February 12, 2024

Daniel Goldner, Chairman
New Hampshire Public Utilities Commission
21 S. Fruit St., Suite 10
Concord, New Hampshire 03301

RE: Docket No. DG 23-086, Revenue Decoupling Adjustment Factor Rebuttal Testimony of Northern Utilities, Inc.

Chairman Goldner,

In connection with the above-referenced matter, please find enclosed the Rebuttal Testimony of Northern Utilities, Inc. ("Unitil" or the "Company"). The Company's Rebuttal Testimony responds to the Technical Statements submitted by the New Hampshire Department of Energy (the "Department"). The Department's technical statements depart materially from the Settlement Agreement approved by the Commission in DG 21-104.

In its initial filing in DG 21-104, Unitil proposed a revenue decoupling mechanism that implements a "revenue per customer" ("RPC") methodology. The Company, the Department, and the Office of the Public Advocate (collectively, the "Settling Parties") negotiated and entered into a Settlement Agreement in which the Settling Parties agreed that Unitil would implement a revenue decoupling mechanism "substantially as proposed" in the Company's initial filing. The Settlement Agreement unambiguously sets forth the agreement of the Settling Parties that Unitil would implement an RPC revenue decoupling model that reconciles monthly actual and authorized RPC by rate class. The method for calculating the Revenue Decoupling Adjustment ("RDA") and Revenue Decoupling Adjustment Factor ("RDAF") is set forth in detail in the Settlement Agreement. The Commission, after conducting a hearing, approved the Settlement Agreement and, again, unambiguously explained that the Company would use an RPC model and described in detail how the model will work. DG 21-104, Northern Utilities, Inc., Order No. 26,650 at 4-6 (July 20, 2022).

On September 15, 2023, Unitil filed, pursuant to Order No. 26,650 and NHPUC No. 12 – Gas First Revised Pages 163-168, its Petition for approval of the Company's

Patrick Taylor
Chief Regulatory Counsel
taylorp@unitil.com

6 Liberty Lane West
Hampton, NH 03842

T 603.773.6544
www.unitil.com

Unitil

proposed RDAF for effect November 1, 2023. The Settling Parties agreed on a process in which the Company would make an annual RDAF filing on September 15 for rates effective November 1. The Company's RDA and RDAF are calculated in the manner set forth in the Settlement Agreement, Order 26,650, and the Company's tariff. Despite the fact that the Company submitted a timely filing consistent with the terms of the DG 21-104 Settlement Agreement and the applicable Commission-approved tariff, Unitil assented to the Department of Energy's October 10, 2023 request for additional time to conduct discovery on the Company's filing.

On December 8, 2023, the Department submitted a technical statement to the Commission. In that technical statement, the Department declined to offer a position on the Company's filing, stating instead that its "current position and recommendation is that the Commission review and continue its conditional approval of Northern's capped RDAF claim . . . subject to: the pending discoveries from Northern; and future updated filing to be submitted by the Department upon review of . . . pending information." On December 22, 2023, Unitil sought an opportunity to submit rebuttal testimony at a time after the Department provided a supplemental technical statement. On January 5, 2024, the Commission approved an amended procedural schedule providing the Department an opportunity to submit a supplemental technical statement by January 25, 2024 and the Company the opportunity to provide rebuttal by February 12, 2024.

On January 25, 2024 the Department submitted a supplemental technical statement that is extensively critical of the very RPC method to which the Department agreed in the Settlement Agreement and that the Commission approved in Order 26,650. Though the Department does not dispute that Unitil calculated the RDA and RDAF correctly and as prescribed in the Settlement Agreement, Order 26,650, and the Company's Tariff, it nevertheless attempts to dispute and litigate the legitimacy of the RPC method and recommends a disallowance of approximately $1.15 million based on an alternative decoupling approach to which the Settling Parties did not agree.

The Department conducted extensive discovery in DG 21-104, submitted testimony, negotiated the Settlement Agreement (as well as a settlement in DE 21-030 with an identical RPC revenue decoupling mechanism), and had the benefit of a hearing before the Commission. To the extent that the Department was critical of the RPC method, it had ample opportunity to raise those concerns in DG 21-104. Instead, the Department agreed to implement the RPC revenue decoupling method substantially as proposed in

Patrick Taylor
Chief Regulatory Counsel
taylorp@unitil.com

6 Liberty Lane West
Hampton, NH 03842

T 603.773.6544
www.unitil.com

Unitil's initial filing. It is not appropriate to now disavow the RPC method and recommend a disallowance that is entirely inconsistent with the DG 21-104 Settlement Agreement, Order 26,650, and the Company's tariff. To allow this departure from the approved Settlement Agreement would be contrary to the well-established Commission policy encouraging parties "to settle disagreements through negotiation and compromise because it is an opportunity for creative problem solving, allows parties to reach a result in line with their expectations." Order 26,650 at 12. The Department's supplemental technical statement is not in line with the settled expectations of the parties to DG 21-104.

Even assuming, for the sake of argument, that the Commission were to consider the Department's arguments notwithstanding their inconsistency with Order 26,650, they are not appropriate for consideration in this docket. The Settlement Agreement, Order 26,650, and the Company's Tariff set forth a method for calculating the RDA and RDAF; to the extent the RDA exceeds a cap of 4.25 percent of approved distribution revenues for each group over the relevant measurement periods for over- and under-recoveries, the amount over or under 4.25 percent shall be deferred, with carrying costs accrued monthly at the Prime Rate. Order 26,650 at 14. The specific treatment of any remaining carried balances is to be addressed in the Company's next rate case. Id. at 6. To the extent that the Department wishes to revisit the RPC method, it may do so in the Company's next distribution rate case.

Thank you for your assistance with this matter.

Regards,

Patrick H. Taylor

Patrick Taylor
Chief Regulatory Counsel
taylorp@unitil.com

6 Liberty Lane West
Hampton, NH 03842

T 603.773.6544
www.unitil.com

NORTHERN UTILITIES, INC.

REBUTTAL TESTIMONY

OF

S. ELENA DEMERIS AND DANIEL T. NAWAZELSKI

PETITION FOR APPROVAL OF

REVENUE DECOUPLING ADJUSTMENT FACTOR

New Hampshire Public Utilities Commission

Docket No. DG 23-086

I. INTRODUCTION

a. S. Elena Demeris

Q. Please state your name and business address.

A. My name is S. Elena Demeris. My business address is 6 Liberty Lane West, Hampton, New Hampshire.

Q. For whom do you work and in what capacity?

A. I am a Senior Regulatory Analyst for Unitil Service Corp. ("Unitil Service"), a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's principal subsidiaries Fitchburg Gas and Electric Light Company, d/b/a Unitil ("FG&E"), Granite State Gas Transmission, Inc. ("Granite"), Northern Utilities, Inc. d/b/a Unitil ("Northern"), and Unitil Energy Systems, Inc. ("UES") (together "Unitil"). In this capacity I am responsible for preparing regulatory filings, pricing research, regulatory analysis, tariff administration, revenue requirements calculations, customer research, and other analytical services.

Q. Please summarize your professional and educational background.

A. In 1996, I graduated from the University of Massachusetts - Lowell with a Bachelor's of Science Degree in Civil Engineering. In 2005, I earned a Master's Degree in Business Administration and in 2006 a Master's Degree in Finance from Southern New Hampshire University. I joined Unitil in July 1998 in the regulatory/rate department.

b. Daniel T. Nawazelski

Q. Please state your names and business address.

A. My name is Daniel T. Nawazelski, and my business address is 6 Liberty Lane West, Hampton, New Hampshire 03842.

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

A. I am the Manager of Revenue Requirements for Unitil Service Corp. ("Unitil Service") a subsidiary of Unitil Corporation that provides managerial, financial, regulatory and engineering services to Unitil Corporation's utility subsidiaries including Northern Utilities, Inc., which has operating divisions in New Hampshire and Maine (the New Hampshire operating division is hereinafter referred to as "Northern" or the "Company"). In this capacity I am responsible for the preparation and presentation of distribution rate cases and in support of other various regulatory proceedings.

Q. Mr. Nawazelski, please describe your business and educational background.

A. I began working for Unitil Service in June of 2012 as an Associate Financial Analyst and have held various positions with increasing responsibilities leading to my current role of Manager of Revenue Requirements. 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. I am also currently pursuing my Masters in Business Administration at the University of New Hampshire.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this rebuttal testimony is to address the Department of Energy's ("Department") comments on the Company's revenue decoupling filing as stated in the Department's technical statements. The Department's comments include several observations regarding the Company's filing that are inaccurate, are entirely inconsistent with the Settlement Agreement that the Department entered into in DG 21-104, and incorrectly and inappropriately seek to cap earnings at the Company's revenue test year amount.

Q. Please describe the Revenue Per Customer revenue decoupling model approved by the Commission in DG 21-104.

A. In DG 21-104, Unitil, the Department of Energy, and the Office of the Consumer Advocate (collectively, the "Settling Parties") entered into a negotiated settlement agreement in which the Settling Parties agreed that Unitil would implement a revenue decoupling mechanism "substantially as proposed in the initial prefiled testimony of Unitil witness Timothy Lyons," subject to certain adjustments specified in the Settlement Agreement. Specifically, the Settling Parties agreed that Unitil would implement a Revenue Per Customer ("RPC") revenue decoupling model that reconciles monthly actual and authorized RPC by rate class. The relevant portions of the Settlement Agreement describing the agreed-upon revenue decoupling model, including Attachment 3 to the Settlement Agreement setting forth the monthly RPC targets, are provided as Attachment 1 to this testimony. The initial prefiled testimony of Mr. Lyons and accompanying schedules were included in the DG 21-104 evidentiary record as a part of Hearing Exhibits 3 (Redacted) and 14 (Confidential) (Bates 001143 – 001181).

The Commission approved the Settlement Agreement, including the RPC revenue decoupling model, in DG 21-104, Northern Utilities, Inc., Order Approving Settlement Agreement at 4-6, 13-14, 21 (Order 26,650, July 20, 2022). In its Order, the Commission explained the RPC model:

> The Settlement provides that Northern shall implement the RDM as follows. First, the Company shall record monthly variances between actual and authorized RPC for each rate class. Rather than record and reconcile the variances on an annual basis, the variances would be recorded and reconciled separately, for the Peak (November through April) and Off-Peak (May through October) periods (the Measurement Periods). The monthly variances in the applicable Measurement Period would then be totaled by class.
>
> The total variances by customer class group and carrying costs shall form the basis for the revenue decoupling adjustment (RDA) by group and the calculation of revenue decoupling adjustment factors (RDAF) (surcharges or credits). A Customer Class Group comprises the rate schedules combined for purposes of calculating the RDA amounts. The four Customer Class Groups shall be: (1) Residential Heating (R-5 and R-10); (2) Residential Non-Heating (R-6); (3) C&I High Load Factor (G-50, G-51, G-52); and (4) C&I Low Load Factor (G-40, G-41, G-42).
>
> Second, the Company shall annually file with the Commission the applicable RDAF 45 days in advance of November 1. The filing will provide the proposed RDAF for the Peak period, for effect November 1, and subsequent Off-Peak period, for effect May 1. The RDA for the Peak period shall reflect actual data for the entire six-month period while the RDA for the Off-Peak period shall reflect actual data for the first three months of the period and estimated data for the remaining three months. The filing shall include the RDA by group, including prior period reconciliation and calculation of the RDAF. Pursuant to this Settlement Agreement, rather than reconcile the RDA on an allocated basis as initially proposed by Northern, the Company shall reconcile the RDA using the four customer class groups defined above. The RDAF shall be calculated as a dollar-per-therm charge or credit based on the RDA for each group divided by the projected therm sales for each group over the prospective six-month period November through April and May through October (the RDM Adjustment Period). The RDAF shall be charged or credited to customer bills during the RDM Adjustment Period.
>
> Northern shall implement an RDA cap of 4.25 percent of approved distribution revenues for each group over the relevant Measurement Period(s) for over- and under-recoveries. To the extent that the RDA for a group,

> including prior period reconciliation exceeds 4.25 percent of distribution revenue, the amount over or under 4.25 percent shall be deferred, with carrying costs accrued monthly at the Prime Rate with said Prime Rate to be fixed on a quarterly basis and to be established as reported in *The Wall Street Journal* on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used.

Order 26,260 at 4-6. The Department similarly agreed to a substantively identical RPC revenue decoupling method for Unitil Energy Systems, Inc. in DE 21-030, and the Commission approved the settled-upon method without modification. DE 21-030, Unitil Energy Systems, Inc., Hearing Exhibit 12 (Settlement Agreement and Attachments) at Bates 000006-07; DE 21-030, Unitil Energy Systems, Inc., Order Approving Settlement Agreement at 24-25, 32 (Order No. 26,623, May 3, 2022). We also note that a similar RPC revenue decoupling mechanism has been in place for Northern's Massachusetts affiliate, Fitchburg Gas and Electric Light Company, for over twelve years. See DPU 11-02, Fitchburg Gas and Electric Light Company, Final Order at 114 – 127 (MA DPU August 1, 2011).

Q. Did the Company calculate the RDA and RDAF consistent with the Settlement Agreement and the Commission's Order in DG 21-104?

A. Yes. Pre-Filed Testimony of S. Elena Demeris and the accompanying attachments set forth the calculation of the RDA and the RDAF, calculation of the RDAF (Page 1), reconciliations by customer group and period, calculations supporting the development of the monthly revenue variances by class group and period, the calculation of the revenue cap, actual base revenue for the period, and forecasted revenues.

Q. The Settling Parties in DG 21-104 agreed that Northern would implement an RPC decoupling model. Why did the Company propose an RPC approach in DG 21-104?

A. As the Company explained in its initial filing in DG 21-104, the primary benefit of the proposed RPC approach is the recognition of new customer revenues. The Company expects to add new customers and incur incremental costs to serve new customers during the term of the revenue decoupling mechanism. The incremental costs are related to providing new customers with access to the distribution system and meeting their demand requirements. Under the RPC approach, the Company retains the RPC associated with serving new customers that is used to offset the costs associated with new customers.

By comparison, under a "total revenue" approach to decoupling, the Company does not retain incremental revenues to offset the incremental costs, creating an adverse financial impact when adding new customers. The distinction between the RPC and total revenue approaches was explained in the pre-filed Testimony of Timothy Lyons in DG 21-104. The Company has provided this testimony as Attachment 2 for ease of reference. See Page 12 of 22 for the clear explanation of the proposed type of Revenue Decoupling Mechanism and the Company's reasoning for choosing that approach.

Q. How would a "total revenue" approach to revenue decoupling be applied?

A. Under the total revenue approach, the approved target revenue by rate class is set and annually reconciles to that approved total revenue. A company does not retain incremental revenues to offset the incremental costs, creating an adverse financial impact when adding new customers under this revenue decoupling mechanism methodology.

Total revenue RDM's are oftentimes accompanied by capital trackers that provide timely recovery on all (growth and non-growth) investments that help maintain the financial health of the company.

The RPC and total revenue approaches are not interchangeable. When determining whether to apply an RPC or total revenue approaches there are a multitude of things to consider. The merits and considerations of both were contemplated by the Company during the Company's base rate case proceeding in DG 21-104.

Q. The Department of Energy appears to recommend a disallowance of $1,145,894, asserting that it is "additional" to the Company's "approved revenue requirement" of $47,673,687. Is the Department's position consistent with the Settlement Agreement?

A. No. The Department is effectively arguing that the Commission should disregard the RPC approach to which the Settling Parties agreed, and the Commission approved, and instead impose a "total revenue" approach. As explained above, the total revenue approach is fundamentally inconsistent with the RPC approach, and the Department's recommended disallowance is inconsistent with the express terms of the Settlement Agreement and Order 26,650.

Q. The Department offers "observations" that are critical of the RPC method at pages 8-10 of the Supplemental Technical Statement. Do you agree that the RPC decoupling method creates "multiple misalignments"?

A. No. As an initial matter, the RPC method was proposed in the Company's initial filing in DG 21-104, supported by testimony with multiple schedules and an illustrative calculation. The Company's proposal was subject to discovery, technical sessions, the opportunity for testimony by Department and the OCA, and, ultimately, a negotiated Settlement Agreement and a hearing before the Commission. The Company has calculated its RDA and RDAF exactly in the manner set forth in the Settlement Agreement and Order 26,650. Northern notes that the Department repeatedly characterizes the output of this calculation as the Company's "ask" in this case; the Company believes this is an inaccurate characterization, as the calculation was agreed to by the Settling Parties and approved by the Commission, and the Company has stated the objective outcome of the calculation. The Department has not asserted that the calculated RDA, including the deferred amount over the cap, is inaccurate.

Addressing the Department's "observations," the Company responds as follows:

The Department's December 8, 2023 Technical Statement repeatedly stated, incorrectly, that the Company's Actual Customer Charge Revenue includes estimated components. This is not the case. Actual Customer Charge Revenue used in the RDAF filing, and as consistent with the presentation in DG 21-104, is based on actual customer charge revenue from the Company's billing system and includes no estimated components.

The Company also addresses the Departments January 25, 2024 Technical Statement as follows:

3: *"In DOE's initial technical statement, for a well-functioning RPC decoupling structure, the Department observed the importance of customer count methodology, the data normalization process, and the utility accounting practices. Informed by Northern's* *response to DOE Set 3, it appears that the Company's current billing system is unable to provide key information necessary to analyze the RDAF ask."*

Response: As repeatedly explained by the Company throughout the discovery phases, the Company's RDAF filing and decoupling structure was calculated entirely consistent with the approved Settlement Agreement in DG 21-104. This consistency also applies to the customer count methodology and accounting practices. The Company's current billing system provides all of the necessary information to analyze and review the Company's RDAF filing. The Department's perceived lack of key information pertains to analysis that is entirely out of scope of the Company's approved revenue decoupling mechanism and applicable tariff.

5.3: *"As such, the underlying premise, and an inherent part of the ensuing Revenue Decoupling Mechanism (RDM) was to correct the misalignment by adjusting the Company's actual revenues to match its authorized revenue."*

Response: The Department has correctly stated the underlying premise of revenue decoupling, but declines to acknowledge the different methodologies of full decoupling mechanisms, which as described in Attachment 2 can calculate variances based on the basis of total revenues, or revenue per customer. As described throughout our rebuttal testimony the Settling Parties unambiguously agreed to implement a revenue per customer method, and the Commission unambiguously approved the revenue per customer method.

5.4: *"Northern's authorized revenue in DG 21-104 was $47,673,687. . . . As such, the proposed RDM principles dictate that Northern should be allowed to collect up to the* *approved authorized revenue amount $47,673,687. Any additional revenue beyond the authorized amount could unduly harm the other party, namely the ratepayers."*

Response: The Department's characterization of the "RDM principles" and the purported harm to ratepayers are not correct. First, the Department, the OCA, and the Commission reviewed the RPC method – which the Company has followed precisely - and found it to be just and reasonable. Second, as explained above, the RPC method is intended to recognize new customer revenues and retain the RPC associated with serving new customers that is used to offset the costs associated with new customers. Imposing a cap based on the "authorized revenue" is fundamentally inconsistent with the RPC method and nothing in the Settlement Agreement states that such a cap must be imposed. The Department's recommendation is a clear departure from the Settlement Agreement and will be prejudicial to the Company.

5.5: *For the Decoupling Year (DY1) under consideration, Northern reported to have earned a total base revenue of $44,506,322. . . . Northern also reported and is seeking a total of $4,313,259 in RDAF. This RDAF ask implies, if the requested amount is approved for eventual collection in base distribution revenues, that Northern would recover a total of $48,819,581 in DY1. This is would be $1,145,894 . . . additional to the approved revenue requirement. It is also unclear if, due to the application of the current RPC formula, this additional $1.15 million revenue was intended to be provided to the Company under the proposed RDM. Consequently, if the requested total RDAF amount ($4.3 million) is approved, the ratepayers would be unduly harmed by this additional $1.15 million RDAF ask.*

Response: The Settlement Agreement and Order 26,650 unambiguously set forth the RPC revenue decoupling method and calculation of the RDA and RDAF. The intent of the Settling Parties and the Commission is clear and expressed in the plain language of the Settlement Agreement. Northern is not requesting an “additional” $1.15 million above the Company’s approved revenue requirement. The Commission approved a RPC revenue decoupling method in Order 26,650, and the RDA calculated in this case is consistent with that method as described in the Order. The full amount of the RDA is what the Commission approved in DG 21-104. Under the approved RPC approach the Company is allowed to retain the RPC with serving new customers. As Attachment 3 shows, the entire amount of additional revenue is associated with new customer revenue with approximately 95 percent of that growth occurring within the R-5 and R-10 residential heating classes. This shows that the Company’s agreed to and approved revenue decoupling mechanism approved in DG 21-104 is working exactly in the manner intended.

5.7: *The per customer RDAF structure creates multiple misalignments* . . . .

Response: The Department’s arguments in this paragraph are largely repetitive of previous assertions in the technical statement and completely disregard the express terms of the Settlement Agreement that the Settling Parties, including the Department, negotiated, and that the Commission approved. We note that under the Settlement Agreement and Order 26,650, the treatment of deferred balances over the RDA cap is to be addressed in the Company’s next distribution rate case. See Attachment 1; Order No. 26,650 at 6. We understand the arguments set forth within paragraph 5.7 and throughout the Department’s technical statement to be outside the scope of this docket and more appropriately addressed in the Company's next rate case. The Company has not addressed these comments in paragraph 5.7 beyond what we have already stated in our testimony, but this should not be viewed as acceptance of any of the Department's conclusions.

Q. Do you believe the Commission should approve the proposed RDAF as filed?

A. Yes, the Department concludes in its comments that the Company has accurately calculated its revenue decoupling factors in accordance with the Settlement Agreement and the Company's tariff. The Department's suggestion that the Company's RDA, including the deferral balance over the cap, should be capped at the test year amount used to develop revenue per customer levels is erroneous, inconsistent with the RPC method approved in DG 21-104, and should be rejected.

Q. Does this conclude your testimony?

A. Yes, it does.

SECTION 4. REVENUE DECOUPLING MECHANISM

4.1 The Settling Parties agree that Unitil shall implement a Revenue Decoupling Mechanism ("RDM") substantially as proposed in the initial prefiled testimony of Unitil witness Timothy Lyons, subject to the adjustments specified in this Settlement Agreement. Specifically, the Settling Parties agree and recommend that the Commission approve a RDM using a Revenue Per Customer ("RPC") model that shall reconcile monthly actual and authorized RPC by rate class. Settlement Attachment 3 provides the Company's monthly target RPCs effective August 1, 2022 and also provides preliminary monthly target RPCs effective September 1, 2022 to reflect the 2022 Step Adjustment.

4.2 The Company shall implement the RDM as follows:

4.2.1 First, the Company shall record monthly variances between actual and authorized RPC for each rate class. Rather than record and reconcile the variances on an annual basis, the variances shall be recorded and reconciled separately, for the Peak (November through April) and Off-Peak (May through October) periods (the "Measurement Periods"). The monthly variances in the applicable Measurement Period shall then be totaled by class. The total variances by customer class group and carrying costs shall form the basis for the revenue decoupling adjustment ("RDA") by group and the calculation of revenue decoupling adjustment factors ("RDAF") (surcharges or credits). A Customer Class Group comprises the rate schedules combined for purposes of calculating the RDA amounts. The four Customer Class Groups shall be: (1) Residential Heating (R-5 and R-10); (2) Residential Non-Heating (R-6); (3) C&I High Load Factor (G-50, G-51, G-52); and (4) C&I Low Load Factor (G-40, G-41, G-42).

4.2.2 Second, the Company shall annually file with the Commission the applicable RDAF 45 days in advance of November 1. The filing will provide the proposed RDAF for the Peak period, for effect November 1, and subsequent Off-Peak period, for effect May 1. The RDA for the Peak period shall reflect actual data for the entire six month period while the RDA for the Off-Peak period shall reflect actual data for the first three months of the period and estimated data for the remaining three months. The filing shall include the RDA by group, including prior period reconciliation and calculation of the RDAF. Pursuant to this Settlement Agreement, rather than reconcile the RDA on an allocated basis as initially proposed by Unitil, the Company shall reconcile the RDA using the four customer class groups defined in subpart 4.2.1 above. The RDAF shall be calculated as a dollar per therm charge or credit based on the RDA for each group divided by the projected therm sales for each group over the prospective six-month period November through April and May through October ("the RDM Adjustment Period"). The RDAF shall be charged or credited to customer bills during the RDM Adjustment Period.

4.2.3 Unitil shall implement an RDA cap of 4.25 percent of approved distribution revenues as established by this Settlement for each group over the relevant Measurement Period(s) for over- and under-recoveries. To the extent that the RDA for a group, including prior period reconciliation exceeds 4.25 percent of distribution revenue, the amount over or under 4.25 percent shall be deferred, with carrying costs accrued monthly at the Prime Rate with said Prime Rate to be fixed on a quarterly basis and to be established as reported in *The Wall Street Journal* on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used. In the Company's next distribution rate case, parties to that proceeding may propose specific treatment of any carried balances remaining at that time.

4.2.4 The Settling Parties agree that the RDM shall be implemented at the proposed effective date of new permanent rates on August 1, 2022. At that time, Unitil shall cease accruing Lost Base Revenue ("LBR") due to energy efficiency and shall transition to decoupling as described in the August 2, 2021 Testimony of Christopher Goulding and Daniel Nawazelski at Bates pages 000111-113.

4.2.5 With respect to the treatment of special contract revenue, the Company shall not implement its proposal to reconcile test year special contract revenue with actual revenue. The Settling Parties agree that if any special contract customers become tariff customers, they will be excluded from the RDM.

SECTION 5. STEP ADJUSTMENT

5.1 For purposes of calculating the Step Adjustment, the following definitions shall apply:

5.1.1 Accumulated Depreciation is the cumulative net credit balance arising from the provision for depreciation expense, cost of removal, salvage, and retirements. Non-growth depreciation expense and retirements shall be apportioned to non-growth investments based upon the proportion of non-growth related Plant Additions relative to total Plant Additions in the Investment Year.

5.1.2 Change in Net Plant is the change in Net Utility Plant from one Investment Year to the next, which accounts for Plant Additions as well as Accumulated Depreciation.

5.1.3 Change in Growth Net Plant is the actual amount of growth-related Plant Additions in the Investment Year as set forth in Settlement Attachment 2 and Accumulated Depreciation. The amount of Depreciation Expense used in calculating Accumulated Depreciation is apportioned to growth-related Plant Additions based upon the proportion of growth-related Plant Additions relative to total Plant Additions in the Investment Year.

5.1.4 Change in Non-Growth Net Plant is the difference between the total Change in Net Plant less the Change in Growth Net Plant for the Investment Year.

5.1.5 Depreciation Expense is the return of the Company's investment calculated by multiplying the Non-Growth Additions by the average depreciation rate of 3.46 percent.

5.1.6 Externally Imposed Accounting Rule Change shall be deemed to have occurred if the Financial Accounting Standards Board or the Securities and Exchange

Northern Utilities, Inc. - New Hampshire Division
Decoupling
Target Distribution Revenues

Description		Effective August 1, 2022		Effective September 1, 2022
Test Year Adjusted Distribution Revenues	$	39,796,840		
Permanent Rate Increase [1]		6,321,881		
Distribution Revenues	$	46,118,721	$	46,118,721
Add: Step Adjustment (Illustrative)		-		1,554,966
Target Distribution Revenues	$	46,118,721	$	47,673,687

Notes:
(1) Reflects permanent rate increase of $6,091,477 plus $231,477 related to the reduction of indirect production and A&G costs recovered as a part of the Company's Cost of Gas Clause

Northern Utilities, Inc. - New Hampshire Division
Decoupling
Target Revenues by Class

Distribution Revenues	Residential		Commercial and Industrial						
August 1, 2022-July 31, 2023	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
Test Year Distribution Revenues	$ 493,626	$ 20,731,783	$ 6,745,829	$ 1,024,226	$ 5,235,691	$ 1,396,947	$ 1,545,114	$ 2,623,624	$ 39,796,840
Rate Increase	156,858	4,153,139	803,485	81,431	623,639	111,074	183,925	208,329	6,321,881
Distribution Revenues	$ 650,484	$ 24,884,923	$ 7,549,314	$ 1,105,657	$ 5,859,330	$ 1,508,021	$ 1,729,040	$ 2,831,954	$ 46,118,721
Add: Step Increase (Illustrative)	-	-	-	-	-	-	-	-	-
Target Distribution Revenues	$ 650,484	$ 24,884,923	$ 7,549,314	$ 1,105,657	$ 5,859,330	$ 1,508,021	$ 1,729,040	$ 2,831,954	$ 46,118,721

Distribution Revenues	Residential		Commercial and Industrial						
September 1, 2022-July 31, 2023	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
Distribution Revenues	$ 650,484	$ 24,884,923	$ 7,549,314	$ 1,105,657	$ 5,859,330	$ 1,508,021	$ 1,729,040	$ 2,831,954	$ 46,118,721
Add: Step Increase (Illustrative)	21,932	839,035	254,537	37,279	197,557	50,845	58,297	95,484	1,554,966
Target Distribution Revenues	$ 672,416	$ 25,723,957	$ 7,803,851	$ 1,142,936	$ 6,056,886	$ 1,558,867	$ 1,787,337	$ 2,927,437	$ 47,673,687

Northern Utilities, Inc. - New Hampshire Division
Decoupling
Target Revenue Per Customer (August 1, 2022 - July 31, 2023)

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial						
Target Distribution Revenues	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
August	$ 43,469	869,904	$ 440,087	$ 90,360	$ 224,198	$ 109,671	$ 81,872	$ 179,237	$ 2,038,797
September	45,061	1,065,619	471,242	89,712	266,617	110,685	90,199	193,243	2,332,378
October	49,036	1,544,043	546,135	89,697	386,028	117,578	121,777	197,663	3,051,958
November	56,938	2,380,112	676,041	92,963	571,508	129,681	162,326	285,141	4,354,712
December	67,596	3,410,170	841,505	99,163	784,836	145,866	205,766	313,238	5,868,140
January	70,787	3,822,380	907,302	101,082	864,510	150,812	232,479	273,823	6,423,175
February	65,398	3,461,729	848,677	98,465	785,679	143,803	212,555	303,245	5,919,552
March	61,346	3,013,885	773,827	94,858	686,417	139,369	194,882	281,262	5,245,846
April	53,002	2,015,950	617,331	86,058	466,208	121,141	149,170	279,727	3,788,586
May	49,588	1,435,099	527,417	86,742	347,432	118,302	109,412	177,511	2,851,503
June	45,129	1,022,468	463,646	87,704	257,466	112,031	87,286	175,188	2,250,918
July	43,134	843,564	436,103	88,852	218,430	109,081	81,314	172,675	1,993,154
12ME July	$ 650,484	$ 24,884,923	$7,549,314	$1,105,657	$5,859,330	$1,508,021	$1,729,040	$2,831,954	$ 46,118,721

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial					
Customers in Authorized Rate Design	R6	R5-R10	G40	G50	G41	G51	G42	G52
August	$ 1,277	$ 26,815	$ 5,234	$ 831	$ 704	$ 267	$ 31	$ 33
September	1,277	26,815	5,234	831	704	267	31	33
October	1,277	26,815	5,234	831	704	267	31	33
November	1,277	26,815	5,234	831	704	267	31	33
December	1,277	26,815	5,234	831	704	267	31	33
January	1,277	26,815	5,234	831	704	267	31	33
February	1,277	26,815	5,234	831	704	267	31	33
March	1,277	26,815	5,234	831	704	267	31	33
April	1,277	26,815	5,234	831	704	267	31	33
May	1,277	26,815	5,234	831	704	267	31	33
June	1,277	26,815	5,234	831	704	267	31	33
July	1,277	26,815	5,234	831	704	267	31	33

Effective August 1, 2022-July 31, 2023	Residential		Commercial and Industrial					
Monthly Revenue Per Customer	R6	R5-R10	G40	G50	G41	G51	G42	G52
August	$ 34.05	$ 32.44	$ 84.08	$ 108.68	$ 318.36	$ 411.52	$ 2,641.02	$ 5,431.42
September	35.29	39.74	90.03	107.90	378.59	415.33	2,909.65	5,855.83
October	38.41	57.58	104.34	107.88	548.15	441.19	3,928.30	5,989.80
November	44.60	88.76	129.16	111.81	811.53	486.61	5,236.34	8,640.65
December	52.95	127.17	160.77	119.26	1,114.46	547.34	6,637.61	9,492.05
January	55.45	142.55	173.34	121.57	1,227.59	565.90	7,499.33	8,297.66
February	51.22	129.10	162.14	118.42	1,115.65	539.60	6,856.63	9,189.26
March	48.05	112.40	147.84	114.09	974.70	522.96	6,286.51	8,523.10
April	41.51	75.18	117.94	103.50	662.01	454.56	4,811.93	8,476.58
May	38.84	53.52	100.76	104.32	493.35	443.91	3,529.42	5,379.12
June	35.35	38.13	88.58	105.48	365.60	420.38	2,815.68	5,308.73
July	33.79	31.46	83.32	106.86	310.17	409.31	2,623.05	5,232.57
Total	$ 509.50	$ 928.03	$ 1,442.27	$ 1,329.77	$ 8,320.15	$ 5,658.62	$55,775.47	$85,816.77

Northern Utilities New Hampshire
Target Revenue Per Customer (August 1, 2022 - July 31, 2023)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
1	R-5	Residential Heating	January	26,171	3,569,155	0	3,569,155	$ 3,736,488	$ 142.77
2			February	26,171	3,167,143	0	3,167,143	$ 3,381,069	$ 129.19
3		*Rates*	March	26,171	2,668,501	0	2,668,501	$ 2,940,220	$ 112.35
4		*Customer*	April	26,171	1,566,216	0	1,566,216	$ 1,965,690	$ 75.11
5		*$22.20*	May	26,171	0	926,189	926,189	$ 1,399,842	$ 53.49
6		*Per Therm*	June	26,171	0	471,753	471,753	$ 998,075	$ 38.14
7		*$0.8841*	July	26,171	0	274,716	274,716	$ 823,875	$ 31.48
8			August	26,171	0	303,731	303,731	$ 849,527	$ 32.46
9			September	26,171	0	519,219	519,219	$ 1,040,040	$ 39.74
10			October	26,171	0	1,047,855	1,047,855	$ 1,507,407	$ 57.60
11			November	26,171	1,975,568	0	1,975,568	$ 2,327,598	$ 88.94
12			December	26,171	3,115,886	0	3,115,886	$ 3,335,753	$ 127.46
13					16,062,468	3,543,464	19,605,931	$ 24,305,585	$ 928.72
14	R-10	Res. Heating, Low Income	January	644	80,989	0	80,989	$ 85,892	$ 133.44
15			February	644	75,070	0	75,070	$ 80,660	$ 125.31
16		*Rates*	March	644	67,158	0	67,158	$ 73,665	$ 114.44
17		*Customer*	April	644	40,685	0	40,685	$ 50,260	$ 78.08
18		*$22.20*	May	644	0	23,715	23,715	$ 35,257	$ 54.77
19		*Per Therm*	June	644	0	11,427	11,427	$ 24,393	$ 37.90
20		*$0.8841*	July	644	0	6,106	6,106	$ 19,688	$ 30.59
21			August	644	0	6,885	6,885	$ 20,377	$ 31.66
22			September	644	0	12,769	12,769	$ 25,579	$ 39.74
23			October	644	0	25,275	25,275	$ 36,636	$ 56.92
24			November	644	43,235	0	43,235	$ 52,514	$ 81.58
25			December	644	68,009	0	68,009	$ 74,417	$ 115.61
26					375,147	86,179	461,326	$ 579,338	$ 900.02
27	R-6	Residential Non-Heating	January	1,277	32,447	0	32,447	$ 70,787	$ 55.45
28			February	1,277	28,328	0	28,328	$ 65,398	$ 51.22
29		*Rates*	March	1,277	25,230	0	25,230	$ 61,346	$ 48.05
30		*Customer*	April	1,277	18,851	0	18,851	$ 53,002	$ 41.51
31		*$22.20*	May	1,277	0	16,241	16,241	$ 49,588	$ 38.84
32		*Per Therm*	June	1,277	0	12,833	12,833	$ 45,129	$ 35.35
33		*$1.3081*	July	1,277	0	11,308	11,308	$ 43,134	$ 33.79
34			August	1,277	0	11,564	11,564	$ 43,469	$ 34.05
35			September	1,277	0	12,781	12,781	$ 45,061	$ 35.29
36			October	1,277	0	15,819	15,819	$ 49,036	$ 38.41
37			November	1,277	21,860	0	21,860	$ 56,938	$ 44.60
38			December	1,277	30,008	0	30,008	$ 67,596	$ 52.95
39					156,724	80,545	237,269	$ 650,484	$ 509.50

Northern Utilities New Hampshire
Target Revenue Per Customer (August 1, 2022 - July 31, 2023)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
40	G-40/T-40	Low Annual, High Winter	January	5,234	2,105,842	0	2,105,842	$ 907,302	$ 173.34
41			February	5,234	1,853,148	0	1,853,148	$ 848,677	$ 162.14
42		*Rates*	March	5,234	1,530,519	0	1,530,519	$ 773,827	$ 147.84
43		*Customer*	April	5,234	855,965	0	855,965	$ 617,331	$ 117.94
44		*$80.00*	May	5,234	0	468,408	468,408	$ 527,417	$ 100.76
45		*Per Therm*	June	5,234	0	193,531	193,531	$ 463,646	$ 88.58
46		*$0.2320*	July	5,234	0	74,813	74,813	$ 436,103	$ 83.32
47			August	5,234	0	91,982	91,982	$ 440,087	$ 84.08
48			September	5,234	0	226,274	226,274	$ 471,242	$ 90.03
49			October	5,234	0	549,088	549,088	$ 546,135	$ 104.34
50			November	5,234	1,109,028	0	1,109,028	$ 676,041	$ 129.16
51			December	5,234	1,822,234	0	1,822,234	$ 841,505	$ 160.77
52					9,276,737	1,604,096	10,880,833	$ 7,549,314	$ 1,442.27
53	G-50/T-50	Low Annual, Low Winter	January	831	165,778	0	165,778	$ 101,082	$ 121.57
54			February	831	153,226	0	153,226	$ 98,465	$ 118.42
55		*Rates*	March	831	135,926	0	135,926	$ 94,858	$ 114.09
56		*Customer*	April	831	93,720	0	93,720	$ 86,058	$ 103.50
57		*$80.00*	May	831	0	97,002	97,002	$ 86,742	$ 104.32
58		*Per Therm*	June	831	0	101,613	101,613	$ 87,704	$ 105.48
59		*$0.2085*	July	831	0	107,123	107,123	$ 88,852	$ 106.86
60			August	831	0	114,352	114,352	$ 90,360	$ 108.68
61			September	831	0	111,245	111,245	$ 89,712	$ 107.90
62			October	831	0	111,176	111,176	$ 89,697	$ 107.88
63			November	831	126,839	0	126,839	$ 92,963	$ 111.81
64			December	831	156,573	0	156,573	$ 99,163	$ 119.26
65					832,063	642,511	1,474,573	$ 1,105,657	$ 1,329.77
66	G-41/T-41	Med. Annual, High Winter	January	704	2,573,095	0	2,573,095	$ 864,510	$ 1,227.59
67			February	704	2,285,810	0	2,285,810	$ 785,679	$ 1,115.65
68		*Rates*	March	704	1,924,069	0	1,924,069	$ 686,417	$ 974.70
69		*Customer*	April	704	1,121,559	0	1,121,559	$ 466,208	$ 662.01
70		*$225.00*	May	704	0	688,701	688,701	$ 347,432	$ 493.35
71		*Per Therm*	June	704	0	360,838	360,838	$ 257,466	$ 365.60
72		*$0.2744*	July	704	0	218,577	218,577	$ 218,430	$ 310.17
73			August	704	0	239,596	239,596	$ 224,198	$ 318.36
74			September	704	0	394,184	394,184	$ 266,617	$ 378.59
75			October	704	0	829,358	829,358	$ 386,028	$ 548.15
76			November	704	1,505,305	0	1,505,305	$ 571,508	$ 811.53
77			December	704	2,282,740	0	2,282,740	$ 784,836	$ 1,114.46
78					11,692,577	2,731,254	14,423,832	$ 5,859,330	$ 8,320.15

Northern Utilities New Hampshire
Target Revenue Per Customer (August 1, 2022 - July 31, 2023)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
79	G-51/T-51	Med. Annual, Low Winter	January	267	548,609	0	548,609	$ 150,812	$ 565.90
80			February	267	506,285	0	506,285	$ 143,803	$ 539.60
81		*Rates*	March	267	479,510	0	479,510	$ 139,369	$ 522.96
82		*Customer*	April	267	369,435	0	369,435	$ 121,141	$ 454.56
83		*$225.00*	May	267	0	352,292	352,292	$ 118,302	$ 443.91
84		*Per Therm*	June	267	0	314,422	314,422	$ 112,031	$ 420.38
85		*$0.1656*	July	267	0	296,610	296,610	$ 109,081	$ 409.31
86			August	267	0	300,172	300,172	$ 109,671	$ 411.52
87			September	267	0	306,298	306,298	$ 110,685	$ 415.33
88			October	267	0	347,918	347,918	$ 117,578	$ 441.19
89			November	267	421,008	0	421,008	$ 129,681	$ 486.61
90			December	267	518,741	0	518,741	$ 145,866	$ 547.34
91					2,843,588	1,917,712	4,761,300	$ 1,508,021	$ 5,658.62
92	G-42/T-42	High Annual, High Winter	January	31	915,167	0	915,167	$ 232,479	$ 7,499.33
93			February	31	819,517	0	819,517	$ 212,555	$ 6,856.63
94		*Rates*	March	31	734,670	0	734,670	$ 194,882	$ 6,286.51
95		*Customer*	April	31	515,218	0	515,218	$ 149,170	$ 4,811.93
96		*$1,350.00*	May	31	0	324,350	324,350	$ 109,412	$ 3,529.42
97		*Per Therm*	June	31	0	218,129	218,129	$ 87,286	$ 2,815.68
98		*$0.2083*	July	31	0	189,460	189,460	$ 81,314	$ 2,623.05
99			August	31	0	192,134	192,134	$ 81,872	$ 2,641.02
100			September	31	0	232,113	232,113	$ 90,199	$ 2,909.65
101			October	31	0	383,712	383,712	$ 121,777	$ 3,928.30
102			November	31	578,379	0	578,379	$ 162,326	$ 5,236.34
103			December	31	786,923	0	786,923	$ 205,766	$ 6,637.61
104					4,349,875	1,539,897	5,889,772	$ 1,729,040	$ 55,775.47
105	G-52/T-52	High Annual, Low Winter	January	33	1,332,981	0	1,332,981	$ 273,823	$ 8,297.66
106			February	33	1,504,043	0	1,504,043	$ 303,245	$ 9,189.26
107		*Rates*	March	33	1,376,235	0	1,376,235	$ 281,262	$ 8,523.10
108		*Customer*	April	33	1,342,269	41,018	1,383,288	$ 279,727	$ 8,476.58
109		*$1,350.00*	May	33	5,650	1,257,039	1,262,689	$ 177,511	$ 5,379.12
110		*Per Therm Summer*	June	33	12,462	1,223,757	1,236,219	$ 175,188	$ 5,308.73
111		*$0.1050*	July	33	0	1,220,236	1,220,236	$ 172,675	$ 5,232.57
112		*Per Therm Winter*	August	33	0	1,282,733	1,282,733	$ 179,237	$ 5,431.42
113		*$0.1720*	September	33	0	1,416,119	1,416,119	$ 193,243	$ 5,855.83
114			October	33	43,229	1,387,409	1,430,639	$ 197,663	$ 5,989.80
115			November	33	1,381,287	28,665	1,409,953	$ 285,141	$ 8,640.65
116			December	33	1,562,138	0	1,562,138	$ 313,238	$ 9,492.05
117					8,560,295	7,856,979	16,417,274	$ 2,831,954	$ 85,816.77
118		Total			54,149,473	20,002,636	74,152,109	$ 46,118,721	

Northern Utilities, Inc. - New Hampshire Division
Decoupling
Target Revenue Per Customer (September 1, 2022 - July 31, 2023)

Effective September 1, 2022-July 31, 2023	Residential		Commercial and Industrial						
Target Distribution Revenues	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
August (at August 1, 2022 Rates)	$ 43,469	869,904	$ 440,087	$ 90,360	$ 224,198	$ 109,671	$ 81,872	$ 179,237	$ 2,038,797
September	46,303	1,088,212	476,581	92,761	272,107	114,176	92,574	199,807	2,382,521
October	50,573	1,589,617	559,090	92,744	397,580	121,543	125,703	204,424	3,141,274
November	59,063	2,465,848	702,206	96,439	592,474	134,480	168,244	295,764	4,514,517
December	70,512	3,545,385	884,496	103,454	816,630	151,778	213,818	325,101	6,111,174
January	73,940	3,977,396	956,985	105,625	900,348	157,065	241,843	283,945	6,697,147
February	68,151	3,599,421	892,398	102,664	817,515	149,574	220,941	314,667	6,165,330
March	63,797	3,130,064	809,936	98,583	713,215	144,835	202,399	291,713	5,454,543
April	54,833	2,084,192	637,525	88,627	481,829	125,352	154,442	290,111	3,916,910
May	51,166	1,475,440	538,468	89,401	357,024	122,317	112,731	183,381	2,929,929
June	46,376	1,042,988	468,212	90,489	262,492	115,614	89,518	180,956	2,296,645
July	44,233	855,490	437,868	91,788	221,474	112,462	83,253	178,332	2,024,900
11ME July	$ 672,416	$ 25,723,957	$ 7,803,851	$ 1,142,936	$ 6,056,886	$ 1,558,867	$ 1,787,337	$ 2,927,437	$ 47,673,687

Effective September 1, 2022-July 31, 2023	Residential		Commercial and Industrial					
Customers in Authorized Rate Design	R6	R5-R10	G40	G50	G41	G51	G42	G52
September	$ 1,277	$ 26,815	$ 5,234	$ 831	$ 704	$ 267	$ 31	$ 33
October	1,277	26,815	5,234	831	704	267	31	33
November	1,277	26,815	5,234	831	704	267	31	33
December	1,277	26,815	5,234	831	704	267	31	33
January	1,277	26,815	5,234	831	704	267	31	33
February	1,277	26,815	5,234	831	704	267	31	33
March	1,277	26,815	5,234	831	704	267	31	33
April	1,277	26,815	5,234	831	704	267	31	33
May	1,277	26,815	5,234	831	704	267	31	33
June	1,277	26,815	5,234	831	704	267	31	33
July	1,277	26,815	5,234	831	704	267	31	33

Effective September 1, 2022-July 31, 2023	Residential		Commercial and Industrial					
Monthly Revenue Per Customer	R6	R5-R10	G40	G50	G41	G51	G42	G52
September	$ 36.27	$ 40.58	$ 91.05	$ 111.56	$ 386.39	$ 428.43	$ 2,986.26	$ 6,054.77
October	39.61	59.28	106.81	111.54	564.56	456.07	4,054.95	6,194.65
November	46.26	91.96	134.15	115.99	841.30	504.61	5,427.24	8,962.53
December	55.23	132.22	168.98	124.42	1,159.60	569.52	6,897.34	9,851.53
January	57.91	148.33	182.83	127.04	1,278.48	589.36	7,801.39	8,604.40
February	53.38	134.23	170.49	123.47	1,160.86	561.25	7,127.11	9,535.37
March	49.97	116.73	154.74	118.57	1,012.75	543.47	6,529.00	8,839.80
April	42.95	77.73	121.80	106.59	684.19	470.36	4,981.99	8,791.23
May	40.08	55.02	102.87	107.52	506.97	458.98	3,636.48	5,557.01
June	36.32	38.90	89.45	108.83	372.73	433.83	2,887.68	5,483.51
July	34.65	31.90	83.65	110.39	314.49	422.00	2,685.58	5,403.99
Total	$ 492.63	$ 926.88	$ 1,406.82	$ 1,265.93	$ 8,282.32	$ 5,437.88	$ 55,015.01	$ 83,278.80

Northern Utilities New Hampshire
Target Revenue Per Customer (September 1, 2022 - July 31, 2023)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
1	R-5	Residential Heating	January	26,171	3,569,155	0	3,569,155	$ 3,888,065	$ 148.56
2			February	26,171	3,167,143	0	3,167,143	$ 3,515,573	$ 134.33
3		*Rates*	March	26,171	2,668,501	0	2,668,501	$ 3,053,547	$ 116.68
4		*Customer*	April	26,171	1,566,216	0	1,566,216	$ 2,032,205	$ 77.65
5		*$22.20*	May	26,171	0	926,189	926,189	$ 1,439,176	$ 54.99
6		*Per Therm*	June	26,171	0	471,753	471,753	$ 1,018,110	$ 38.90
7		*$0.9266*	July	26,171	0	274,716	274,716	$ 835,542	$ 31.93
8			August	26,171	0	303,731	303,731	$ 862,426	$ 32.95
9			September	26,171	0	519,219	519,219	$ 1,062,090	$ 40.58
10			October	26,171	0	1,047,855	1,047,855	$ 1,551,908	$ 59.30
11			November	26,171	1,975,568	0	1,975,568	$ 2,411,497	$ 92.14
12			December	26,171	3,115,886	0	3,115,886	$ 3,468,080	$ 132.52
13					16,062,468	3,543,464	19,605,931	$ 25,138,219	$ 960.53
14	R-10	Res. Heating, Low Income	January	644	80,989	0	80,989	$ 89,331	$ 138.78
15			February	644	75,070	0	75,070	$ 83,848	$ 130.26
16		*Rates*	March	644	67,158	0	67,158	$ 76,517	$ 118.87
17		*Customer*	April	644	40,685	0	40,685	$ 51,988	$ 80.76
18		*$22.20*	May	644	0	23,715	23,715	$ 36,264	$ 56.34
19		*Per Therm*	June	644	0	11,427	11,427	$ 24,878	$ 38.65
20		*$0.9266*	July	644	0	6,106	6,106	$ 19,948	$ 30.99
21			August	644	0	6,885	6,885	$ 20,670	$ 32.11
22			September	644	0	12,769	12,769	$ 26,122	$ 40.58
23			October	644	0	25,275	25,275	$ 37,709	$ 58.58
24			November	644	43,235	0	43,235	$ 54,350	$ 84.43
25			December	644	68,009	0	68,009	$ 77,305	$ 120.10
26					375,147	86,179	461,326	$ 598,929	$ 930.46
27	R-6	Residential Non-Heating	January	1,277	32,447	0	32,447	$ 73,940	$ 57.91
28			February	1,277	28,328	0	28,328	$ 68,151	$ 53.38
29		*Rates*	March	1,277	25,230	0	25,230	$ 63,797	$ 49.97
30		*Customer*	April	1,277	18,851	0	18,851	$ 54,833	$ 42.95
31		*$22.20*	May	1,277	0	16,241	16,241	$ 51,166	$ 40.08
32		*Per Therm*	June	1,277	0	12,833	12,833	$ 46,376	$ 36.32
33		*$1.4053*	July	1,277	0	11,308	11,308	$ 44,233	$ 34.65
34			August	1,277	0	11,564	11,564	$ 44,593	$ 34.93
35			September	1,277	0	12,781	12,781	$ 46,303	$ 36.27
36			October	1,277	0	15,819	15,819	$ 50,573	$ 39.61
37			November	1,277	21,860	0	21,860	$ 59,063	$ 46.26
38			December	1,277	30,008	0	30,008	$ 70,512	$ 55.23
39					156,724	80,545	237,269	$ 673,540	$ 527.56

Northern Utilities New Hampshire
Target Revenue Per Customer (September 1, 2022 - July 31, 2023)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
40	G-40/T-40	Low Annual, High Winter	January	5,234	2,105,842	0	2,105,842	$ 956,985	$ 182.83
41			February	5,234	1,853,148	0	1,853,148	$ 892,398	$ 170.49
42		*Rates*	March	5,234	1,530,519	0	1,530,519	$ 809,936	$ 154.74
43		*Customer*	April	5,234	855,965	0	855,965	$ 637,525	$ 121.80
44		*$80.00*	May	5,234	0	468,408	468,408	$ 538,468	$ 102.87
45		*Per Therm*	June	5,234	0	193,531	193,531	$ 468,212	$ 89.45
46		*$0.2556*	July	5,234	0	74,813	74,813	$ 437,868	$ 83.65
47			August	5,234	0	91,982	91,982	$ 442,257	$ 84.49
48			September	5,234	0	226,274	226,274	$ 476,581	$ 91.05
49			October	5,234	0	549,088	549,088	$ 559,090	$ 106.81
50			November	5,234	1,109,028	0	1,109,028	$ 702,206	$ 134.15
51			December	5,234	1,822,234	0	1,822,234	$ 884,496	$ 168.98
52					9,276,737	1,604,096	10,880,833	$ 7,806,021	$ 1,491.31
53	G-50/T-50	Low Annual, Low Winter	January	831	165,778	0	165,778	$ 105,625	$ 127.04
54			February	831	153,226	0	153,226	$ 102,664	$ 123.47
55		*Rates*	March	831	135,926	0	135,926	$ 98,583	$ 118.57
56		*Customer*	April	831	93,720	0	93,720	$ 88,627	$ 106.59
57		*$80.00*	May	831	0	97,002	97,002	$ 89,401	$ 107.52
58		*Per Therm*	June	831	0	101,613	101,613	$ 90,489	$ 108.83
59		*$0.2359*	July	831	0	107,123	107,123	$ 91,788	$ 110.39
60			August	831	0	114,352	114,352	$ 93,494	$ 112.44
61			September	831	0	111,245	111,245	$ 92,761	$ 111.56
62			October	831	0	111,176	111,176	$ 92,744	$ 111.54
63			November	831	126,839	0	126,839	$ 96,439	$ 115.99
64			December	831	156,573	0	156,573	$ 103,454	$ 124.42
65					832,063	642,511	1,474,573	$ 1,146,070	$ 1,378.37
66	G-41/T-41	Med. Annual, High Winter	January	704	2,573,095	0	2,573,095	$ 900,348	$ 1,278.48
67			February	704	2,285,810	0	2,285,810	$ 817,515	$ 1,160.86
68		*Rates*	March	704	1,924,069	0	1,924,069	$ 713,215	$ 1,012.75
69		*Customer*	April	704	1,121,559	0	1,121,559	$ 481,829	$ 684.19
70		*$225.00*	May	704	0	688,701	688,701	$ 357,024	$ 506.97
71		*Per Therm*	June	704	0	360,838	360,838	$ 262,492	$ 372.73
72		*$0.2883*	July	704	0	218,577	218,577	$ 221,474	$ 314.49
73			August	704	0	239,596	239,596	$ 227,535	$ 323.10
74			September	704	0	394,184	394,184	$ 272,107	$ 386.39
75			October	704	0	829,358	829,358	$ 397,580	$ 564.56
76			November	704	1,505,305	0	1,505,305	$ 592,474	$ 841.30
77			December	704	2,282,740	0	2,282,740	$ 816,630	$ 1,159.60
78					11,692,577	2,731,254	14,423,832	$ 6,060,223	$ 8,605.42

Northern Utilities New Hampshire
Target Revenue Per Customer (September 1, 2022 - July 31, 2023)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
79	G-51/T-51	Med. Annual, Low Winter	January	267	548,609	0	548,609	$ 157,065	$ 589.36
80			February	267	506,285	0	506,285	$ 149,574	$ 561.25
81		*Rates*	March	267	479,510	0	479,510	$ 144,835	$ 543.47
82		*Customer*	April	267	369,435	0	369,435	$ 125,352	$ 470.36
83		*$225.00*	May	267	0	352,292	352,292	$ 122,317	$ 458.98
84		*Per Therm*	June	267	0	314,422	314,422	$ 115,614	$ 433.83
85		*$0.1770*	July	267	0	296,610	296,610	$ 112,462	$ 422.00
86			August	267	0	300,172	300,172	$ 113,092	$ 424.36
87			September	267	0	306,298	306,298	$ 114,176	$ 428.43
88			October	267	0	347,918	347,918	$ 121,543	$ 456.07
89			November	267	421,008	0	421,008	$ 134,480	$ 504.61
90			December	267	518,741	0	518,741	$ 151,778	$ 569.52
91					2,843,588	1,917,712	4,761,300	$ 1,562,288	$ 5,862.24
92	G-42/T-42	High Annual, High Winter	January	31	915,167	0	915,167	$ 241,843	$ 7,801.39
93			February	31	819,517	0	819,517	$ 220,941	$ 7,127.11
94		*Rates*	March	31	734,670	0	734,670	$ 202,399	$ 6,529.00
95		*Customer*	April	31	515,218	0	515,218	$ 154,442	$ 4,981.99
96		*$1,350.00*	May	31	0	324,350	324,350	$ 112,731	$ 3,636.48
97		*Per Therm*	June	31	0	218,129	218,129	$ 89,518	$ 2,887.68
98		*$0.2185*	July	31	0	189,460	189,460	$ 83,253	$ 2,685.58
99			August	31	0	192,134	192,134	$ 83,837	$ 2,704.43
100			September	31	0	232,113	232,113	$ 92,574	$ 2,986.26
101			October	31	0	383,712	383,712	$ 125,703	$ 4,054.95
102			November	31	578,379	0	578,379	$ 168,244	$ 5,427.24
103			December	31	786,923	0	786,923	$ 213,818	$ 6,897.34
104					4,349,875	1,539,897	5,889,772	$ 1,789,303	$ 57,719.44
105	G-52/T-52	High Annual, Low Winter	January	33	1,332,981	0	1,332,981	$ 283,945	$ 8,604.40
106			February	33	1,504,043	0	1,504,043	$ 314,667	$ 9,535.37
107		*Rates*	March	33	1,376,235	0	1,376,235	$ 291,713	$ 8,839.80
108		*Customer*	April	33	1,342,269	41,018	1,383,288	$ 290,111	$ 8,791.23
109		*$1,350.00*	May	33	5,650	1,257,039	1,262,689	$ 183,381	$ 5,557.01
110		*Per Therm Summer*	June	33	12,462	1,223,757	1,236,219	$ 180,956	$ 5,483.51
111		*$0.1096*	July	33	0	1,220,236	1,220,236	$ 178,332	$ 5,403.99
112		*Per Therm Winter*	August	33	0	1,282,733	1,282,733	$ 185,184	$ 5,611.62
113		*$0.1796*	September	33	0	1,416,119	1,416,119	$ 199,807	$ 6,054.77
114			October	33	43,229	1,387,409	1,430,639	$ 204,424	$ 6,194.65
115			November	33	1,381,287	28,665	1,409,953	$ 295,764	$ 8,962.53
116			December	33	1,562,138	0	1,562,138	$ 325,101	$ 9,851.53
117					8,560,295	7,856,979	16,417,274	$ 2,933,384	$ 88,890.42
118		Total			54,149,473	20,002,636	74,152,109	$ 47,707,977	

Northern Utilities, Inc. - New Hampshire Division
Decoupling
Target Revenue Per Customer (August 1, 2023 - July 31, 2024)

Effective August 1, 2023-July 31, 2024	Residential		Commercial and Industrial						
Target Distribution Revenues	R6	R5-R10	G40	G50	G41	G51	G42	G52	Total
August	$ 44,538	$ 882,891	$ 442,238	$ 93,251	$ 227,479	$ 112,876	$ 83,773	$ 184,835	$ 2,071,883
September	46,242	1,087,862	476,536	92,524	272,016	113,956	92,497	199,423	2,381,056
October	50,498	1,588,912	558,980	92,508	397,388	121,293	125,575	204,027	3,139,181
November	58,959	2,464,520	701,985	96,170	592,126	134,177	168,051	295,141	4,511,129
December	70,370	3,543,292	884,133	103,121	816,102	151,406	213,555	324,405	6,106,384
January	73,786	3,974,997	956,565	105,273	899,752	156,671	241,538	283,352	6,691,933
February	68,017	3,597,290	892,028	102,339	816,986	149,210	220,667	313,998	6,160,534
March	63,678	3,128,266	809,631	98,294	712,770	144,490	202,154	291,101	5,450,383
April	54,744	2,083,136	637,354	88,427	481,570	125,086	154,270	289,502	3,914,089
May	51,089	1,474,815	538,375	89,195	356,865	122,064	112,622	183,037	2,928,063
June	46,315	1,042,671	468,173	90,273	262,409	115,389	89,445	180,618	2,295,292
July	44,179	855,305	437,854	91,561	221,424	112,249	83,190	178,000	2,023,761
12ME July	$ 672,416	$25,723,957	$7,803,851	$1,142,936	$6,056,886	$1,558,867	$1,787,337	$2,927,437	$ 47,673,687

Effective August 1, 2023-July 31, 2024	Residential		Commercial and Industrial					
Customers in Authorized Rate Design	R6	R5-R10	G40	G50	G41	G51	G42	G52
August	$ 1,277	$ 26,815	$ 5,234	$ 831	$ 704	$ 267	$ 31	$ 33
September	1,277	26,815	5,234	831	704	267	31	33
October	1,277	26,815	5,234	831	704	267	31	33
November	1,277	26,815	5,234	831	704	267	31	33
December	1,277	26,815	5,234	831	704	267	31	33
January	1,277	26,815	5,234	831	704	267	31	33
February	1,277	26,815	5,234	831	704	267	31	33
March	1,277	26,815	5,234	831	704	267	31	33
April	1,277	26,815	5,234	831	704	267	31	33
May	1,277	26,815	5,234	831	704	267	31	33
June	1,277	26,815	5,234	831	704	267	31	33
July	1,277	26,815	5,234	831	704	267	31	33

Effective August 1, 2023-July 31, 2024	Residential		Commercial and Industrial					
Monthly Revenue Per Customer	R6	R5-R10	G40	G50	G41	G51	G42	G52
August	$ 34.89	$ 32.93	$ 84.49	$ 112.15	$ 323.02	$ 423.55	$ 2,702.37	$ 5,601.06
September	36.22	40.57	91.04	111.28	386.26	427.60	2,983.76	6,043.11
October	39.55	59.26	106.79	111.26	564.28	455.13	4,050.81	6,182.64
November	46.18	91.91	134.11	115.66	840.81	503.48	5,421.01	8,943.66
December	55.12	132.14	168.91	124.02	1,158.85	568.13	6,888.87	9,830.46
January	57.79	148.24	182.75	126.61	1,277.63	587.88	7,791.54	8,586.42
February	53.28	134.15	170.42	123.08	1,160.11	559.89	7,118.29	9,515.08
March	49.88	116.66	154.68	118.22	1,012.12	542.18	6,521.09	8,821.23
April	42.88	77.69	121.76	106.35	683.82	469.37	4,976.44	8,772.78
May	40.02	55.00	102.85	107.27	506.74	458.03	3,632.98	5,546.58
June	36.28	38.88	89.44	108.57	372.62	432.98	2,885.33	5,473.26
July	34.60	31.90	83.65	110.12	314.42	421.20	2,683.54	5,393.94
Total	$ 526.68	$ 959.32	$ 1,490.90	$ 1,374.60	$ 8,600.68	$ 5,849.41	$57,656.03	$88,710.22

Northern Utilities New Hampshire
Target Revenue Per Customer (August 1, 2023 - July 31, 2024)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
1	R-5	Residential Heating	January	26,171	3,569,155	0	3,569,155	$ 3,885,718	$ 148.47
2			February	26,171	3,167,143	0	3,167,143	$ 3,513,491	$ 134.25
3		*Rates*	March	26,171	2,668,501	0	2,668,501	$ 3,051,793	$ 116.61
4		*Customer*	April	26,171	1,566,216	0	1,566,216	$ 2,031,175	$ 77.61
5		*$22.20*	May	26,171	0	926,189	926,189	$ 1,438,567	$ 54.97
6		*Per Therm*	June	26,171	0	471,753	471,753	$ 1,017,800	$ 38.89
7		*$0.9259*	July	26,171	0	274,716	274,716	$ 835,361	$ 31.92
8			August	26,171	0	303,731	303,731	$ 862,226	$ 32.95
9			September	26,171	0	519,219	519,219	$ 1,061,749	$ 40.57
10			October	26,171	0	1,047,855	1,047,855	$ 1,551,219	$ 59.27
11			November	26,171	1,975,568	0	1,975,568	$ 2,410,199	$ 92.09
12			December	26,171	3,115,886	0	3,115,886	$ 3,466,032	$ 132.44
13					16,062,468	3,543,464	19,605,931	$ 25,125,331	$ 960.04
14	R-10	Res. Heating, Low Income	January	644	80,989	0	80,989	$ 89,278	$ 138.70
15			February	644	75,070	0	75,070	$ 83,798	$ 130.18
16		*Rates*	March	644	67,158	0	67,158	$ 76,473	$ 118.80
17		*Customer*	April	644	40,685	0	40,685	$ 51,961	$ 80.72
18		*$22.20*	May	644	0	23,715	23,715	$ 36,248	$ 56.31
19		*Per Therm*	June	644	0	11,427	11,427	$ 24,871	$ 38.64
20		*$0.9259*	July	644	0	6,106	6,106	$ 19,944	$ 30.98
21			August	644	0	6,885	6,885	$ 20,665	$ 32.10
22			September	644	0	12,769	12,769	$ 26,113	$ 40.57
23			October	644	0	25,275	25,275	$ 37,693	$ 58.56
24			November	644	43,235	0	43,235	$ 54,322	$ 84.39
25			December	644	68,009	0	68,009	$ 77,261	$ 120.03
26					375,147	86,179	461,326	$ 598,626	$ 929.99
27	R-6	Residential Non-Heating	January	1,277	32,447	0	32,447	$ 73,786	$ 57.79
28			February	1,277	28,328	0	28,328	$ 68,017	$ 53.28
29		*Rates*	March	1,277	25,230	0	25,230	$ 63,678	$ 49.88
30		*Customer*	April	1,277	18,851	0	18,851	$ 54,744	$ 42.88
31		*$22.20*	May	1,277	0	16,241	16,241	$ 51,089	$ 40.02
32		*Per Therm*	June	1,277	0	12,833	12,833	$ 46,315	$ 36.28
33		*$1.4005*	July	1,277	0	11,308	11,308	$ 44,179	$ 34.60
34			August	1,277	0	11,564	11,564	$ 44,538	$ 34.89
35			September	1,277	0	12,781	12,781	$ 46,242	$ 36.22
36			October	1,277	0	15,819	15,819	$ 50,498	$ 39.55
37			November	1,277	21,860	0	21,860	$ 58,959	$ 46.18
38			December	1,277	30,008	0	30,008	$ 70,370	$ 55.12
39					156,724	80,545	237,269	$ 672,416	$ 526.68

Northern Utilities New Hampshire
Target Revenue Per Customer (August 1, 2023 - July 31, 2024)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
40	G-40/T-40	Low Annual, High Winter	January	5,234	2,105,842	0	2,105,842	$ 956,565	$ 182.75
41			February	5,234	1,853,148	0	1,853,148	$ 892,028	$ 170.42
42		*Rates*	March	5,234	1,530,519	0	1,530,519	$ 809,631	$ 154.68
43		*Customer*	April	5,234	855,965	0	855,965	$ 637,354	$ 121.76
44		*$80.00*	May	5,234	0	468,408	468,408	$ 538,375	$ 102.85
45		*Per Therm*	June	5,234	0	193,531	193,531	$ 468,173	$ 89.44
46		*$0.2554*	July	5,234	0	74,813	74,813	$ 437,854	$ 83.65
47			August	5,234	0	91,982	91,982	$ 442,238	$ 84.49
48			September	5,234	0	226,274	226,274	$ 476,536	$ 91.04
49			October	5,234	0	549,088	549,088	$ 558,980	$ 106.79
50			November	5,234	1,109,028	0	1,109,028	$ 701,985	$ 134.11
51			December	5,234	1,822,234	0	1,822,234	$ 884,133	$ 168.91
52					9,276,737	1,604,096	10,880,833	$ 7,803,851	$ 1,490.90
53	G-50/T-50	Low Annual, Low Winter	January	831	165,778	0	165,778	$ 105,273	$ 126.61
54			February	831	153,226	0	153,226	$ 102,339	$ 123.08
55		*Rates*	March	831	135,926	0	135,926	$ 98,294	$ 118.22
56		*Customer*	April	831	93,720	0	93,720	$ 88,427	$ 106.35
57		*$80.00*	May	831	0	97,002	97,002	$ 89,195	$ 107.27
58		*Per Therm*	June	831	0	101,613	101,613	$ 90,273	$ 108.57
59		*$0.2338*	July	831	0	107,123	107,123	$ 91,561	$ 110.12
60			August	831	0	114,352	114,352	$ 93,251	$ 112.15
61			September	831	0	111,245	111,245	$ 92,524	$ 111.28
62			October	831	0	111,176	111,176	$ 92,508	$ 111.26
63			November	831	126,839	0	126,839	$ 96,170	$ 115.66
64			December	831	156,573	0	156,573	$ 103,121	$ 124.02
65					832,063	642,511	1,474,573	$ 1,142,936	$ 1,374.60
66	G-41/T-41	Med. Annual, High Winter	January	704	2,573,095	0	2,573,095	$ 899,752	$ 1,277.63
67			February	704	2,285,810	0	2,285,810	$ 816,986	$ 1,160.11
68		*Rates*	March	704	1,924,069	0	1,924,069	$ 712,770	$ 1,012.12
69		*Customer*	April	704	1,121,559	0	1,121,559	$ 481,570	$ 683.82
70		*$225.00*	May	704	0	688,701	688,701	$ 356,865	$ 506.74
71		*Per Therm*	June	704	0	360,838	360,838	$ 262,409	$ 372.62
72		*$0.2881*	July	704	0	218,577	218,577	$ 221,424	$ 314.42
73			August	704	0	239,596	239,596	$ 227,479	$ 323.02
74			September	704	0	394,184	394,184	$ 272,016	$ 386.26
75			October	704	0	829,358	829,358	$ 397,388	$ 564.28
76			November	704	1,505,305	0	1,505,305	$ 592,126	$ 840.81
77			December	704	2,282,740	0	2,282,740	$ 816,102	$ 1,158.85
78					11,692,577	2,731,254	14,423,832	$ 6,056,886	$ 8,600.68

Northern Utilities New Hampshire
Target Revenue Per Customer (August 1, 2023 - July 31, 2024)
Proposed Revenue by Calendar Month

[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]
				Billing Determinants				Calendar Month Revenue	
Line	Rate Class	Description	Month	Pro Forma Test Year Customers	Winter Therms	Summer Therms	Total Calendarized Therms	Total Calendarized Revenue	Calendarized Revenue Per Customer
79	G-51/T-51	Med. Annual, Low Winter	January	267	548,609	0	548,609	$ 156,671	$ 587.88
80			February	267	506,285	0	506,285	$ 149,210	$ 559.89
81		*Rates*	March	267	479,510	0	479,510	$ 144,490	$ 542.18
82		*Customer*	April	267	369,435	0	369,435	$ 125,086	$ 469.37
83		*$225.00*	May	267	0	352,292	352,292	$ 122,064	$ 458.03
84		*Per Therm*	June	267	0	314,422	314,422	$ 115,389	$ 432.98
85		*$0.1763*	July	267	0	296,610	296,610	$ 112,249	$ 421.20
86			August	267	0	300,172	300,172	$ 112,876	$ 423.55
87			September	267	0	306,298	306,298	$ 113,956	$ 427.60
88			October	267	0	347,918	347,918	$ 121,293	$ 455.13
89			November	267	421,008	0	421,008	$ 134,177	$ 503.48
90			December	267	518,741	0	518,741	$ 151,406	$ 568.13
91					2,843,588	1,917,712	4,761,300	$ 1,558,867	$ 5,849.41
92	G-42/T-42	High Annual, High Winter	January	31	915,167	0	915,167	$ 241,538	$ 7,791.54
93			February	31	819,517	0	819,517	$ 220,667	$ 7,118.29
94		*Rates*	March	31	734,670	0	734,670	$ 202,154	$ 6,521.09
95		*Customer*	April	31	515,218	0	515,218	$ 154,270	$ 4,976.44
96		*$1,350.00*	May	31	0	324,350	324,350	$ 112,622	$ 3,632.98
97		*Per Therm*	June	31	0	218,129	218,129	$ 89,445	$ 2,885.33
98		*$0.2182*	July	31	0	189,460	189,460	$ 83,190	$ 2,683.54
99			August	31	0	192,134	192,134	$ 83,773	$ 2,702.37
100			September	31	0	232,113	232,113	$ 92,497	$ 2,983.76
101			October	31	0	383,712	383,712	$ 125,575	$ 4,050.81
102			November	31	578,379	0	578,379	$ 168,051	$ 5,421.01
103			December	31	786,923	0	786,923	$ 213,555	$ 6,888.87
104					4,349,875	1,539,897	5,889,772	$ 1,787,337	$ 57,656.03
105	G-52/T-52	High Annual, Low Winter	January	33	1,332,981	0	1,332,981	$ 283,352	$ 8,586.42
106			February	33	1,504,043	0	1,504,043	$ 313,998	$ 9,515.08
107		*Rates*	March	33	1,376,235	0	1,376,235	$ 291,101	$ 8,821.23
108		*Customer*	April	33	1,342,269	41,018	1,383,288	$ 289,502	$ 8,772.78
109		*$1,350.00*	May	33	5,650	1,257,039	1,262,689	$ 183,037	$ 5,546.58
110		*Per Therm Summer*	June	33	12,462	1,223,757	1,236,219	$ 180,618	$ 5,473.26
111		*$0.1094*	July	33	0	1,220,236	1,220,236	$ 178,000	$ 5,393.94
112		*Per Therm Winter*	August	33	0	1,282,733	1,282,733	$ 184,835	$ 5,601.06
113		*$0.1791*	September	33	0	1,416,119	1,416,119	$ 199,423	$ 6,043.11
114			October	33	43,229	1,387,409	1,430,639	$ 204,027	$ 6,182.64
115			November	33	1,381,287	28,665	1,409,953	$ 295,141	$ 8,943.66
116			December	33	1,562,138	0	1,562,138	$ 324,405	$ 9,830.46
117					8,560,295	7,856,979	16,417,274	$ 2,927,437	$ 88,710.22
118		Total			54,149,473	20,002,636	74,152,109	$ 47,673,687	

DG 23-086

NORTHERN UTILITIES, INC.

DIRECT TESTIMONY

OF

TIMOTHY S. LYONS

EXHIBIT TSL-1

New Hampshire Public Utilities Commission

Docket No. DG 21-104

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is Timothy S. Lyons. I am a Partner with ScottMadden, Inc. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of Northern Utilities, Inc. ("Northern" or the "Company").

Q. Please describe your professional experience.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held a number of management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

Q. What is your educational background?

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business

Administration from Babson College. A summary of my professional and educational background, including a list of my testimony in prior proceedings, is included in Schedule TSL-1.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the Company's proposed revenue decoupling mechanism ("RDM") and associated tariff. The RDM addresses the basic misalignment between the structure of the Company's costs and its rates. Specifically, utility distribution costs are largely fixed and change very little in the short run with changes in usage levels. However, distribution rates have a significant variable, or usage-based, component that changes revenues (and cost recovery) with changes in usage levels. The RDM corrects for this misalignment by adjusting the Company's actual revenues to match its authorized revenues. RDMs have been approved in numerous jurisdictions, including New Hampshire, and are viewed in the industry as important to the development of Energy Efficiency ("EE") initiatives.

Q. How is the remaining portion of your testimony organized?

A. The remaining portion of my testimony is organized into the following sections.

- Section III provides an overview of revenue decoupling, including the Commission's guidance in the Gas and Electric Utilities Energy Efficiency Resource Standard proceeding ("EERS" proceeding).[1]
- Section IV describes the proposed RDM.
- Section V illustrates the calculation of the proposed RDM for the residential rate class.
- Section VI summarizes the benefits of the proposed RDM.

III. OVERVIEW OF REVENUE DECOUPLING

Q. What is revenue decoupling?

A. Revenue decoupling breaks or "decouples" the link between utility revenues and sales volumes, helping to ensure that a utility does not over- or under-recover its authorized revenue requirement. There are two basic forms of revenue decoupling:

- Partial or Limited Revenue Decoupling – this type addresses specific variances between actual and authorized revenues, such as the impact of weather or EE. The Company's current Lost Revenue Rate ("LRR") within the Local Delivery Adjustment Charge ("LDAC") is an example of partial or limited revenue decoupling.
- Full Revenue Decoupling – this type addresses the total variance between actual and authorized revenues. The Company's proposed RDM is an

[1] Docket DE 15-137

example of full revenue decoupling. Variances can be measured on the basis of total revenues, or revenues per customer ("RPC").

Q. Has the Commission approved a revenue decoupling mechanism for New Hampshire gas and electric utilities?

A. Yes. The Commission approved a lost revenue adjustment mechanism ("LRAM"), a partial or limited revenue decoupling mechanism, for all electric and gas utilities in the EERS proceeding,[2] noting:

> "…without the LRAM, or a change in the way rates are designed today, the utilities may lose revenue that the Commission has already determined in the utility's rate case is just and reasonable for them to recover. Consequently, we approve the LRAM as proposed."[3]

In the EERS proceeding, the Commission recognized the limitations of an LRAM and the role a full revenue decoupling mechanism can play in ensuring that the utility does not over- or under-recover its authorized revenue requirement. [4]

The Commission therefore required utilities to seek approval of a revenue decoupling mechanism, stating:

[2] Docket DE 15-137, Order No 25,932

[3] Id., p. 59

[4] Id., p. 59-60 ("[W]e are mindful that, with an LRAM, the utilities' revenues can increase above their authorized revenue requirements from increased sales, and, for that reason and others, some parties prefer decoupling. This is because decoupling provides a reconciliation to the last-approved revenue requirement.")

> "We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC) are required to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before."[5]

Following the EERS proceeding, the Commission approved full revenue decoupling mechanisms for Liberty Utilities (EnergyNorth Natural Gas) Corporation,[6] and Liberty Utilities (Granite State Electric) Corporation.[7]

The Company's proposed RDM is generally consistent with the revenue decoupling mechanism approved for Liberty Utilities (Granite State Electric) Corporation and the revenue decoupling mechanism recently filed by the Company's New Hampshire electric division (Unitil Energy Systems, Inc.)[8].

Q. Please provide an overview of the Company's proposed RDM.

A. The proposed RDM is a full revenue decoupling mechanism that reconciles monthly actual and authorized RPC by rate class. The proposed RDM is applicable to all rate classes. The Company proposes that the authorized RPC be adjusted

[5] Id., p. 60
[6] Docket DE 17-048, Order No. 26,122 at pp. 45-46 ("We applaud Liberty for proposing a decoupling mechanism to replace the LRAM.").
[7] Docket DE 19-064, Order No. 26,376 at pp. 9, 13 (approving a Settlement Agreement supporting the implementation of a decoupling mechanism).
[8] Docket DE 21-030.

DG 23-086

annually to reflect three estimated annual step increases on August 1, 2022 of $3.1 million; August 1, 2023 of $3.1 million; and August 1, 2024 of $3.2 million associated with 2021, 2022 and 2023 capital investments.

The proposed RDM process will consist of two steps:

In the first step, the Company will record monthly variances between actual and authorized RPC for each rate class. The monthly variances are then aggregated over the twelve-month period August through July (the “Measurement Period”). The monthly variances are recorded in a deferred account with carrying costs accrued at the Prime rate.[9] The aggregate variances and carrying costs form the basis for the revenue decoupling adjustment (“RDA”) and the calculation of RDM adjustment factor (“RDAF”) (surcharge or credit). For example, revenue surpluses (actual RPC is greater than authorized RPC) during the Measurement Period will result in a credit or refund for the customers. Conversely, revenue shortfalls (i.e., actual RPC is less than authorized RPC) during the Measurement Period will result in a surcharge to the customers.

In the second step, the Company will file with the Commission the applicable RDAF 45 days in advance of the effective date of November 1. The filing will include an allocation of the RDA, including prior period reconciliation and deferrals as a result of a cap, to each rate class, and calculation of the RDAF.

[9] Interest shall be calculated at the prime rate, with said prime rate to be fixed on a quarterly basis and to be established as reported in the Wall Street Journal on the first business day of the month preceding the calendar quarter. If more than one interest rate is reported, the average of the reported rates shall be used.

The RDA is allocated to each rate class based on the authorized revenues of each rate class in the most recent rate case, including step adjustments.

The RDAF is calculated as a dollar per therm charge or credit based on the RDA allocated to each rate class divided by the projected therm sales for each rate class over the prospective twelve-month period November through October ("RDM Adjustment Period"). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period.

The tariff for the Company's proposed RDM is included in Schedule TSL-2. Upon implementation of its first RDAF, the Company will incorporate the supporting RDAF calculation in its RDAC tariff.

Q. What are the primary benefits of the Company's proposed RDM?

A. There are three primary benefits of the Company's proposed RDM:

1. It corrects the basic misalignment between utility rates and costs;
2. It supports achievement of certain policy objectives, such as EE initiatives; and
3. It helps stabilize utility cost recovery as well as customer bills.

Q. Please discuss the basic misalignment between utility rates and costs.

A. Gas utilities incur three types of costs in providing natural gas service to customers:

- <u>Customer costs</u> – including meter, billing and a portion of distribution costs that generally vary by the number of customers;

- <u>Demand-related costs</u> – including transmission and distribution costs that generally vary by demand; and
- <u>Commodity-related costs</u> – including variable Operating and Maintenance expenses that generally vary by therm sales or natural gas consumed.

Utility revenue requirements and rates are designed to recover all of these costs. However, especially for residential customers, a significant portion of the revenue requirements are recovered on the basis of consumption charges reflecting usage at the time rates are established (i.e., rates are set based on an assumed level of usage). Thus, to the extent that actual usage is significantly lower than the assumed level of usage in rates, the utility rates no longer recover the authorized revenue requirements. Conversely, to the extent that actual usage is significantly higher than the assumed level of usage in rates, then utility rates recover more than the authorized revenue requirements.

Revenue decoupling corrects for this misalignment by adjusting revenues to match the authorized revenue requirements.

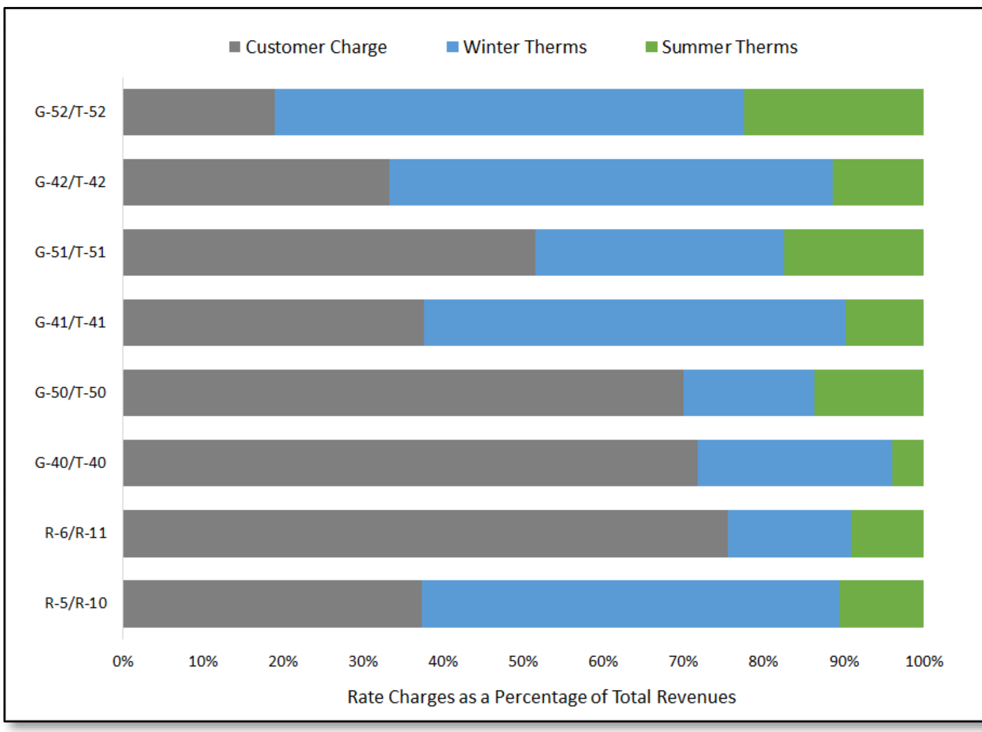
Q. Has the Commission recognized this misalignment between utility rates and costs?

A. Yes. In the EERS proceeding, the Commission noted this misalignment in the context of energy savings due to EE programs. The Commission stated: "With increased energy savings comes decreased utility revenues due to standard rate design, which recovers costs through a variable, or consumption-based, rate."[10]

Q. Do the Company's current rates exhibit this misalignment between utility costs and rates?

A. Yes. The portion of the Company's charges that are based on consumption (therm sales) is significant, as shown in Figure 1.

Figure 1: Consumption Revenues as Percentage of Total Revenues[11]



The Figure shows that a significant portion of the Company's residential and commercial distribution revenues are recovered through usage (therms). For

[10] Docket DE 15-137, Order No 25,932, p. 59
[11] Source: Settlement Agreement in Docket DG 17-070, Exhibit 2.

example, the Figure shows that approximately 60 percent of Residential Heating (R-5 and R-10 rate classes) revenues are recovered through consumption charges.

Q. Please discuss how revenue decoupling supports certain policy objectives.

A. The proposed RDM supports certain policy objectives, such as EE initiatives. Recovery of fixed costs through variable charges creates an inherent financial disincentive for utilities to promote initiatives that reduce customer consumption and has been referenced as a "primary barrier to aggressive utility investment in energy efficiency."[12]

The RDM removes this financial disincentive, facilitating policies aimed to encourage EE initiatives. The Commission has noted: "Decoupling . . . was designed to sever the link between sales and revenues to remove [a utility's] disincentive to promote energy conservation that is inherent in traditional ratemaking."[13]

Q. Has the utility industry recognized the benefits of RDM in achieving policy objectives?

A. Yes. Revenue decoupling is recognized by the utility industry as an essential tool in promoting EE initiatives. An ACEEE report states: "For energy efficiency to

[12] National Action Plan for Energy Efficiency (2007): Aligning Utility Incentives with Investment in Energy Efficiency, at p. ES-3
[13] Docket DG 19-145, Order No 26,306 at p. 7.

flourish, the use of decoupling needs to be expanded so that utilities can recover their fixed costs even if sales decline."[14] Moreover, the benefits of revenue decoupling are recognized in regulatory jurisdictions throughout the U.S. Full revenue decoupling is currently in effect in 22 jurisdictions, including New Hampshire. In New England, full revenue decoupling is currently in effect for 20 of 26 electric and gas utilities, as shown in Schedule TSL-3.[15]

IV. NORTHERN'S PROPOSED REVENUE DECOUPLING MECHANISM

Q. What are the key features of the Company's proposed RDM?

A. There are seven key features of the Company's proposed RDM discussed in this section, including:

1. Type of RDM
2. Revenue Adjustments
3. Applicable Rate Classes
4. Deferred Account
5. Class Allocation
6. Factor Calculation
7. Adjustment Cap

[14] ACEEE The Future of the Utility Industry and the Role of Energy Efficiency (June 2014), at p. viii
[15] S&P Global Market Intelligence. Data as of April 12, 2021.

1. <u>Type of RDM</u>

Q. What type of RDM is the Company proposing?

A. The Company's proposed RDM is a full revenue decoupling mechanism. The proposed RDM reconciles monthly variances between actual and authorized RPC for each rate class. As discussed earlier, full revenue decoupling better accomplishes the Commission's policy objective to severe the link between volumes and revenues, providing a greater incentive to pursue energy efficiency, as compared to partial or limited revenue decoupling.

Q. What is the primary benefit of the proposed RPC approach?

A. The primary benefit of the proposed RPC approach is the recognition of new customer revenues. The Company expects to add new customers and incur incremental costs to serve new customers during the term of the RDM. The incremental costs are related to providing new customers with access to the distribution system and meeting their demand requirements. Under the RPC approach, the Company retains the RPC associated with serving new customers that is used to offset the costs associated with new customers.

By comparison, under a total revenue approach, the Company does not retain incremental revenues to offset the incremental costs, creating an adverse financial impact when adding new customers.

2. Revenue Adjustments

Q. Is the Company proposing annual adjustments to the authorized RPC?

A. Yes. The Company proposes that the authorized RPC be adjusted annually to reflect three estimated step increases on August 1, 2022 of $3.1 million, August 1, 2023 of $3.1 million, and August 1, 2024 of $3.2 million associated with the 2021, 2022 and 2023 capital investments, as discussed in the testimony of Company witnesses Messrs. Christopher Goulding and Daniel Nawazelski.

Schedule TSL-4 shows derivation of the authorized RPC for the first step increase on August 1, 2022. Specifically, the Schedule shows the authorized RPC is based on the authorized revenues divided by the number of customers included in the authorized rate design. The authorized revenues are based on the target distribution revenues plus the step increase.

For example, the authorized RPC in August 2022 for the residential heating class of $40.49 is based on the authorized revenues of $51,687 divided by the number of customers included in the authorized rate design of 1,277. The authorized revenues of $51,687 are based on the target distribution revenues of $48,504 plus the 2022 step increase of $3,183.

Q. Why is the Company proposing the annual adjustments?

A. The Company proposes the annual adjustments to align the authorized revenue requirements with the authorized RPC. In other words, as the Company's authorized revenue requirement increases as a result of the step increases, the Company's authorized RPC should similarly increase.

3. <u>Applicable Rate Classes</u>

Q. What rate classes would the proposed RDM apply to?

A. The Company proposes that the RDM be applicable to the Company's Residential Heating and Non-Heating Service (Schedules R-5 and R10 combined, and R-6), Commercial and Industrial Service (Schedules G-40, G-50, G-41, G-42, G-51, and G-52) customer classes. The revenues associated with special contracts will not be included as part of the RDM.

4. <u>Deferred Account</u>

Q. Is the Company proposing to establish a deferred account to record variances between actual and authorized RDM?

A. Yes. The Company proposes to establish a deferred account to record monthly variances between actual and authorized RPC. The monthly variances will be calculated by rate class and then recorded in a deferred account with carrying costs at the Prime rate.

The aggregate monthly variances and carrying costs form the basis for the RDA and the calculation of RDAF (surcharge or credit). For example, revenue surpluses (i.e., actual RPC greater than authorized RPC) during the Measurement Period will result in a credit or refund to customers, while revenue shortfalls (i.e.,

DG 23-086

actual RPC less than authorized RPC) during the Measurement Period will result in a surcharge to customers.

Q. What is the proposed process to establish the RDAF?

A. The Company proposes to file with the Commission the applicable RDAF 45 days before the effective date of November 1. The filing will include an allocation of the RDA to each rate class, and the calculation of the RDAF. The RDA is allocated to each rate class based on the authorized revenues of each rate class in the most recent rate case, including step adjustments. The RDAF will be calculated as a dollar per therm charge or credit based on the RDA allocated to each rate class divided by the projected therm sales for each rate class over the RDM Adjustment Period (prospective 12-month period November through October). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period. The RDM process will follow the schedule below.

Dates	Activity
August 1 through July 31	Measure and record monthly in a deferred account the revenue variances between actual and authorized RPC
On or about September 17 (45 days before November 1)	File with the Commission the RDAF based on the aggregate monthly revenue variances and monthly carrying costs on the deferred account balances
November 1 through October 31	Apply the RDAF to customer bills

5. <u>Class Allocation</u>

DG 23-086

Q. How will the revenue decoupling adjustment be allocated to each rate class?

A. The RDA will be allocated to each rate class based on the proportion of authorized revenues in the most recent rate case, including step adjustments.

6. <u>Factor Calculation</u>

Q. How will the RDAF be calculated?

A. The RDAF will be calculated on a dollar per therm basis for each rate class based on the RDA allocated to each rate class divided by the projected class therm sales for the RDM Adjustment Period (November through October). The RDAF will be applied to customer bills during the RDM Adjustment Period.

7. <u>Adjustment Cap</u>

Q. Is the Company proposing any adjustment cap?

A. Northern proposes to limit the RDA to two- and one-half percent (2.5%) of total revenues from delivered sales for the most recent twelve-month period, August through July, with revenue for externally supplied customers being adjusted by imputing the Company's cost of gas charges for that period. To help mitigate customer bill impacts, the cap would be applicable only to revenue shortfalls. Under-recovered revenues in excess of the adjustment cap would be held in the deferred account with carrying costs and included in the next RDAF filing.

V. ILLUSTRATIVE CALCULATION OF DECOUPLING MECHANISM

Q. How will the Company implement the proposed RDM?

A. As explained above, the proposed RDM process consists of two steps:

In the first step, the Company calculates the monthly variances between actual and authorized RPC for each rate class. The variances are calculated monthly and then aggregated over the twelve-month period August through July (the Measurement Period). The monthly variances are recorded in a deferred account with carrying costs accrued at the Prime rate. The aggregate variances and carrying costs form the basis for the RDA and the calculation of RDAF (surcharge or credit). For example, if the Company experiences a revenue surplus (actual revenues are greater than authorized revenues) during the Measurement Period, the RDM will result in a credit or refund to customers. Conversely, if the Company experiences a revenue shortfall (actual revenues are less than authorized revenues) during the Measurement Period, the RDM will result in a surcharge for customers.

In the second step, the Company files with the Commission the applicable RDAF 45 days before the effective date of November 1. The filing will include an allocation of the RDA to each rate class, and calculation of the RDAF. The RDA is allocated to each rate classes based on the authorized revenues of each rate class in the most recent rate case, including step adjustments. The RDAF will be calculated as a dollar per therm charge or credit based on the RDA allocated to each rate class divided by the projected therm sales for each rate class over the RDM Adjustment

DG 23-086

Period (twelve-month period November through October). The RDAF will be charged or credited to customer bills during the RDM Adjustment Period.

Q. Please illustrate the first step.

A. In the first step, the Company will calculate monthly variances between actual and authorized RPC for each rate class, as illustrated for the residential rate class in Figure 2 (below).

Figure 2: Monthly Residential Heating Revenue Variance Calculation (Illustrative)[16]

Illustrative Calculation	Actual Residential Heating			Authorized Residential Heating			Variance Over / (Under)	
Variance Over / (Under)	Revenues	Customers	RPC	Revenues	Customers	RPC	RPC	Revenues
August	$ 1,081,951	27,217	$ 39.75	$ 1,076,569	26,815	$ 40.15	$ (0.40)	$ (10,766)
September	1,283,256	27,217	47.15	1,276,871	26,815	47.62	(0.47)	(12,769)
October	1,775,342	27,217	65.23	1,766,509	26,815	65.88	(0.65)	(17,665)
November	2,635,287	27,217	96.82	2,622,176	26,815	97.79	(0.96)	(26,222)
December	3,694,761	27,217	135.75	3,676,379	26,815	137.10	(1.35)	(36,764)
January	4,118,742	27,217	151.33	4,098,251	26,815	152.84	(1.51)	(40,983)
February	3,747,792	27,217	137.70	3,729,146	26,815	139.07	(1.37)	(37,291)
March	3,287,159	27,217	120.78	3,270,805	26,815	121.98	(1.20)	(32,708)
April	2,260,725	27,217	83.06	2,249,478	26,815	83.89	(0.83)	(22,495)
May	1,663,286	27,217	61.11	1,655,011	26,815	61.72	(0.61)	(16,550)
June	1,238,872	27,217	45.52	1,232,709	26,815	45.97	(0.45)	(12,327)
July	1,054,859	27,217	38.76	1,049,611	26,815	39.14	(0.39)	(10,496)
12ME July	$ 27,842,031	326,604		$ 27,703,514	321,778			$ (277,035)

The Figure shows a four-phase process for each month assuming a 1.00 percent reduction in average revenue per customer for the residential sector. In the first phase, the Company calculates the authorized RPC per month by dividing the authorized monthly revenues by authorized monthly number of customers. In the second phase, the Company calculates the actual monthly RPC by dividing the actual revenues by the actual number of customers. In the third phase, the Company calculates the monthly variances between the actual and authorized RPC. In the

[16] The illustrative calculation assumes a 1.00 percent reduction in revenue per customer each month

final phase, the Company calculates the monthly revenue variance by multiplying the RPC variance with the actual number of customers.

The monthly revenue variances will be recorded in a deferred account with carrying costs accrued through the year at Prime rate, as illustrated for the residential rate class in Figure 3 (below).

Figure 3: Deferred Account Balance (Illustrative)[17]

Illustrative Deferred Account Balance	Deferred Account Starting Balance	Revenue Variance	Carrying Costs Rate	Carrying Costs	Deferred Account Ending Balance
August	$ -	$ (10,766)	0.27%	$ (15)	$ (10,780)
September	(10,780)	$ (12,769)	0.27%	(46)	$ (23,595)
October	(23,595)	$ (17,665)	0.27%	(88)	$ (41,348)
November	(41,348)	$ (26,222)	0.27%	(147)	$ (67,718)
December	(67,718)	$ (36,764)	0.27%	(233)	$ (104,715)
January	(104,715)	$ (40,983)	0.27%	(339)	$ (146,036)
February	(146,036)	$ (37,291)	0.27%	(446)	$ (183,774)
March	(183,774)	$ (32,708)	0.27%	(542)	$ (217,024)
April	(217,024)	$ (22,495)	0.27%	(618)	$ (240,137)
May	(240,137)	$ (16,550)	0.27%	(673)	$ (257,360)
June	(257,360)	$ (12,327)	0.27%	(714)	$ (270,400)
July	(270,400)	$ (10,496)	0.27%	(747)	$ (281,643)
August	(281,643)		0.27%	(763)	$ (282,406)
September	(282,406)		0.27%	(765)	$ (283,171)
October	(283,171)		0.27%	(767)	$ (283,938)
Total		$ (277,035)		$ (6,903)	$ (283,938)

The Figure shows that carrying costs of $6,903 will be accumulated through the year at the assumed Prime Rate. The aggregate monthly variances and carrying costs form the basis for the RDA and the calculation of RDAF surcharge or credit depending on the revenue variances.[18]

Q. Please discuss the second step in calculating the RDM adjustment.

[17] The illustrative calculation assumes a Prime Rate of 3.25 percent, or 0.2708 percent monthly
[18] The illustrative calculation shows RDA based on 12 months' ending July balance. However, the Company's proposed RDA filed will also include estimated carrying costs through October 31.

A. In the second step, the Company will file the applicable RDAF based on the RDA for the Measurement Period. The filing will include allocation of the RDA to rate classes, and calculation of the RDAF.

The RDA will be allocated to each rate class based on each class's authorized revenues, including step adjustments, as shown in Figure 4 (below).

Figure 4: Decoupling Adjustment Allocation (Illustrative)[19]

Illustrative Revenue Decoupling Adjustment	Authorized Revenues ($)	Authorized Revenues (%)	Allocated RDA ($)
Residential Non-Heating (R-6)	$ 737,886	1.45%	$ (4,112)
Residential Heating (R-5/R-10)	27,702,514	54.37%	(154,385)
C&I Low Annual, High Winter (G-40)	8,274,293	16.24%	(46,112)
C&I Low Annual, Low Winter (G-50)	1,201,344	2.36%	(6,695)
C&I Medium Annual, High Winter (G-41)	6,421,989	12.60%	(35,790)
C&I Medium Annual, Low Winter (G-51)	1,638,520	3.22%	(9,131)
C&I High Annual, High Winter (G-42)	1,895,204	3.72%	(10,562)
C&I High Annual, Low Winter (G-52)	3,077,325	6.04%	(17,150)
Total	$ 50,949,076	100.00%	$ (283,938)

The Figure shows that the Residential Heating class revenues are 54.37 percent of total Company revenues. Accordingly, the deferred account balance allocated to the Residential Heating class is $154,385.

The allocated RDA forms the basis for the calculation of RDAF for each rate class, as shown in Figure 5 (below).

[19] The RDA will be allocated to each rate class based on each class's authorized revenues. For illustrative purpose, Figure 4 currently shows the Company's proposed revenues plus 2022 step increase in the 'Authorized Revenues ($)' column. The illustrative deferred account balance assumes that only the Residential class experienced a revenue change.

Figure 5: Calculation of RDAF (Illustrative)

Illustrative Revenue Decoupling Adjustment	Charge/ (Refund) ($)	Adjusted Test Year Sales	Charge/ (Refund) ($/therm)
Residential Non-Heating (R-6)	$ 4,112	237,269	$ 0.0173
Residential Heating (R-5/R-10)	154,385	20,067,257	0.0077
C&I Low Annual, High Winter (G-40)	46,112	10,880,833	0.0042
C&I Low Annual, Low Winter (G-50)	6,695	1,474,573	0.0045
C&I Medium Annual, High Winter (G-41)	35,790	14,423,832	0.0025
C&I Medium Annual, Low Winter (G-51)	9,131	4,761,300	0.0019
C&I High Annual, High Winter (G-42)	10,562	5,889,772	0.0018
C&I High Annual, Low Winter (G-52)	17,150	16,417,274	0.0010
Total	$ 283,938	74,152,109	

The Figure shows that the RDAF for the Residential Heating class will be $0.0077 per therm. The adjustment factor would be implemented on customer bills during the November through October RDM Adjustment Period.

Q. Please describe how the RDAF will appear on customer bills.

A. For billing purposes, the Company plans to add the RDAF to the Distribution Charge component.

Q. Is the proposed RDM subject to reconciliation?

A. Yes. As described in Section 7.0 of the proposed tariff, the RDM is subject to reconciliation. Specifically, the actual revenues received by the Company through application of the RDAF to customer bills is reconciled to the RDM adjustment amount.

Q. Does this conclude your direct testimony?

DG 23-086

A. Yes, it does.

Northern Utilities, Inc.
New Hampshire Division
Revenue Decoupling Analysis

DG 23-086
Attachment 3
Page 1 of 1

	APPROVED RPC'S								
	Residential		Commercial and Industrial						
	R6	R5-R10	G40	G50	G41	G51	G42	G52	
August 2022	1,277	26,815	5,234	831	704	267	31	33	
September 2022	1,277	26,815	5,234	831	704	267	31	33	
October 2022	1,277	26,815	5,234	831	704	267	31	33	
November 2022	1,277	26,815	5,234	831	704	267	31	33	
December 2022	1,277	26,815	5,234	831	704	267	31	33	
January 2023	1,277	26,815	5,234	831	704	267	31	33	
February 2023	1,277	26,815	5,234	831	704	267	31	33	
March 2023	1,277	26,815	5,234	831	704	267	31	33	
April 2023	1,277	26,815	5,234	831	704	267	31	33	
May 2023	1,277	26,815	5,234	831	704	267	31	33	
June 2023	1,277	26,815	5,234	831	704	267	31	33	
July 2023	1,277	26,815	5,234	831	704	267	31	33	
August 2022	$ 34.05	$ 32.44	$ 84.08	$ 108.68	$ 318.36	$ 411.52	$ 2,641.02	$ 5,431.42	
September 2022	36.27	40.58	91.05	111.56	386.39	428.43	2,986.26	6,054.77	
October 2022	39.61	59.28	106.81	111.54	564.56	456.07	4,054.95	6,194.65	
November 2022	46.26	91.96	134.15	115.99	841.30	504.61	5,427.24	8,962.53	
December 2022	55.23	132.22	168.98	124.42	1,159.60	569.52	6,897.34	9,851.53	
January 2023	57.91	148.33	182.83	127.04	1,278.48	589.36	7,801.39	8,604.40	
February 2023	53.38	134.23	170.49	123.47	1,160.86	561.25	7,127.11	9,535.37	
March 2023	49.97	116.73	154.74	118.57	1,012.75	543.47	6,529.00	8,839.80	
April 2023	42.95	77.73	121.80	106.59	684.19	470.36	4,981.99	8,791.23	
May 2023	40.08	55.02	102.87	107.52	506.97	458.98	3,636.48	5,557.01	
June 2023	36.32	38.90	89.45	108.83	372.73	433.83	2,887.68	5,483.51	
July 2023	34.65	31.90	83.65	110.39	314.49	422.00	2,685.58	5,403.99	
Total Annual RPC	**$ 526.68**	**$ 959.32**	**$ 1,490.90**	**$ 1,374.60**	**$ 8,600.68**	**$ 5,849.41**	**$ 57,656.03**	**$ 88,710.22**	
August 2022	$ 43,469	$ 869,904	$ 440,087	$ 90,360	$ 224,198	$ 109,671	$ 81,872	$ 179,237	
September 2022	46,303	1,088,212	476,581	92,761	272,107	114,176	92,574	199,807	
October 2022	50,573	1,589,617	559,090	92,744	397,580	121,543	125,703	204,424	
November 2022	59,063	2,465,848	702,206	96,439	592,474	134,480	168,244	295,764	
December 2022	70,512	3,545,385	884,496	103,454	816,630	151,778	213,818	325,101	
January 2023	73,940	3,977,396	956,985	105,625	900,348	157,065	241,843	283,945	
February 2023	68,151	3,599,421	892,398	102,664	817,515	149,574	220,941	314,667	
March 2023	63,797	3,130,064	809,936	98,583	713,215	144,835	202,399	291,713	
April 2023	54,833	2,084,192	637,525	88,627	481,829	125,352	154,442	290,111	
May 2023	51,166	1,475,440	538,468	89,401	357,024	122,317	112,731	183,381	
June 2023	46,376	1,042,988	468,212	90,489	262,492	115,614	89,518	180,956	
July 2023	44,233	855,490	437,868	91,788	221,474	112,462	83,253	178,332	
Total Revenue	**$ 672,416**	**$ 25,723,957**	**$ 7,803,851**	**$ 1,142,936**	**$ 6,056,886**	**$ 1,558,867**	**$ 1,787,337**	**$ 2,927,437**	**$ 47,673,687**

	ACTUALS								
	Residential		Commercial and Industrial						
	R6	R5-R10	G40	G50	G41	G51	G42	G52	
August 2022	1,320	27,563	4,906	837	671	267	30	34	
September 2022	1,335	27,516	5,047	856	673	270	30	34	
October 2022	1,325	27,600	5,089	836	691	278	30	34	
November 2022	1,278	27,755	5,224	822	690	279	30	34	
December 2022	1,251	27,903	5,285	817	690	280	30	33	
January 2023	1,227	28,030	5,337	809	695	278	29	36	
February 2023	1,245	28,033	5,341	805	698	277	29	36	
March 2023	1,196	28,138	5,356	811	701	278	29	36	
April 2023	1,202	28,091	5,358	811	702	278	29	36	
May 2023	1,227	28,154	5,197	819	699	278	29	37	
June 2023	1,241	27,971	5,207	834	702	279	29	37	
July 2023	1,257	27,997	5,167	839	693	279	29	37	
Average Customers	**1,259**	**27,896**	**5,210**	**825**	**692**	**277**	**29**	**35**	
Change from Approved	**(18)**	**1,081**	**(25)**	**(7)**	**(12)**	**10**	**(2)**	**2**	
August 2022	$ 34.05	$ 32.44	$ 84.08	$ 108.68	$ 318.36	$ 411.52	$ 2,641.02	$ 5,431.42	
September 2022	36.27	40.58	91.05	111.56	386.39	428.43	2,986.26	6,054.77	
October 2022	39.61	59.28	106.81	111.54	564.56	456.07	4,054.95	6,194.65	
November 2022	46.26	91.96	134.15	115.99	841.30	504.61	5,427.24	8,962.53	
December 2022	55.23	132.22	168.98	124.42	1,159.60	569.52	6,897.34	9,851.53	
January 2023	57.91	148.33	182.83	127.04	1,278.48	589.36	7,801.39	8,604.40	
February 2023	53.38	134.23	170.49	123.47	1,160.86	561.25	7,127.11	9,535.37	
March 2023	49.97	116.73	154.74	118.57	1,012.75	543.47	6,529.00	8,839.80	
April 2023	42.95	77.73	121.80	106.59	684.19	470.36	4,981.99	8,791.23	
May 2023	40.08	55.02	102.87	107.52	506.97	458.98	3,636.48	5,557.01	
June 2023	36.32	38.90	89.45	108.83	372.73	433.83	2,887.68	5,483.51	
July 2023	34.65	31.90	83.65	110.39	314.49	422.00	2,685.58	5,403.99	
Total Annual RPC	**$ 526.68**	**$ 959.32**	**$ 1,490.90**	**$ 1,374.60**	**$ 8,600.68**	**$ 5,849.41**	**$ 57,656.03**	**$ 88,710.22**	
August 2022	$ 44,944	$ 894,177	$ 412,481	$ 90,961	$ 213,617	$ 109,877	$ 79,231	$ 184,668	
September 2022	48,417	1,116,669	459,524	95,498	260,039	115,676	89,588	205,862	
October 2022	52,486	1,636,165	543,566	93,250	390,109	126,788	121,648	210,618	
November 2022	59,123	2,552,307	700,820	95,341	580,499	140,787	162,817	304,726	
December 2022	69,093	3,689,265	893,058	101,654	800,125	159,467	206,920	325,101	
January 2023	71,061	4,157,646	975,755	102,771	888,543	163,842	226,240	309,758	
February 2023	66,459	3,762,944	910,583	99,396	810,279	155,467	206,686	343,273	
March 2023	59,765	3,284,521	828,762	96,157	709,941	151,085	189,341	318,233	
April 2023	51,625	2,183,386	652,587	86,445	480,301	130,761	144,478	316,484	
May 2023	49,174	1,549,127	534,628	88,060	354,371	127,595	105,458	205,609	
June 2023	45,079	1,087,960	465,767	90,764	261,660	121,037	83,743	202,890	
July 2023	43,550	893,206	432,236	92,620	217,942	117,737	77,882	199,948	
Total Revenue	**$ 660,776**	**$ 26,807,374**	**$ 7,809,766**	**$ 1,132,918**	**$ 5,967,425**	**$ 1,620,119**	**$ 1,694,032**	**$ 3,127,171**	**$ 48,819,581**
New Customer Growth (Decay)	$ (11,640)	$ 1,083,417	$ 5,915	$ (10,018)	$ (89,461)	$ 61,252	$ (93,305)	$ 199,734	**$ 1,145,894**

DOE Position:

Approved	$ 47,673,687	Allowed Revenue	$ 48,819,581 CC * RPC
Actual Revenue	44,506,322	Actual Revenue	$ 44,506,322
Difference	$ (3,167,365)	Decoupling Adj (Under)/Over	$ (4,313,259)

Disallow Difference $ (1,145,894) Change in Revenue Associated with Customer Growth