines 17.

9. SPECIAL CONTRACT CUSTOMER REVENUE

Q. Please explain the special contract customer revenue adjustment.

A. We increased total revenues by $17,968 as shown in Schedule RevReq-3-2, Lines 18-21 to reflect known and measurable special contract rate increases that occurred in December 2020 and March 2021. Test year billing determinants for these two customers were calculated at their respective 2021 special contract rates and then reduced by the customer's test year actual revenues to calculate the net revenue adjustment.

Q. Is the Company proposing anything else with respect to special contract revenue?

A. Yes. The Company is proposing to exclude special contract revenue from decoupling. The details of the proposal are explained below in Section VI "Other Regulatory Proposals and Considerations."

II. OPERATING & MAINTENANCE EXPENSES

Q. What is the amount of Northern's per books Operating & Maintenance Expense?

A. In the test year, Northern incurred $13,580,391 of Operating & Maintenance ("O&M") Expense related to Distribution and Production Related Overhead, as shown on Schedule RevReq-2, Page 2, Column 2, Lines 6 through 12.

Q. What adjustments were made to O&M Expenses?

A. Pro forma adjustments are included in the distribution cost of service for the following O&M Expenses:

- Production Expense
- Non-Distribution Bad Debt
- Distribution Bad Debt
- Payroll
- Medical & Dental Insurances
- Pension, Postemployment Benefits Other than Pension, Supplemental Executive Retirement Plan, 401K, and Deferred Compensation Plan Expense
- Property & Liability Insurance

- Commission Regulatory Assessment
- Dues and Subscriptions
- Pandemic Costs
- Severance
- Rent Expense
- Arrearage Management Program ("AMP") Implementation Cost
- Inflation Allowance

We will discuss each adjustment individually in the following section.

1. PRODUCTION EXPENSE

Q. Please explain the adjustment for production expense.

A. This adjustment allocates production facility operation and maintenance expenses between Northern Utilities' Maine (ME) and New Hampshire (NH) divisions by the Fixed Demand factor as filed in the Company's cost of gas filings. The Fixed Demand factor as of December 31, 2020 was 40.88% (NH) and 59.12% (ME). This allocation results in an increase of expense of $76,191 to the NH division as shown in Schedule RevReq 3-3.

2. PAYROLL

Q. What adjustment was made to payroll?

A. The payroll adjustment, as reflected on Schedule RevReq-3-4 Page 1, adjusts the test year payroll charged to O&M Expense for the following:

1. Annualization of the pay rate increases that have occurred during calendar year 2020 for the union employees;

2. The effect of pay rate increases that occurred on January 1, 2021 and will occur on September 6, 2021 and that are projected to occur on January 1, 2022 and September 6, 2022.

These adjustments have been made to the payroll for both Northern and Unitil Service. The 2022 wage increases are estimated for the purposes of this initial filing, but will be updated with actual results before the completion of this proceeding. Test year incentive compensation was booked to the target level so no adjustment is required. The pro forma increase to test year O&M payroll is $554,442 as shown on Schedule RevReq-3-4 Page 1, Column 6, Line 13. This adjustment is discussed in more detail in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

3. DISTRIBUTION BAD DEBT

Q. Please explain the adjustment of test year distribution bad debt expense.

A. The calculation of this adjustment is shown in Schedule RevReq-3-5. This adjustment was developed by first calculating a bad debt rate based on 2019 delivery net write-offs divided by 2019 delivery billed revenue. We then multiplied the bad debt rate by test year delivery revenue including the revenue requirement from Schedule RevReq-1, which establishes an uncollectible revenues amount. The uncollectible revenues amount is compared to test year delivery write-offs to produce the pro forma adjustment of $88,160.

Q. Why did the Company choose to use 2019 delivery net write-offs and 2019 delivery billed revenue?

A. The Company is proposing to use the 2019 delivery net write off percent because the write off activity in 2020 was not reflective of a normal year's level. This was due to the disconnection moratorium that was implemented beginning in March 2020 pursuant to the Governor's Executive Order 2020-04 and Emergency Order #3, and Commission Order No. 26,343.

Q. How is the Company proposing to address the write off activity that will occur now that the disconnection moratorium has been lifted?

A. To ensure that the Company is recovering a representative level of bad debt expense in distribution rates, the Company proposes to track the actual delivery write offs against the level in distribution rates and to recover the difference annually through the Company's proposed Regulatory Cost Adjustment Mechanism ("RCAM") as part of the Local Delivery Adjustment Charge ("LDAC"). The Company does not expect actual write-offs to return to pre-pandemic levels for some time.

Q. Has the Commission issued an order in Docket IR No. 20-089 regarding the recovery of incremental bad debt expense?

A. Yes. In Order No. 26,495 (July 7, 2021) the Commission declined to authorize New Hampshire's public distribution utilities to establish a regulatory asset for incremental bad debt expense or waived late payment fees related to the Covid-19 pandemic. However, the Order states: "recovery of these expenses is best addressed in the context of each utility's next rate case when such costs (to the extent they remain relevant under test year based rate-setting) can be appropriately considered in the context of each company's full revenue requirement and overall rate of return." Order at 9 (July 7, 2021).

Q. How is the Company proposing to recover the incremental bad debt expense that the Company has incurred beginning March 31, 2020?

A. Consistent with the bad debt tracker proposal described above, the Company is proposing to track the actual bad debt expense to the amount currently in distribution rates and to recover or flow back the incremental difference through the Company's proposed RCAM as a component of the LDAC.

Q. Why is it necessary for the Company to handle the bad debt in this manner?

A. Due to the pandemic and the disconnection moratorium, and the timing of the moratorium terminating, it is anticipated that it will be a multi-year process before Unitil experiences a normal level of write off activity. On June 30, 2020 Emergency Order #3 terminated and Emergency Order #58 was enacted that further provided that the New Hampshire utilities "shall offer payment arrangements, refrain from charging late fees, and begin normal collection activity and disconnections consistent with an agreement between a utility or utilities and the Commission's Consumer Services and External Affairs Division, subsequent order of the Commission, and/or rules adopted by the Commission pursuant to RSA 541-A". In complying with Emergency Order #58, on September 10, 2020, the Utilities along with the New Hampshire Public Utilities Staff, Office of the

Consumer Advocate, New Hampshire Legal Assistance and LISTEN filed a settlement[1] extending the shut off and disconnection moratorium until April 1, 2021 and subsequent amendment to the settlement extending the date to May 31, 2021. The shut off and disconnection moratorium has led to an abnormal increase in past due account receivables which have the potential to lead to higher than historic bad debt expense levels.

4. NON-DISTRIBUTION BAD DEBT

Q. Please explain the adjustment for Non-Distribution Bad Debt.

A. As discussed earlier in our testimony, we removed revenue associated with non-distribution bad debt. In O&M Expense, we also remove these same amounts on Schedule RevReq-3-2.

5. MEDICAL & DENTAL INSURANCE

Q. What is the purpose of the Medical & Dental Insurance Adjustment?

A. The test year O&M expense has been pro formed to increase test year medical and dental insurance by $404,594. This adjustment is shown on Schedule RevReq-3-6, and includes amounts allocable to the Company from Unitil Service. The adjustment is based on actual working rates for 2021, and an estimated increase for 2022. Before the completion of this proceeding, this adjustment will be updated to reflect actual 2022 working rates. This adjustment is supported and

[1] Settlement was approved in Docket No. IR 20-089 by Secretarial Letter issued on October 5, 2020.

presented in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

6. RETIREMENT COSTS

Q. Please explain the pension, postemployment benefits other than pension, supplemental executive retirement plan, 401(k) adjustments and deferred compensation expense.

A. The purpose of the pension, postemployment benefits other than pension ("PBOP"), supplemental executive retirement plan ("SERP"), 401(k), and deferred compensation expense adjustments is to update these costs from test period O&M expense. The latest year-end 2020 actuarial report, which provides 2021 calendar year expense, was the basis for the pension, PBOP, and SERP adjustment. The 2020 401(k) and deferred compensation expense was adjusted to reflect the effect of the payroll increases referenced above. The pension, PBOP, SERP, 401 (k), and deferred compensation expense adjustments are all provided in Schedule RevReq-3-7 which shows a pension decrease of $2,185, a decrease to PBOP expense of $19,749 and increases to SERP, 401(k) and deferred compensation expense of $58,798, $30,095 and $44,415, respectively. These adjustments include costs for the Company as well as costs allocable to the Company from Unitil Service. This adjustment is supported and presented in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

7. PROPERTY & LIABILITY INSURANCE

Q. Please describe Northern's property and liability insurance coverage and the adjustment to test year property and liability insurance expense.

A. Property and liability insurance coverage includes a number of types of insurance that provide protection from casualty and loss, and other damages that the Company may incur in the conduct of its business. Northern's insurance program includes both premium-based and self-insured coverages, in order to obtain the widest portfolio of insurance coverage at the most reasonable cost. As shown on Schedule RevReq-3-8, the pro forma adjustment for property and liability insurances is an increase of $60,699 to test year O&M expense. This adjustment was made to adjust the property and liability insurance test year O&M expense to reflect known and measurable changes in premiums for the Company and for premiums allocable to the Company from Unitil Service. The premiums shown on Schedule RevReq Workpaper 4.3 include actual costs for 2021 insurance policies. The Company will provide actual costs for 2022 insurance policies when they become available during the course of this proceeding.

Q. Please describe how the Company takes reasonable measures to control property and liability insurance.

A. The Company evaluates its property and liability annually with the aid of its insurance broker to ensure the Company is able to secure the best available coverage at the best available rates. To balance the risk mitigation that insurance provides and the level of premium costs, an appropriate level of self-insurance deductible is negotiated with insurance carriers. Higher deductible levels result in lower insurance premiums while also resulting in a higher retention of risk of loss. The Company must manage the balance between risk exposure and deductible cost.

The Company employs a well-accepted process when procuring insurance programs. To get the optimal coverage at the best cost, the Company uses its broker to facilitate the process. The broker compiles market submissions and works with various insurance markets to solicit quotes for the Company. The broker monitors the insurance markets and provides information helpful to coordinate a reasonable renewal. The Company's broker also benchmarks peer companies to see how our limits and retentions compare in the industry. If adjustments are needed, the benchmarking analysis provides support to senior management to support any changes. On a combined basis, these processes assist in assuring that the Company's property and liability insurance are as reasonable as possible.

8. REGULATORY ASSESSMENT FEES

Q. Please explain the adjustment related to regulatory assessment fees.

A. Currently, the Company collects regulatory assessment fees in base rates and through its Gas Assistance Program and Regulatory Assessment ("GAPRA") mechanism. The proposed adjustment shown in Schedule RevReq-3-9 moves all recovery into base rates, with any incremental changes to be recovered or refunded through the RCAM. The adjustment increases expenses by $116,230 and is necessary to comply with the requirements in RSA 363-A:6,II. The adjustment does not reflect any additional impact to ratepayers or additional revenue to the Company. Rather, it merely moves recovery of the assessment from the GAPRA mechanism to base rates.

9. DUES & SUBSCRIPTIONS

Q. Please explain the adjustment related to dues and subscriptions.

A. The Company has reduced test year operating expense by $1,774 in Schedule RevReq-3-10 to remove the lobbying portion of the Company's annual membership dues to the American Gas Association to comply with the requirements in RSA 378:30-e.

10. PANDEMIC COSTS

Q. Please explain the adjustment related to pandemic costs.

A. As shown in Schedule RevReq-3-11, this adjustment removes $107,125 of pandemic related costs that were charged during the 2020 test year. The Company believes that these costs were anomalous and should not be included on a forward looking basis for ratemaking purposes.

11. SEVERANCE EXPENSE

Q. Please explain the adjustment related to severance expense.

A. As reflected in Schedule RevReq-3-12, we have reduced test year severance expense by $29,947. The Company believes that severance expense is a periodically recurring expense but that the test year expense may not be a representative level. Therefore, the Company normalized test year expense to reflect a representative test year level to be recovered in rates, calculated as the average of the most recent five-year expense amounts.

12. RENT EXPENSE

Q. Please explain the adjustment related to rent expense.

A. The Company has increased test year rent expense by $51,913 for estimated rent expense due to Unitil Service for use of the new Exeter Distribution Operating Center. The Company intends to update this amount for actual 2021 rent expense during the pendency of this case, but does not expect the amount to materially change from its estimate.

13. ARRERAGE MANAGEMENT PROGRAM IMPLEMENTATION

Q. Please explain the adjustment for Arrearage Management Program (“AMP”) implementation.

A. The Company is proposing an AMP as part of the filing as provided in the prefiled testimony of Ms. Carole Beaulieu. The $92,480 amount shown on Schedule RevReq-3-14 is related to the estimated cost of a full time employee to be hired to run the program split between the Company and Unitil Corp.’s New Hampshire electric distribution operating company, Unitil Energy Systems, as well as the annual program forgiveness costs.

Q. What happens if the program cost are greater or less than the $92,480 include for recovery in base distribution rates?

A. The Company is proposing to track the actual cost of the program and reconcile the cost annually against the $92,480 that is included in base distribution rates. Any variance from the level in rates will be deferred and refunded or recovered as part of the following years RCAM.

14. INFLATION ALLOWANCE

Q. Is the Company proposing an Inflation Allowance?

A. Yes, it is. We have calculated an inflation allowance to recognize the impact of inflation over time on the Company's expenses. The inflation adjustment recognizes that known inflationary pressures, not subject to the control of Northern, tend to affect the Company's operating expenses in a manner that can be reasonably measured. The adjustment is limited to an allowance for those expenses that cannot be adjusted separately ("residual O&M Expense") and extends to the date that permanent rates go into effect.

Q. Please describe the adjustment for Inflation.

A. An inflation allowance has been applied to test year residual O&M Expenses, as shown on Schedule RevReq-3-15 Page 1. In order to determine the level of test year residual O&M Expenses, we reduced test year O&M Expenses by: (1) expenses that have been adjusted separately; and (2) expenses that are not subject to general inflation. The inflation adjustment on residual O&M is based on a cumulative inflation rate of 5.12 percent over a 25-month period, which represents the increase in the Gross Domestic Product Implicit Price Deflator ("GDPIPD") from the mid-point of the test year (July 1, 2020) to August 1, 2022 (date of permanent rates), as shown on Schedule RevReq-3-15 Page 2. We have also provided the published GDPIPD factors on a monthly basis from 2019 to the currently available end of year 2022 in Workpaper 6.1.

Q. What inflation allowance was calculated?

A. The calculation produces an inflation allowance of $165,684 as shown on Schedule RevReq-3-15 page 1, line 19.

III. DEPRECIATION EXPENSE

Q. Is Northern proposing an annualization adjustment for depreciation for the test year?

A. Yes. We have applied the currently authorized depreciation rates to test year-end depreciable plant balances to derive the annualized Depreciation Expense. The annualization of depreciation expense based on the twelve months ended December 31, 2020 depreciable plant balance is detailed in Schedule RevReq-3-16 page 1. The annualization adjustment increases the depreciation expense by $469,003.

Q. What depreciation rates did you use for the annualization adjustment?

A. The Company used the depreciation rates that were approved in the Company's last settlement agreement in Docket No. DG 17-070.

Q. Is the Company proposing an adjustment to depreciation expense for any proposed changes in depreciation rates?

A. Yes. The depreciation adjustment, detailed on Schedule RevReq-3-16 page 2, increases the test year depreciation expense by $1,847,988. The new depreciation rates and reserve adjustment for amortization are presented in the prefiled testimony of Mr. Ned Allis.

IV. AMORTIZATION EXPENSE

Q. Have you made any adjustments to amortization expense for information technology or software projects?

A. Yes. We have made an adjustment to provide for an adequate level in the cost of service for information technology and software amortization expense based upon known and measurable changes through the end of 2021.

Q. Please describe the methodology you used for this adjustment.

A. As provided in Schedule RevReq-3-17, the Company projected rate year amortization based on projects currently in service and expected information technology projects to be put in service through the end of 2021. Then, the adjustment removes the amortization expense of any project expected to be fully amortized during 2021. The Company then compares the projected rate year amortization versus the test year for an increase of $189,288. The Company will update this adjustment during the course of the proceeding for actual information technology projects to be put in service through the end of 2021.

V. EXCESS ACCUMULATED DEFERRED INCOME TAXES ("ADIT")

Q. Please explain the Excess ADIT adjustment.

A. As described further in the Testimony of Mr. Jonathan A. Giegerich, the Company is proposing to begin flowing back Excess ADIT to ratepayers. The Excess ADIT flowback included in the revenue requirement calculation is $308,218, as shown in ScheduleRevReq-3-18. The detailed calculation of the Excess ADIT flowback has been included as Exhibit JAG-6, Page 1 of 1, column d, line 4.

VI. TAXES OTHER THAN INCOME

1. PROPERTY TAXES

Q. Has the Company adjusted the test year property tax expense?

A. Yes. The adjustment is detailed on Schedule RevReq-3-19 and amounts to an estimated increase in property tax expense of $617,939. This schedule presents information related to property taxes including taxation period, local tax rate, assessed valuations, and taxes paid based on final 2020 tax bills by municipality.

Q. Will this adjustment be updated?

A. Yes. This adjustment will be updated during the pendency of this proceeding to reflect the final 2021 tax bills. Typically, the second billing installments are received in October and November, with payments due in November and December.

Q. Were there property tax abatements received during the test year?

A. Yes, the test year reflects on line 31 of Schedule RevReq-3-19 an amount of $688 related to property tax abatements received in 2020 for prior years, which do not impact the Company's current year's taxes and thus need to be removed.

Q. How is the Company planning to address the future changes in property taxes that will occur related to HB 700?

A. As described in greater detail below is Section IV, the Company is proposing to track and recover the increase in local property taxes as part of the RCAM.

2. PAYROLL TAXES

Q. Have test year payroll taxes been adjusted to account for pro forma payroll increases?

A. Yes, as shown on Schedule RevReq-3-20 P1, an adjustment of $42,415 was prepared to pro form the amount of Northern and Unitil Service's portion of the Social Security and Medicare taxes related to the adjustment to the payroll adjustment described above. The adjustment is supported and presented in the prefiled testimony of Mr. John Closson and Mr. Joseph Conneely.

Q. Have test year payroll taxes been adjusted for employee retention and other pandemic payroll tax relief credits?

A. Yes, as shown on Schedule RevReq-3-20 P2, an adjustment of $95,258 was prepared to remove the reduction to test year payroll taxes as a result of the Company's use of employee retention and other pandemic payroll tax relief credits. The adjustment is supported and presented in the prefiled testimony of Mr. Jonathan Giegerich.

VII. INCOME TAXES

Q. Does the cost of service reflect adjustments to test year income taxes to reflect pro forma changes?

A. Yes. The adjustment is summarized on Schedule RevReq-3-21, pages 1-2. The adjustment to test year income taxes calculates the income tax effect of the adjustments to revenues and expenses previously described in our testimony and as listed in the Summary of Adjustments in Schedule RevReq-3. The adjustment also reflects the income tax effect of the adjustment for interest expense synchronization with rate base, based on the difference between interest expense for ratemaking and test year interest expense, which is shown on Schedule RevReq-3-21, page 2.

Q. Please explain the adjustments for prior year federal and state income taxes as shown in Schedule RevReq-3-21, page 4.

A. As part of its normal tax accounting practice, the Company accounts for prior years return to accrual in its current year tax provision. The adjustment in Schedule RevReq-3-21 page 4 removes the prior year return to accrual and other prior year tax adjustments so that the adjusted cost of service reflects current year income taxes only.

VIII. RATE BASE

Q. Have you provided the balance sheets for Northern?

A. Yes, we have provided Assets & Deferred Charges and Stockholder's Equity and Liabilities in Schedules RevReq-4-1 and 4-2, respectively. We have also provided detailed plant and accumulated depreciation information in Schedules RevReq-4-3 and 4-4, respectively.

Q. Please summarize the information you have provided to support the rate base used to determine Northern's revenue requirements.

A. Schedule RevReq-5 summarizes the rate base. The summary includes several calculation methodologies, including the "Test Year Average" (arithmetic average of the beginning and end of test period amounts) of $182.9 million, the "5 Quarter Average" of $179.0 million, the "Rate Base at December 31, 2020" of $188.0 million, and the "Pro Forma Rate Base at December 31, 2020" of $188.7 million. The pro forma rate base at December 31, 2020, was used to determine Northern's revenue requirement.

Q. What did you consider in selecting a year-end rate base?

A. Utility Plant in Service consistently increases quarter-over-quarter. Thus, a year-end rate base is appropriate for Northern given the significant annual growth in the primary component of its rate base, Utility Plant. As described in greater detail in the prefiled testimony of Mr. Robert Hevert, Northern is a capital intensive Company, and without the timely recovery on those investments revenue will not be sufficient to cover incremental costs, which leads to earnings attrition. A year-end rate base reduces earnings attrition, because it aligns expenses, revenues and rate base with the period in which rates are going to be in effect. Finally, the year-end rate base was utilized in the Company's last three base distribution rate cases in Docket DG 11-069, Docket DG 13-086 and Docket DG 17-070, and we believe it is appropriate to continue this practice.

Q. Since the Company's last base rate proceeding, has Northern added utility plant to its operations?

A. Yes. Pro Forma Distribution Utility Plant in Service has grown from $212,059,659 in pro forma 2016 (the Company's most recent rate case test year) to $301,245,498 in pro forma 2020 (a 42.1 percent increase). Adjusting these amounts by the 2016 and 2020 Reserves for Depreciation and Amortization, Net Utility Plant has grown from $145,142,807 in pro forma 2016 to $211,872,045 in pro forma 2020 (a 46.0 percent increase). Refer to Docket No. 17-070 Settlement Agreement, Exhibit 1, Page 45 of 95 for pro forma 2016 information and Schedule RevReq-5, column 7 for pro forma 2020 information.]

Q. Please describe the component of rate base information on Schedule RevReq-5-1.

A. Schedule RevReq-5-1 presents the balance of rate base items for each of the 5 quarters beginning with the balance at December 31, 2019 and ending with the balance at December 31, 2020. In the last column, the 5-Quarter Average is calculated.

Q. Please describe the cash working capital component of rate base information on Schedule RevReq-5-2.

A. The calculation of cash working capital in rate base is detailed in this schedule. The calculation consists of a 36.49 day lead-lag factor applied to test year distribution operating expenses. This lead-lag factor is based on the Company's lead-lag study as presented in the prefiled testimony of Mr. Daniel Hurstak. Northern proposes to include $2,008,385 of cash working capital in Base Distribution rate base.

Q. What is cash working capital?

A. As described in greater detail in the prefiled testimony of Mr. Daniel Hurstak, cash working capital is the amount of capital expended and required by Northern to fund its day-to-day operations. In other words, cash working capital represents funds expended by the Company to provide service prior to the payment for such service by Northern's customers. Pursuant to Commission precedent, cash working capital is an addition to Northern's rate base.

Q. Please list the other components added to rate base.

A. In addition to Net Utility Plant in Service and Cash Working Capital described above, Materials and Supplies Inventories and Prepayments have all been added to rate base. These items are shown on Schedule RevReq-5 and RevReq 5-1.

Q. Please list the components deducted from rate base.

A. These items consist of Net Deferred Income Taxes, Excess Deferred Income Taxes, Customer Deposits, and Customer Advances and are also shown on Schedule RevReq-5 and 5-1.

Q. Has the Company revalued all ADIT as of December 31, 2017 to reflect a 21 percent federal tax rate as a part of Tax Cuts and Jobs Act of 2017 ("TCJA")?

A. Yes. As discussed further in the prefiled testimony of Mr. Jonathan Giegerich, the most significant corporate effect of the TCJA is reducing the top federal corporate tax rate from 35 percent to 21 percent, which caused the Company to revalue all ADIT balances as of December 31, 2017. The corresponding entry to reduce net ADIT Liabilities was recorded as a Regulatory Liability according to Federal Energy Regulatory Commission ("FERC") guidance, Docket No. AI93-5-000. According to FERC guidance, once a utility's ADIT are no longer owed to the government under the new rates, and the ADIT balance represents amounts previously collected from customers in utility rates, the Liability for excess ADIT no longer exists and, instead, a Regulatory Liability for the amounts to be returned to customers exists and will be properly classified that way in the FERC chart of accounts, Docket No. AI93-5-000.

Q. Please describe how the Company calculated excess ADIT as of December 31, 2017.

A. The Company scheduled out into future periods the timing of the turning of its ADIT balances and reconciled all of its ADIT underlying book/tax temporary differences as of December 31, 2017. Once the underlying book/tax temporary differences were reconciled, the Company adjusted, or "revalued," the federal ADIT accounts at the new federal corporate tax rate. A net Regulatory Liability in the amount of $6,572,092 was recognized to be returned to customers in future rates and is shown in Schedule RevReq-5 and Schedule RevReq-5-1.

Q. Please explain Schedule RevReq-5-3 which contains the Supplemental Plant Pro Forma Adjustment.

A. This schedule contains plant in service and accumulated depreciation for the Company's production facilities, including a LNG plant located in Maine. This schedule allocates these production plant and depreciation balances to either New Hampshire or Maine based on the Company's Fixed Demand factor (40.88% NH and 59.12% ME). The Company allocates the production facilities based on this methodology because the Company manages a combined system where the costs are allocated among the states based on relative gas usage. This methodology was approved in the Stipulation and Settlement approved by the Maine Commission in Docket No. 2005-00273 and by the New Hampshire Commission in Docket DG 05-080.

Q. Please explain Schedule RevReq-5-4 which contains a deferred income tax adjustment.

A. In Docket DG 08-048 and DG 08-079, the Company agreed to hold ratepayers harmless from the tax impact of Unitil Corp's acquisition of the Company. In this acquisition, a 338(h)(10) election was made which eliminated the Company's historical accumulated deferred income taxes. In the Stipulation approved by the Commission in Docket DG 08-048 and DG 08-079, the Company agreed to maintain pro forma accounting for regulatory purposes of the historical deferred income tax balance assuming the acquisition had not occurred. This historical deferred income tax balance is then used for ratemaking purposes until such time that the newly acquired deferred income tax balance equals or exceeds the historical balance. This schedule provides both the historical and newly acquired deferred income tax balances and utilizes the historical balance for ratemaking purposes. The Schedule shows that the acquired deferred income tax balance exceeds the historical balance as calculated on Schedule RevReq-5-4, Line 3. The Schedule then incorporates deferred income tax balances as a result of capital spending post-acquisition and deferred taxes due to net operating losses. The deferred taxes associated with net operating losses have been adjusted to reflect losses attributable to rate base. Since the Company's post acquisition deferred income tax balance exceeds the historical balance an adjustment is no longer necessary as shown on Schedule RevReq-5-4, Line 8.

IX. RATE OF RETURN

Q. What rate of return have you used for ratemaking purposes?

A. As shown on Schedule RevReq-6, Northerns's weighted cost of capital is calculated to be 7.75 percent. As described in the prefiled testimony of Messrs. Todd Diggins and Andre Francoeur, this is derived from the Company's capital structure and related costs for various capital components and represents the required rate of return on rate base used in the determination of the Company's revenue requirement.

Q. Please summarize the total rate of return.

A. The Company's weighted cost of capital is 7.75 percent, as shown on Schedule RevReq-6. We have applied this weighted cost of capital to the rate base of $188,719,257, shown on Schedule RevReq-1, to calculate the return on the rate base. The result is a total required return on rate base of $14,621,110 as shown on Schedule RevReq-1, line 3.

Q. Is there anything else you would like to add regarding the rate of return?

A. Yes. As described in the testimony of Mr. Robert Hevert and Messrs. Diggins and Francoeur, the Company has requested a Return on Equity of 10.30 percent, which is toward the lower end of the Return on Equity range recommended by our expert Mr. John Cochrane. The Company's decision to request a Return on Equity of 10.30 percent is described in greater detail in the prefiled testimony of Mr. Hevert.

IV. 2021 RATE PLAN

Q. Are you proposing a rate plan in this filing?

A. Yes, the Company is proposing a multi-year rate plan with annual step adjustments to recover the revenue requirement of non-growth capital additions to rate base. The 2021 Rate Plan is outlined in detail in Schedule CGDN-1.

Q. What additions to plant will be eligible for recovery?

A. As more fully described in the prefiled testimony of Messrs. Sprague and Leblanc, eligible Non-Growth Plant Additions are defined as capital spending related to pipe replacement programs, other replacement programs, system improvements, highway projects, asphalt restoration, farm tap replacement, the Rochester Reinforcement project, and other non-growth related projects.

Q. For what years will the 2021 Rate Plan apply and what is the timing for filings with the Commission and rate implementation?

A. The plan will encompass three annual step adjustments to recover the revenue requirement. The step adjustments would take place in August of 2022, 2023 and 2024 for investment years 2021, 2022, and 2023. Each step adjustment compliance filing would be made with the Commission on or before the last day of March for the prior year's additions. Then, the resulting rate changes would go into effect August 1. For example, the filing for investment year 2021 additions would be filed with the Commission by March 31, 2022 with rates going into effect August 1, 2022, coinciding with the permanent rates from this proceeding.

Q. Have you prepared a schedule to demonstrate the calculation of the Company's proposed 2021 Rate Plan?

A. Yes, we have prepared Schedule CGDN-2 Pages 1-3 for that purpose. The schedule is based on the Company's capital budget presented by Messrs. Sprague and Leblanc. The schedule is for illustrative purposes, since actual plant additions will vary from the long-term forecast of the annual capital spending budget.

Nevertheless, the schedule illustrates the express mechanics of the revenue requirement calculation.

Q. Please describe the derivation of Rate Base on page 1 of Schedule CGDN-2.

A. Rate Base is calculated by sourcing lines 1 and 2 from the Company's plant accounting records to arrive at the 2021 Rate Plan Non-Growth Capital Expenditures as shown on line 3. Accumulated Depreciation is calculated on line 4 by taking 50% of the calculated Depreciation Expense. Next, Accumulated Depreciation is removed from the 2021 Rate Plan Non-Growth Capital Expenditures to derive Net Utility Plant as shown on line 5. Then Accumulated Deferred Income Taxes (ADIT) is calculated on line 6 by applying the Effective Income Tax Rate to the difference between Book and Tax Depreciation as shown on lines 18-26. Lastly, ADIT is deducted from Net Utility Plant to get the Rate Base associated with 2021 Rate Plan Non-Growth Capital Expenditures as shown on line 7. While Schedule CGDN-2 formulaically derives Rate Base based on the capital budget provided in this proceeding, the intent of the Company is to source Non-Growth Capital Expenditures from its plant accounting records on an annual basis.

Q. Please describe the derivation of Revenue Requirement on page 1 of Schedule CGDN-2.

A. As described above, once Rate Base is calculated it is multiplied by the Pre-Tax Rate of Return on line 9 to derive the Return and Related Income Taxes on line 10. Next, Depreciation Expense associated with eligible Non-Growth Plant

Additions is calculated on lines 18-20 based on a composite depreciation rate of 3.73 percent, which is calculated in Line 39 Column 3 from Schedule RevReq-3-16, Page 2. Then, State Property Taxes are calculated on Net Utility Plant on line 12 using a property tax rate of 0.66%, which corresponds to the statutory tax rate in RSA 83-F:2, currently $6.60 per $1,000 of investment. The Company would update this rate annually based on the latest property tax rates. Finally, Return and Related Income Taxes, Depreciation and Property Taxes are added together to arrive at the Revenue Requirement on line 13.

Q. What schedules support Schedule CGDN-2, Page 1?

A. Schedule CGDN-2, Page 2 presents the capital budget by year for Non-Growth Capital Expenditures for illustrative purposes. Again, actual plant accounting records will be used in calculating 2021 Rate Plan Non-Growth Capital Expenditures. Schedule CGDN-2, Page 3 shows the calculation of the pre-tax rate of return.

Q. Please describe the impact of New Hampshire House Bill ("HB") 700 on the Company.

A. HB 700 established a methodology for valuing utility distribution assets for property tax purposes, codified as RSA 72:8-d and –e. The law established a new methodology for assessing utility property taxes, and a five-year phase-in period to fully transition to that new methodology. The first property tax year of the phase-in period is the tax year beginning April 1, 2020. The law also requires the

Commission to establish by order a rate recovery mechanism for the property taxes paid by a public utility.

Q. Did HB 700 allow for increases in all property taxes to be recovered?

A. No, HB 700 allowed for the recovery of increases in property taxes associated with "Utility company Assets" defined as:

> "Utility company assets" means the following property not exempt under RSA 72:23:
>
> (2) For a gas company providing gas service to retail customers: distribution pipes, fittings, meters, pressure reducing stations, buildings, contributions in aid of construction (CIAC), construction works in progress (CWIP), and land rights including use of the public rights of way, easements on private land owned by third parties, and land owned in fee by the gas company.

Q. How does the Company intend to incorporate the impact of New Hampshire House Bill ("HB") 700?

A. The Company recently made a filing in Docket No. DG 21-123 on June 21, 2021. Consistent with RSA 72:8-d and -e, property tax over- or under-recoveries as compared to the amount in base distribution rates shall be adjusted annually through the Company's RCAM on November 1 of each year. The amount included in base distribution rates for property tax expense shall be $5,346,199[2]

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[2] Amount will be updated during the pendency of this proceeding to reflect the final 2021 tax bills.

based on property tax expense as of December 2021, as described above, normalized to exclude any credits related to property tax settlement proceeds for tax years preceding the test year. This amount would be updated annually as a part of the Company's RCAM filing for the inclusion of property tax expenses to be recovered through the Company's 2021 Rate Plan. On an annual basis, actual property tax expense for the prior calendar year shall be compared against the amount in base rates and any variances will be reconciled through the RCAM mechanism. Annual actual property tax expense shall be normalized to adjust for any credits received due to abatement settlement proceeds received for tax years preceding the test year. As proposed in Docket No. DG 21-123, the RCAM shall recover any over- or under- recoveries beginning on November 1 of each year.

Q. Is the Company's property tax recovery proposal in Docket No. DG-123 limited to the recovery of increases associated with local – utility plant assets only?

A. No. For administrative efficiencies and simplified reconciliation, the Company has proposed that the annual recovery includes the reconciliation of all local property taxes (local building and utility plant assets).

Q. How does the Company propose to address the change in state related property taxes?

A. The Company is proposing to exclude the changes in the state related property taxes from the recovery proposal consistent with the language of HB 700. Recovery of the state portion of the property taxes would be recovered on Non-

Growth Utility Plant, as described above during the term of the 2021 Rate Plan and thereafter would continue to occur as it does now as part of the normal rate case process.

Q. Can you summarize the revenue requirement results for the proposed 2021 Rate Plan?

A. The revenue requirement that will be derived from the step adjustments ranges from $3.1 million (in investment year 2021 and 2022) to $3.2 million (in investment year 2023) depending on the level of plant investments in a given forecast year. The step adjustments represent 4.7 percent to 4.8 percent of test year operating revenue. Again, these revenue requirement results are forecasts based on the Company's capital budget. Actual Non-Growth Plant Additions will vary from this forecast.

Q. Are there consumer protections included in the 2021 Rate Plan?

A. Yes, as described earlier, the Company would submit an annual compliance filing subject to Commission review and approval. As outlined in Schedule CGDN-1, the Company proposes a revenue requirement cap of $10,500,000 which is the sum of the revenue requirements for investment years 2021-2023 plus an increase of approximately 10%. The additional approximate 10% is to accommodate unknown conditions, such as municipal projects that may arise in the future but are not known today. The Company would also commit to a base rate case stay-out through 2024, subject to certain exogenous factors and considerations. The Company proposes an ROE collar which would allow the Company to file a base rate case before 2024 if ROE was under 7 percent, but provides for earnings sharing of 50 percent if ROE is greater than 11 percent. In addition, the 2021 Rate Plan includes features for exogenous events and excessive inflation.

V. TEMPORARY RATES

Q. Is the Company requesting that temporary rates be set in this proceeding?

A. Yes. The Company requests that temporary rates be established in the amount of $3,220,742 on an annualized basis to become effective on October 1, 2021. The development of the temporary rate amount is detailed in Schedule CGDN-3.

Q. Please explain how the temporary rate amount of $3,220,742 was derived?

A. In general, the Company employed a conservative approach in calculating the amount of the temporary rate request. The amount of the temporary rate request was based on 2020 test year-end rate base. The cost of capital used in the calculation is based on the rate case filing capital structure and debt costs as provided in Schedule RevReq-6. However, the cost of equity was set lower at 9.50 percent reflecting the last authorized return on equity awarded to the Company in its last base rate case. As shown in Schedule RevReq-1 of Schedule-CGDN-3, this results in an overall cost of capital of 7.33 percent. The test year net operating income was adjusted to reflect a handful of pro forma adjustments, as shown in Schedule RevReq-3 of Schedule CGDN-3, and also portrays a weather-normal 2020 distribution test year. In general, the pro forma adjustments selected were confined to the 2020 test year, such as depreciation annualization to bring depreciation levels up to year-end balances, and property taxes to reflect the most recent annualized 2020 property tax bills. No adjustments pertaining to 2021 and beyond were incorporated.

Q. Please describe the derivation of the proposed temporary delivery charge per therm.

A. The calculation of the annualized proposed temporary rate increase of $0.0876 per therm for rates R5, R6 and R10 and $0.0279 per therm for rates G40, G50, G41, G51, G42, G52 is provided in Schedule CGDN-4. The temporary rates were calculated for residential and commercial and industrial customers by first proportionally allocating the proposed temporary revenue requirement by adjusted 2020 test year revenue. Next, the proposed temporary delivery charge per therm was determined by dividing the residential or commercial and industrial proportioned increase by the test year adjusted weather-normalized delivery volumes rounded to four decimals. The temporary rate surcharge will not be applied to special contract customers.

Q. How does the Company account for and collect the difference between temporary rates and permanent rates once the Commission issues its order for permanent rates?

A. After the Commission issues its order in this case, the Company will submit a filing to collect the difference in revenue (or "recoupment") between temporary and permanent rates from the date temporary rates went into effect to the date permanent rates became effective. The recoupment surcharge will be a charge per therm, applied to all rate schedules, and included in the LDAC.

VI. OTHER REGULATORY PROPOSALS AND CONSIDERATIONS

Q. What other proposals and considerations is the Company making?

A. The Company is proposing and presenting information regarding the following areas:

1. Waived Late Payment Charge Revenues for the period April 2020 through March 2021
2. Special Contract Revenues
3. Mains Extension Project Updates
4. Epping Franchise Expansion

We will discuss each adjustment individually in the following section.

1. WAIVED LATE PAYMENT CHARGES

Q. Has the Company been impacted by the New Hampshire emergency order prohibiting utility disconnections and application of utility late payment fees?

A. Yes, as a result of the shut off and late fee prohibition, Northern was not able to apply late fees to customer's accounts beginning in March of 2020. For the calendar year 2020, the Company charged $36,803 in late payment fees to customers, which is well below the amount that was included when distribution rates were last set in Docket No. DG 17-070 and what the actual amount of late payment fees the Company would have charged to customers if the late payment fee prohibition was not in place.

Q. In Docket No. DG 17-070, what level of late payment charge revenues was included in the Company's distribution rates?

A. The level of late payment charge revenue included in the revenue requirement approved via settlement in that docket was $104,863. This amount was equal to the actual late payment charge revenues for 2016.

Q. How much late payment fees did the Company waive in 2020?

A. Northern waived $133,719 of late payment fees for the 9 month period of April through December 2020 and is $183,462 of late payment fees for the 12 months ended March 31, 2021. Table 2 below provides a summary of the actual waived late fees waived by month for both time periods.

Table 2: Late Payment Fee Summary

Late Payment Charge ("LPC") Revenues
Northern Utilities, Inc.

LPC Revenues	Docket No. DE 17-070 2016 (TY)	2020	Moratorium Period 2020	Moratorium Period 2020/2021	Comment
January	$ 7,985	$ 14,196			Charged - Actual
February	9,423	15,930			Charged - Actual
March*	16,764	6,677			Charged - Actual
April	13,105		$ 16,052	$ 16,052	Waived - Actual
May	14,749		21,297	21,297	Waived - Actual
June	11,837		20,319	20,319	Waived - Actual
July	7,393		15,693	15,693	Waived - Actual
August	7,909		14,976	14,976	Waived - Actual
September	3,037		12,047	12,047	Waived - Actual
October	4,033		12,473	12,473	Waived - Actual
November	4,036		10,239	10,239	Waived - Actual
December	4,592		10,623	10,623	Waived - Actual
January				13,688	Waived - Actual
February				16,386	Waived - Actual
March				19,669	Waived - Actual
Total LPC Revenues	$ 104,863	$ 36,803	$ 133,719	$ 183,462	

*Moratorium began in March 2020 and ended March 2021

Q. Is the $183,462 of waived late payment fees material to Northern?

A. Yes, the amount is material to Northern. For 2020, this amount represents roughly 2 percent of the Distribution Operating Income and 0.43 percent of the 2020 Test Year weather normalized distribution revenues.

Q. What is the Company proposing related to recovery of the $183,462 of waived late payment fees for the 12 month period ended March 31, 2021?

A. For the 12 months ended March 31, 2021, the Company is proposing to recover $104,863, which is the amount included in rates in Docket No. DG 17-070. This amount is lower than the actual waived late payment fees amount of $183,462. The Company would propose that the $104,863 be recovered as part of the Company's proposed RCAM.

2. SPECIAL CONTRACT REVENUES

Q. Is the Company proposing to include special contract revenue in decoupling?

A. No. As detailed in the testimony of Mr. Tim Lyons, the special contract revenue is being proposed to be exlcuded from the decoupling mechanism.

Q. Is the Company proposing any special treatment associated with the special contracts?

A. Yes. The Company is proposing that any change in special contract revenue from the test year adjusted amount of $1,197,813 that is included in the revenue requirement be reconcilled annually and any over or under recovery would be included in the RCAM.

3. MAINS EXTENSION ANALYSIS

Q. Please explain the Commission's decision to temporarily disallow investment related to two projects in the Company's most recent step increase in Docket No DG 17-070.

A. In the Company's last rate case, DG 17-070, the Commission approved a settlement agreement allowing a permanent increase in distribution rates (effective May 1, 2018) as well as an initial step increase (also effective May , 2018) and the option for a second step increase (effective May 1, 2019). DG 17-170, Northern Utilities, Inc., Order No. 26,129 at 14-15 (May 2, 2018). Northern filed a request for a step increase on February 28, 2019. During the course of the proceeding Staff recommended two disallowances to the step adjustment (and permanent rate base) related to projects involving customer CIACs ("Contributions in Aid of Construction"). Staff argued that the Company did not collect sufficient CIACs on two specific projects, 201 Atlantic Avenue, North Hampton and 10 Hampshire Road, Salem. The Commission adopted the Staff's recommended disallowance for the purposes of the step adjustment, but allowed the Company to make a presentation in its next rate case demonstrating why the full cost of the main extensions should be included in rate base. DG 17-070, Northern Utilities, Inc., Order No. 26,246 at 7 (May 2, 2019).

Q. Is this Company seeking to include the full cost of main extension projects at 201 Atlantic Avenue in North Hampton and 10 Hampshire Road in Salem?

A. Yes.

Q. How does the Company determine the CIAC amount to charge to a customer prior to undertaking a main extension project?

A. Any extension of gas main is treated on the basis that the project will have to meet the Company's rate of return criterion. A project may consist of a single building or a group of buildings, so long as the buildings are in close geographic proximity and will be served by a contiguous gas main infrastructure. In cases where the Company's rate of return criterion is met, the Company will provide the extension of gas main at no charge. In cases where this criterion is not met, the customer will be required to make up the capital deficiency (a "Contribution in Aid of Construction" or "CIAC") to meet the Company's rate of return criterion. The Company has developed a rate of return model ("Model") to be used for this analysis. The underlying rate of return criterion requires that each new installation project create sufficient revenues to earn the Company its after-tax weighted-average cost of capital to provide recovery of Incremental Project Costs (capital expenditures for services and/or main extensions, net of fixed General and Engineering and Operations overhead expenses) over a period of 20 years or less for residential and municipal projects and over a period of 10 years or less for commercial and industrial projects. (The recovery periods are considered 'dynamic' in the sense of commencing after the last year of construction, which may be appropriate to larger, multi-year construction projects.) If a project yields a rate of return equal to or greater than the benchmark rate of return over the benchmark recovery period, the project passes the rate of return test and no customer contribution is required. If a project fails the rate of return test, the Model calculates a CIAC required for the project to pass the rate of return test over the recovery period. Customer revenues used to calculate the Company's rate of return include distribution revenues only.

Q. Is calculating a CIAC an exact science?

A. It is not, although the Company is confident that the Model it uses to calculate a CIAC is a sound and conservative estimating tool that facilitates prudent decision-making. For reasons beyond the Company's control, circumstances may change during project construction in a manner that affects assumptions underlying the CIAC calculation. For example, the Company may encounter ledge when installing the extension, increasing the construction budget. In such a situation, a remodeling of the project economics might result in a higher CIAC than was collected from the customer. This was the case with the Atlantic Avenue and Hampshire Road projects. However, it is also the case that some extension projects result in better project economics than originally modeled which results in additional benefit to existing ratepayers.

Q. When the economics of a project change in a way that would result in a higher CIAC if the project were remodeled, does the Company request an additional CIAC amount from the customer?

A. The Company may do so, but believes it is important to be able to exercise judgment and discretion when remodeling a project results in a higher CIAC than was originally collected from the customer. In some circumstances – for example, if decisions unilaterally made by the customer change the project economics – then requesting an additional CIAC may be appropriate. But there may be other situations in which circumstances beyond the control of the Company and the customer cause a project to be less economic than originally modeled. Such circumstances may include unanticipated field conditions, or regulatory, State, or municipal requirements that could not reasonably be foreseen. When this is the case, the Company should have the flexibility to forego seeking an additional CIAC amount or, alternatively, negotiate an additional CIAC amount, as not all customers will have the financial ability to pay an additional CIAC amount, or requesting an additional CIAC may be unfairly burdensome to the customer in light of the customer's settled expectations.

When considered in the context of a portfolio of projects that returns net benefits to all customers, it is appropriate and reasonable to allow the Company full recovery of projects that may not be, in hindsight, as economically beneficial as anticipated. It would not be reasonable to subject the Company to a disallowance when it makes a prudent investment decision, encounters circumstances beyond its control, and determines that it would be unfairly burdensome to the customer to request an additional CIAC.

Q. Please briefly describe the Atlantic Avenue and Hampshire Road projects.

A. The School Administrative Unit 21 (SAU 21) requested gas service to the N. Hampton Elementary School which serves grades K-8th for the town of N.

Hampton. The SAU wanted to replace old inefficient oil boilers with new high-efficient natural gas boilers. To provide gas service the Company needed to install 3,200 feet of 6”8 HDPE gas main to the North Hampton Elementary School. This was tied into an existing 6” IP main in Atlantic Ave. The original IRR modeling for this project required a CIAC ($110,841) from the SAU. The town of N. Hampton was required to put this cost before the town in the form of a Warrant Article. The Article was passed and the project moved forward.

The Hampshire Road project was a new storage facility being constructed at 10 Hampshire Road in Salem, NH in which the customer requested natural gas to be extended enabling a new service connection to the site. To serve the property, the Company needed to install 300 feet of new 6” HDPE gas main to a point where a service could be extended onto the property. The new gas main was connected to the existing 6” IP main in Hampshire Road. The original modeling review for this project passed the necessary hurdle rate and required no CIAC from the customer.

Q. Did the Company remodel the Atlantic Avenue and Hampshire Road projects for this filing?

A. Yes, please see Schedule CGDN-5 for summary of the original model results and the revised model results. The additional projects included in this schedule will be explained later in our testimony.

Q. Did the Company update the results?

A. For the Atlantic Avenue project, modeling based on actual cost, currently connected customers, customers under contract, and the initial CIAC charged and collected returns a negative Net Present Value of ($110,276). However, there are an additional 21 potential customers (5 commercial, 16 residential) along the main extension that may connect over the coming years which would further improve the project economics. The revised modeling for the Hampshire Road project results in a Net Present Value of ($38,502). However, there are two more potential customers (1 commercial, 1 residential) that may connect along this main route and would improve the project economics in the future.

Q. What were the circumstances that caused the actual costs to be higher than originally estimated for the Atlantic Avenue project?

A. The cost increased due to ledge removal and additional cut backs and paving required by the New Hampshire Depart of Transportation ("NHDOT"). Ledge removal and the close proximity of the installed main to the edge of pavement undermined the pavement, and the NHDOT required the Company to cut the trench back one foot and repave. This requirement necessitated more paving and ledge removal than estimated.

Q. What were the circumstances that caused the actual costs to be higher than originally estimated for the Hampshire Road project?

A. The cost increased due to costs associated with additional ledge incurred at the street crossing. Although the Company originally planned to bore under the roadway, the ledge encountered in the street prevented that approach and required that the Company to open cut the street, remove ledge and cutback and pave the trench. This added additional traffic detail costs as well.

Q. Please explain why the full cost of the two main extension projects temporarily disallowed in the previous step filing should now be included in the Company's rate base.

A. The Company believes that main extension projects, when viewed in aggregate, will generally provide a benefit to the existing customer base. The Company relies on estimates that are reasonable and made in good-faith when analyzing the economics of a project during the planning process. Moreover, the planning process is designed to benefit rate payers. That is, if a project is not expected to meet or exceed the Company's hurdle rate during the planning phase, a CIAC is calculated to offset the capital costs and bring the economics in line. Conversely, if the project economics exceeds the Company's hurdle rate the benefit will be recognized by the existing rate payers as the Company's fixed costs are spread over a larger customer base. These two scenarios illustrate that there is a strong rate payer protection built into the main extension policy that allows existing customers to reap the benefit of projects while mitigating the risk of weaker projects with a CIAC. This built in rate payer protection ensures that extension projects, in aggregate, will benefit the existing rate payers.

Schedule CGDN-5 summarizes the original and revised net present value of the nine main extension projects included in the Company's 2019 step filing, and illustrates that the projects, when reviewed in aggregate, benefit the existing customer base. The Company updated the original models for actual capital costs, actual customer additions, and updated estimated usage based on recent billing data. This was a conservative update process as the Company did not update for distribution rates that have increased, nor did the Company update for the lower hurdle rate as a result of declining cost of debt. This Schedule illustrates that the total projects return a favorable Net Present Value of $914,129, an increase of $562,718 over the original estimates. While some projects are not as strong as originally estimated, in aggregate, the main extensions provided a significant net benefit to existing customers of over $0.9 million.

Q. Does the Company believe it is appropriate to continue to disallow rate base denied in the previous step adjustment?

A. No. The Company's gas extension projects proposed for recovery in the prior step filing have proven to be beneficial to existing rate payers, demonstrating the Company's prudent judgement and discretion during the project evaluation phase. By penalizing the Company on a project by project basis the Commission would markedly increase the financial risk of the Company's expansion projects, which provide a net benefit to all rate payers. The Company's main extension projects are properly planned and prudent investments that warrant a fair return on invested capital.

4. EPPING FRANCHISE EXPANSION

Q. Has the Company provided a variance analysis comparing the results of the DCF analysis of the Company's Epping Franchise Expansion (Docket No DG 18-094) to an updated DCF analysis?

A. Yes. Please see Schedule CGDN-6. As directed by the Commission in Docket No DG 18-094, the Company has provided a variance analysis comparing the original DCF analysis for the Epping franchise (DG 18-094 Hearing Exhibit 8) and a revised DCF analysis using actual costs and revenues and projected future revenues. DG 18-094, Order No. 26,220 at 12 (Feb. 8, 2019).

Q. Please explain the update process for the Revised DCF model.

A. The Company updated the original model referenced as Exhibit 8 for actual project costs and actual customer additions. The Company maintained its previous assumptions for total market size and customer conversion rate. The remaining modeling logic for revenue, expense, and the cash flow discounting methodology is also unchanged.

Q. Please compare the results of the original and revised DCF model.

A. Actual capital costs are similar to the original cost estimates, increasing less than 4.0%. The revised 10-year and 20-year net present values have been provided in Schedule CGDN-6.

Q. Will Northern's expansion into Epping be beneficial for its existing customers in New Hampshire?

A. Yes. The Company is pleased with the development of the project and believes the project will benefit existing rate payers and the town of Epping. The 20-year net present value is very strong, emphasizing that this project will benefit rate payers for decades to come. The town of Epping has experienced impressive commercial growth over the past decade, and the Company expects development in the area to further support the economics of the expansion. Furthermore, the pipelines installed in Epping have sufficient capacity to serve other communities should the Company continue to expand its distribution network.

VII. TRANSITION TO DECOUPLING

Q. How will the Company transition from Lost Base Revenue Recovery as part of the Lost Revenue Rate ("LRR") to Decoupling?

A. At the start of the proposed decoupling period of August 1, 2022, the Company will stop accruing Lost Base Revenue ("LBR") associated with Energy Efficiency savings. Up until that time, the Company will continue to collect and accrue LBR associated with the 2020 energy efficiency savings, the 2021 energy efficiency savings and the 2022 energy efficiency savings through July 31, 2022, assuming a start date of decoupling of August 1, 2022. Table 3 below outlines how the transition will work based on the proposed temporary rates, permanent rates and decoupling start period of August 1, 2022 timeline. The Company is not proposing any change to the LRR at this time and instead will make all required changes, including reconciliations in subsequent LRR filings as appropriate.

Table 3: Transition from LBR to Decoupling

October 1, 2021 (Temporary Rates Effective)
Stop accruing lost revenue associated with the 2017 savings
Stop accruing lost revenue associated with the 2018 savings
Stop accruing lost revenue associated with the 2019 savings
Continue accruing lost revenue associated with the 2020 savings*
Continue accruing lost revenue associated with the 2021 savings
January 1, 2022 to August 1, 2022
Continue accruing lost revenue associated with the 2020 savings*
Continue accruing lost revenue associated with the 2021 savings
Continue accruing lost revenue associated with the 2022 savings
August 1, 2022 (Permanent Rates Effective - Begin Decoupling)
Stop accruing lost revenue associated with the 2020 savings*
Stop accruing lost revenue associated with the 2021 savings
Stop accruing lost revenue associated with the 2022 savings
*Taking into account timing of the month of installtion for the 2020 measures

Q. Why will the Company continue to accrue lost revenue associated with the 2020 measures if 2020 was the test year?

A. The Company needs to continue to recover lost revenue associated with the savings reduction not reflected in the 2020 test year. For example, for a measure that was installed in December 2020 that is estimated to save 120 therms annually, the impact on the 2020 test year sales would only reflect a reduction of 10 therms kWh (120 / 12 months * 1 month). The remaining 110 therms of savings would be realized in 2021, so it is necessary to continue to recover lost revenue associated with the 2020 savings, taking into account the month that savings were realized in 2020. Table 4 below shows an illustrative example of how the calculation would work based on the 145,178 therms of actual annual 2020 savings installed in 2020. The 2020 test year would reflect a reduction in sales of 65,169 therms with the remaining reduction of 80,008 therms of savings reduction occurring in 2021.

Table 4: Illustrative 2020 Savings Annualization

Northern Utilities, Inc.
2020 Residential Installed Therm Savings
Savings Annualization

Line	Description	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	2020 Annual Savings
	Col. A	Col. C	Col. D	Col. E	Col. F	Col. G	Col. H	Col. I	Col. J	Col. K	Col. L	Col. M	Col. N	Col. O
1	**Monthly Residential Therm Savings***	**-**	**16,204**	**15,242**	**7,355**	**918**	**4,876**	**3,827**	**30,944**	**14,644**	**24,534**	**7,203**	**19,430**	**145,176**
2														
3	**Monthly Residential Therms Savings**													
4	January 2020	-	-	-	-	-	-	-	-	-	-	-	-	-
5	February 2020		1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	1,350	14,853
6	March 2020			1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	1,270	12,702
7	April 2020				613	613	613	613	613	613	613	613	613	5,516
8	May 2020					76	76	76	76	76	76	76	76	612
9	June 2020						406	406	406	406	406	406	406	2,844
10	July 2020							319	319	319	319	319	319	1,913
11	August 2020								2,579	2,579	2,579	2,579	2,579	12,893
12	September 2020									1,220	1,220	1,220	1,220	4,881
13	October 2020										2,044	2,044	2,044	6,133
14	November 2020											600	600	1,201
15	December 2020												1,619	1,619
16	**Total 2020 Therm Savings Realized in 2020**	**-**	**1,350**	**2,621**	**3,233**	**3,310**	**3,716**	**4,035**	**6,614**	**7,834**	**9,879**	**10,479**	**12,098**	**65,169**
17														
18	**2020 Residential Therm Savings Realized in 2021**	**-**	**1,350**	**2,540**	**1,839**	**306**	**2,031**	**1,913**	**18,051**	**9,762**	**18,400**	**6,003**	**17,811**	**80,008**

*Per DE 17-136 Northern Utilities, Inc 2020 Energy Efficiency Revised Annual Report filed on June 29, 2021 Page 1 of 18(Revised)

VIII. PROPOSED TARIFF CHANGES

Q. Please summarize the proposed tariff changes presented in the Company's filing.

A. The Company's proposed tariff changes reflect: (1) the proposed rates, as presented in the prefiled testimony of Ron Amen and John Taylor; (2) the proposed Revenue Decoupling Adjustment Clause as presented in the prefiled testimony of Timothy Lyons; (3) proposed changes to the Company's proposed RCAM tariff, which is a component of the LDAC; (4) proposed Temporary Rate surcharge; and (5) changes to the Company's delivery service terms and conditions as supported by Mark Lambert.

Q. What changes is the Company proposing to the Company's proposed RCAM tariff?

A. The Company is proposing changes to its proposed RCAM tariff to address the following:

1. As described above in Section III. C. ii. 3, the Company is proposing to track the actual delivery write offs against the level in distribution rates and to recover the difference annually as part of the subsequent year's RCAM.
2. The Company is proposing to track the actual annual cost of the AMP and reconcile the cost annually against the amount that is included in base distribution rates. Any variance from the level in distribution rates will be deferred and refunded or recovered as part of the subsequent years RCAM. This is described in greater detail in Section III. C. ii. 13 above.
3. As described in Section VI. 1 above, the Company is proposing to collect the late payment fees the Company would have charged to customers if the late payment fee prohibition was not in place through the subsequent year's RCAM.
4. As described in Section VI. 1, the Company is proposing to refund or collect the change in special contract revenues from the amount included in base distribution rates through the subsequent year's RCAM.

Finally, the Company is not proposing any change to the RCAM rate at this time, and instead will make all required changes, including reconciliations in subsequent RCAM filings as appropriate. The Company has provided an illustrative RCAM tariff, which is a component of the LDAC in Schedule CGDN-7 to reflect the changes from the RCAM tariff proposed in Docket No. DG 21-123.

Q. Has the Company prepared revised tariffs?

A. Yes. The clean and red-lined versions of the proposed tariff changes have been provided as a part of this filing.

Q. Are there any other tariff changes resulting from this case?

A. Yes. Northern will file a rate case surcharge rate at the conclusion of this proceeding to recover rate case costs and the recoupment and reconciliation of temporary and permanent rates when the final amounts are known.

IX. RATE CASE EXPENSES

Q. How do you propose to recover rate case expenses?

A. Northern proposes to file a rate case surcharge to recover the costs incurred to plan, develop and present this rate case to the Commission at the conclusion of this proceeding when the final dollar amount of these expenses is known. A projection of these costs is detailed in Schedule RevReq-7.

Q. How do you propose to structure the rate case expenses surcharge?

A. The rate case expenses surcharge will be a charge per therm, applied to all rate schedules, and included in the LDAC. Subject to Commission approval, the charge will be a temporary charge, and will be set at a level to recover the costs over a one-year period. The revenue collected will be fully reconciled with the costs incurred. At the end of the recovery period, the Company would file with the Commission a reconciliation of the surcharge, including a recommendation for treatment of any under- or over-recovered balances projected to remain at the end of the surcharge account.

Q. Please provide the estimated amount of rate case costs.

A. The estimated costs to be incurred for the rate case are $735,000 and are detailed on Schedule RevReq-7.

Q. How does the Company account for rate case costs?

A. The Company defers all costs associated with the case as they are incurred during the course of the proceeding for future recovery in rates. The Company will be prepared to provide the Commission with documentation to support those costs eligible for recovery. This documentation will consist of copies of invoices and/or other information that will assist the Commission with its review.

Q. Will the Company inform the Commission about its actual rate case costs throughout this proceeding?

A. Yes, every 90 days the Company will file with the Commission the items required by Part Puc 1905.01 (a) of its rules.

X. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

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