STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE PUBLIC UTILIITES COMMISSION

Docket No. DG 23-086
Northern Utilities Inc.
Petition for Approval of Revenue Decoupling Adjustment Factor

Supplemental Technical Statement of Faisal Deen Arif, Gas Director &
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Department of Energy, Division of Regulatory Support
January 25, 2024

The New Hampshire Department of Energy ("DOE" or the "Department") submits this supplemental technical statement[1] pursuant to the proceedings in Docket No. DG 23-086 and the revised procedural schedule approved by the Public Utilities Commission ("PUC" or the "Commission") through a Procedural Order dated January 5, 2024.[2]

This statement pertains to the overall claim of $4,313,259 (hereafter referred to as $4.3 million) in the 2022-23 Revenue Decoupling Adjustment Factor (RDAF) by Northern Utilities Inc. ("Northern", or "the Company").

The purpose of this statement is to provide the Commission with additional information on the Department's analytical findings in an effort to validate Northern's overall ask of $4.3 million from their first Decoupling Year ("DY1"[3]) over the 2022/23 period.

The Department supports Northern's capped RDAF ask of $1,891,519 as just and reasonable and in the public interest. Consequently, the DOE continues to recommend their collection over the 2023/24 COG recovery period. The underlying calculation for the application of the 4.25 percent cap resulting in the said amount appear to be consistent with the Settlement Agreement in Docket No. DG 21-104. The Department preliminarily concludes that the total RDAF ask from DY1 should be $3,167,365. Amounts over the cap are deferred and subject to further review in connection with the overall Revenue Decoupling Mechanism (RDM) and the current RDAF formula.

The current technical statement is a supplement to DOE's initial statement as both statements relate to issues that are inherent to the proposed RDM by Northern and the resulting RDAF ask in DY1.

[1] The first technical statement (the "initial Technical Statement") was submitted on December 8, 2023. *See* Tab 22 in DG 23-086.
[2] *See* Procedural Order Re: Proposed Amended Procedural Schedule.
[3] DY1 spans the time period August 1, 2022 to July 31, 2023.

The current technical statement is organized as follows:

1. Background
2. Summary of Docket Activity
3. RDAF Analytical Framework
4. Summary of DOE Analysis
5. DOE Observations
6. DOE Recommendations

1. Background

Pursuant to Section IX of Northern's current Tariff 12, the Company made its initial "Petition for Approval of Revenue Decoupling Adjustment Factor" (RDAF) on September 15, 2023. While Northern's overall RDAF claim remains at $4.3 million, following Sub-section 8.0[4], the RDAF ask is capped at $1,891,519 (hereafter $1.9 million) in the instant docket.

Because this was the first implementation of the Northern's RDAF, the Department worked with the Company to conduct discovery. *See* DOE Assented-To Motion To Expand Time Allotted For Investigation (October 10, 2023). Through its October 18, 2023 Procedural Order[5], the Commission granted DOE's motion. The Commission also approved the Company to collect $1.9 million over the 2023/24 Gas Season on an interim basis, pending further review and hearing, and suspended the non-peak RDAF tariff. *See* Order *Nisi* No. 26,896 dated October 31, 2023.

The Department's initial technical statement did not include its final conclusions or recommendations; it noted that discovery responses from Northern were not yet due, and that a future updated DOE statement would be provided when discovery is concluded. *See* DOE Tech Statement (December 8, 2023). On December 22, 2023, Northern submitted a letter stating rebuttal was not possible and seeking a revised procedural schedule. The DOE filed a proposed revised procedural schedule including the DOE's submission of conclusions and recommendations regarding the matters at issue in this docket, and an opportunity for Northern thereafter to conduct discovery and to file rebuttal, as planned in the original procedural schedule. *See* DOE Proposed Revised Procedural Schedule (December 29, 2023). The Commission approved the proposed schedule. *See* Procedural Order Re Proposed Revised Procedural Schedule (January 5, 2024).

[4] In Sub-section 8.0, it states:

> "The RDA for each Adjustment Period, determined in accordance with Section 5.0, may not exceed four and one-quarter percent (4.25%) of approved distribution revenues as established in the Company's most recent base rate case, including any adjustment due to a step."

[5] *See* Procedural Order Re: Company, OCA, and DOE Motions and Cancelling October 23 Hearing (Oct. 13, 2023); Procedural Order Re: Deadline for DOE Position Statement (Oct. 18, 2023).

2. Summary of Docket Activity

The Department issued a total of four sets of Data Requests ("DRs") to the Company[6]:

- DOE Set 1 on October 2, 2023, which Northern responded to on October 12, 2023;
- DOE Set 2 on November 8, 2023, responded to on November 20, 2023;
- Technical Session DR Set 1 on December 4, 2023, responses provided by the Company on December 11, 2023; and
- DOE Set 3 on December 6, 2023, to which Northern responded[7] on December 14, 2023.

A technical session was held on November 30, 2023.

The DOE filed its initial technical statement on December 8, 2023, at which time all data responses from Northern were not yet due. Since then, the Department received information and gained additional understanding. The current supplemental statement is informed by the relevant information.

3. RDAF Analytical Framework

Northern's current RDAF is structured after a *Revenue Per Customer* ("RPC") model. This model along with its specific RPC values for each rate class were developed in the Company's last rate case, Docket No. DG 21-104, using the 2020 Test Year ("TY") billing determinants[8].

The Revenue Decoupling Mechanism (RDM) was proposed to "addresses the basic misalignment between the structure of the Company's costs and its rates". Since the "utility distribution costs are largely fixed and change very little in the short run with changes in usage levels" but "distribution rates have a significant variable, or usage-based, component that changes revenues (and cost recovery) with changes in usage levels", the RDM was proposed to "correct for this misalignment by adjusting the Company's actual revenues to match its authorized revenues[9]." [10] Additionally, the proposed RPC-based decoupling model was designed to correct "an inherent financial disincentive for utilities to promote [Energy Efficiency] initiatives that reduce customer consumption"[11]. For a greater discussion on the specifics of Northern's proposed Revenue Decoupling Mechanism (RDM) and the RPC model. *See* Dkt. No. DG 21-104, Exhibit 3, Direct Testimony of Timothy S. Lyons at Bates 001143-1166 and Attachments T. Lyons at Bates 001167-1179.

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[6] *See* Attachment A and B from initial technical statement for Northern's responses to DOE Set 1 and Set 2, respectively. *See* also Attachment 1, Responses to TS DR Set 1.

[7] That is, a response indicating inability of Northern's current billing system to perform and provide the requested DOE information. *See* Attachment 2, Northern Responses to DOE Set 3.

[8] The billing determinants, among others, included: i) the number or count of customers per rate class, per month; and ii) the total therm sales per rate class, per month.

[9] The "authorized revenue" was calculated on a per customer class basis in DG 21-104. *See* Attachment SED-2.

[10] *See* DG 21-104 Exhibit 3 at Bates 001143-1166 , Direct Testimony of Timothy S. Lyons; p 2 of 22, lines 6-17.

[11] *See* DG 21-104 Exhibit 3, at Bates 001143-1166, Direct Testimony of Timothy S. Lyons; p 10 of 22, lines 5-9.

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[12]. Without undermining the significance of this limitation, in DOE's view, Northern appears to have followed the calculation methodology as stipulated in the Settlement Agreement in DG 21-104. This fact was accounted for in DOE's current recommendations.

In the course of discovery in this docket, DOE's analysis has generated concern about the RPC model in general. The development of Northern's current RPC model, inherently, reflects an average energy consumption behavior (i.e., the Usage Per Customer, UPC, or simply the usage) by the customers for every rate class, and over a given unit of time (here, monthly). With changes in the unit price of the commodity (i.e., price per therm for a regulated gas utility) between the Test Year ("TY")[13] and the Decoupling Year ("DY1"), such usage would naturally vary as a response to varying unit prices. The price elasticities would capture such variations. Any UPC variation beyond what can be explained by the price response could be attributed to all other factors (including but not exclusively, the energy efficiency). Using data provided by Northern, within the DOE's current analytical framework, the Department estimates this price response and its impact on the current RDAF ask.

Additionally, the *per customer* structure of the RPC model implies that the Company is entitled to a certain amount of decoupled revenue for every customer it finds in the subsequent periods. This immediately draws attention to three factors: a) the customer count methodology; b) the impact of customer growth over time on the RDAF ask; and c) the cost recovery components that were inherent in the allowed revenue requirement calculation.[14]

Taken together, it implies that the current RDAF ask could be explained by the observed variation between the Test Year (TY2020) and the Decoupling Year (DY 2022/23 or DY1) in terms of:

i) The variation in customer count (i.e., the customer growth aspect);
ii) The variation in price per therm; and/or
iii) The variation in UPC (i.e., the price response and the non-price response aspects).

This provides the basis for the Department's current analytical framework. *See* Attachment 3 for a detailed exposition of the theoretical and empirical models used by the Department.

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[12] This includes inability for Northern's billing system to compare the unbilled revenue from the prior month to billed revenue in the current month, essentially to replace an "estimate" with the corresponding "actual" data.
[13] When RDM was designed.
[14] The interplay between "embedded costs", "average costs", and "marginal costs" and their impacts in the final class-level revenue requirements bear significance for an RPC decoupling structure.

4. Summary of DOE Analysis

Based on the information sourced from DG 21-104, from DG 23-086 and the Company's data responses, the following is a summary of Department's analytical findings[15]:

4.1 We observe that Northern has a *Revenue Per Customer* (RPC) decoupling structure. Three variables are of primary interest under an RPC structure. These include:

a. The commodity unit price, *p*, measured in terms of price per therm;
b. The customer count, *n*, measured using the Company methodology;
c. The usage per customer (UPC), *q*, measured in terms of average therm consumption.

These are our variables of interest. *See* Attachment 3 for an overview of DOE's analytical models.

4.2 Any RDAF ask could be explained by:

a. Significant (in the sense of statistical significance) variation in customer numbers (i.e., customer growth factor) between TY2020 and DY1 at levels;
b. Significant variation in usage per customer (i.e., the UPC factor) between the same timeframes; or
c. A combination of both.

4.3 Do we observe any difference in these variables? More specifically, do we observe:

a. The difference at levels? In other words, do we see any differences for the variables of interest between their TY2020 level and their DY1 level; and
b. (more importantly) Is there any statistically significant differences in those variables that can related to the current RDAF ask? The answer to the latter question also bears policy significance.

The DOE's analysis attempted to answer these questions.

4.4 In comparing the variables at level, we observe:

a. Northern had 34,530 customers in an average month in TY2020. In the DY1 year (i.e., between August 2022 and July 2023), they reported 36,222 customers in an average month. This indicates a 4.9% customer growth on an average-month basis.

b. At the Company level, Northern reported an average usage of 166.8 therms per month in TY2020. In DY1, it is reported to be 159.8 therms per month; registering a fall of 3.7% on an average-month basis.

c. In terms of price per therm, gas prices are observed to vary significantly both across rate classes and over time. Overall, the price per therm rose by 89% between TY2020 and DY1. This temporal price variation, however, is different between the sectors. While price per therm rose by 100.6% on an average-month basis for the residential sector, the

[15] For all relevant values, please refer to the Tables in Attachment 4 (provided in live format).

C&I price rose by 68.8%. These differences are significant as they would elicit different usage and gas consumption behavior depending on the price elasticity of the specific sectors.

4.5 In comparing the variables of interest at the sectoral level, we observe:

a. In the residential sector, the reported average number of customers per month in TY2020 was 27,582. It is reported to be 29,155 in DY1. This registers a 5.7% residential customer growth. Interestingly, however, the R-6 (i.e., the non-heating residential customers) registers a negative growth of 4.3%, while the R-5 & R-10 classes (i.e., the heating customers) register a positive growth of 6.2% on an average-month basis.

b. The C&I sector, on the other hand, reported a total of 6,948 customers on an average month during TY2020. This increased to 7,068 customers in DY1; reporting a 1.7% customer growth.

c. In terms of usage per customer (UPC), the residential customer reported an average use of 54.4 therms per month in TY2020. This reduced to 48.5 therms per month in DY1; registering an 11.4% decline in UPC per month. The corresponding UPC values for R-6 class are 14.8 therms in TY2020 and 14.9 in DY1 (i.e., the UPC increased for R-6 customers). For the R-5 and R-10 customers, the UPC figures are 56.4 therms in TY2020 and 49.9 therms in DY1. It is important to note that the DY1 UPC figures are inclusive of the observed customer growth the occurred between TY2020 and DY1.

d. Variations in the C&I sector are significant both across its six separate rate classes[16] as well as in terms of their variability across time (i.e., TY2020 versus DY1). *See* Attachment 4 for a review of the observed variations. Overall, while the UPC for an average C&I customer was 610.4 therms per month in TY2020, it is 617.2 therms in DY1, registering an increase of 1.6% on an average-month basis.

4.6 Taken together, the observed variations would validate Northern's current RDAF ask at levels. The question is whether it also validates the claim from a statistical perspective.

4.7 This inquiry led DOE to perform statistical analysis. *See* Attachment 3 for an overview of the statistical models.

4.8 In comparing the variables of interest for statistical significance, we observe:

a. Customer growth between TY2020 and DY1 is statistically significant in terms of explaining Northern's total RDAF ask. This implies that customer count in TY2020 is significantly different from that of DY1, indicating that, from a statistical perspective, the customer growth is predominantly responsible for the current RDAF ask.

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[16] That is, G-40, G-41, G-42, G-50, G-51, and G-52. G-42 and G-52 classes represent large customers. For example, UPC in G-42 class in TY2020 was 14,216.5 therms per month that declined to 13,508.8 therms per month in DY1, a decline of 708 therms per month between the two time periods.

b. When looked at the sectoral level, while customer count is found to be a statistically significant variable for the residential sector, it is not for the C&I sector. This could imply potential cross-subsidization issues between the sectors that could be attributed to the current RPC structure.

c. Overall, estimates from the data indicate that a 1% increase in customer growth would lead to a 1.75% increase in RDAF ask (1.45% for residential and 1.96% for C&I). In terms of levels, the estimates show that one additional customer added to the distribution system (i.e., the marginal customer) would increase the RDAF ask for all customers by $11.16 per month (or $134 annually). The corresponding figures vary across residential and C&I sectors. While the marginal customer in the residential sector raises RDAF ask for all residential customers by $136 annually, it is observed to be $72 per year for C&I marginal customer. These estimates are all statistically significant[17] which is indicative of growth impact on the current RPC decoupling structure.

4.9 A comparison of the usage difference between TY2020 and DY1 is not straight forward. It is because per customer gas usage can vary for multiple reasons. This, however, can be categorized in terms of UPC variation due to price changes (i.e., the price response), and the UPC variation for other reasons (i.e., the non-price response). The latter category can include, among others, usage variation due to the Energy Efficiency program run by the utility. *See* also Northern's response to DOE 1-9 provided with Arif & Alam's initial Technical Statement (December 8, 2023), Attachment A.

4.10 The price response to UPC variation can be measured through price elasticities. The residential sector is observed to be highly price elastic although the elasticity for Northern's overall gas demand is found to be slightly inelastic (-0.94)[18]. The observed overall inelastic nature of gas demand could be largely attributed to inelastic demand by the C&I sector.

4.11 The high price elasticity of the residential demand coupled with the observed hike in gas price per therm between TY2020 and DY1 would imply that the residential sector would have responded by more than proportionally decreasing its sectoral gas demand. This would manifest in terms of significant reduction in usage per customer despite the observed growth in customer count. Indeed, between TY2020 and DY1, the residential UPC fell from 54.4 therms to 48.9 therm on an average-month basis (or by 1,924,230 therms in total in DY1[19]).

4.12 The price elasticity would also allow for an estimation of the non-price responses to UPC. Consequently, due to the non-price responsiveness, the estimation indicates that the residential UPC fell from 54.4 therms to 50.5 therms on an average-month basis between

[17] All observations are significant at 95% at least. *See* Attachment 4.
[18] Both price elasticities are found to be statistically significant.
[19] That is, (48.9 – 54.4) x 12 months x 29,155 residential customers in DY1.

TY2020 and DY1 (or by 1,364,454 therms in total in DY1[20]). In other words, the collective non-price response accounts for a total reduction of 559,776 therms. *See also* Arif & Alam's initial Technical Statement (December 8, 2023), Attachment A, Northern's response to DOE 1-9.

4.13 With an average price per therm of $1.9410 during DY1 period, this represents a revenue loss of $1,086,536 in DY1 due to all non-price induced reduction in therm usage by residential customers' collective conservation effort (and partially due to Energy Efficiency program geared towards the residential sector). The Department observes that the RDAF ask of residential sector by Northern, however, is $3,809,826. *See* p 1 of Attachment SED-1 filed with Northern's petition in DG 23-086.

5. DOE Observations

5.1 We first observe that Northern has a Revenue Per Customer (RPC) decoupling Structure, that was proposed as a Revenue Decoupling Mechanism (RDM) in DG 21-104, Northern's last distribution rate case, and approved by the Commission in Order No. 26,650 (July 20, 2022).

5.2 The RDM was proposed to "addresses the basic misalignment between the structure of the Company's costs and its rates". Additionally, the proposed RPC-based decoupling model was designed to correct "an inherent financial disincentive for utilities to promote [Energy Efficiency] initiatives that reduce customer consumption". *See* Dkt No. DG 21-104, Exhibit 3, at Bates 001143-1166, Direct Testimony of Timothy S. Lyons and Exhibit 3, at Bates 001167-1179, Attachments T. Lyons.

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 revenues.

5.4 Northern's authorized revenue in DG 21-104 was $47,673,687. *See* Attachment SED-2 filed with Northern's petition in DG 23-086. 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.

5.5 For the Decoupling Year (DY1) under consideration, Northern reported to have earned a total base revenue of $44,506,322. *See* pp 10-10 of Attachment SED-1 (Northern's petition in DG 23-086). 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

[20] That is, (50.5 – 54.4) x 12 months x 29,155 residential customers in DY1.

would be $1,145,894 (approx. $1.15 million)[21] 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.

5.6 This additional RDAF ask of $1.15 million is a consequence of the current RPC structure.

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

a. First, the class-level RPCs were developed in Northern's last rate case, DG 21-104. The development those RPCs made use of two factors: the exiting number of customers in TY2020, and the allowed revenue requirement figures that were derived using Northern's FCOSS and MCOSS[22]. Simply put, the RPC is the revenue requirement divided by the number of customers. As such, all utility costs inclusive of planned redundancies are inherently included in the approved revenue requirements. The use of RPC beyond the TY, therefore, implies that all of those costs are instantly realized with the addition of a marginal customer (i.e., the last customer added to the distribution system). This is not necessarily the case in utility management since some costs are incurred in discreet blocks (e.g., main extension with planned redundancies, payroll expense etc.) As such, this creates a distinction between, what Northern called, the "embedded costs" (which is largely the "average costs") and the "marginal costs". This was highlighted in testimonies in DG 21-104. *See* Docket No. DG 21-104 Exhibit 3, at Bates 001025-1072, Direct Testimony of Ronald J. Amen and John D. Taylor and Exhibit 3 at Bates 001073 -1142 Attachments R. Amen and J. Taylor (missing RAJT-1). Northern's class-level revenue requirements included the "embedded costs" with planned redundancies. As such, so long as the Company realizes its authorized revenue requirements, the Company is sufficiently compensated inclusive of its plan redundancies. In the context of RPCs, therefore, any RDAF revenue beyond the authorized revenue requirement would unduly harm the ratepayers.

b. Second, the RPC structure does not put any cap on the level of revenue requirement that the Company can realize. Thus, Northern is seeking an additional $1.15 million in their total RDAF ask in DY1.

c. Third, when the marginal costs are lower than the embedded costs, the use of RPC would over-compensate the Company and unduly harm the ratepayers.

d. Forth, the misalignment is further accentuated by periodic updates to RPCs through the authorized step-adjustments. In other words, while the step-adjustments compensate

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[21] $1,145,894 is the difference between the $4,313,259 and DOE's initial proposal of $3,167,365.

[22] The Functional Cost of Service Study (FCOSS) and the Marginal Cost of Service Study (MCOSS). *See* the Direct Testimony of Ronald J. Amen and John D. Taylor and Attachments R. Amen and J. Taylor.

the utility for their additional capital investments, it also carries the same assumption of embedded costs being equal to marginal costs.

e. Fifth, the *per customer* structure does not allow for price responsiveness aspect to usage adjustments into consideration. When per therm price goes up, through price elasticities, the customers respond by reducing gas demand. This creates natural usage variations. However, depending on the price elasticity in different sectors, namely residential vs C&I, this may create opportunities for cross-subsidization between the sectors, even within the authorized revenue requirement.

f. Finally, the RPC structure creates misalignment in terms of compensating the Company for both the reduction in average usage and also for its growth in customer base.

5.8 Based on the above, any amount beyond the authorized revenue requirement would not be just, reasonable and in the public interest.

6. DOE Recommendations

In light of the foregone analysis, the presented information, and given the circumstances, including the Settlement Agreement in Docket DG 21-104, which could be reasonably interpreted by the Company as allowing it to do what it did, the scope of this docket, and adherence to the mathematical formula, the relief requested appears to be just and reasonable and in the public interest.

However, the Department's position should not be construed as waiving its regulatory obligation to raising and taking a position in a future docket that the RDAF formula itself is not just, reasonable and in the public interest, or that the terms of the settlement in the rate case that led to the current RDAF formula should be otherwise modified.

Accordingly, the Department:

- Continues to support Northern's capped RDAF ask of $1,891,519 to be recovered through the ongoing 2023/24 COG Season as consistent with the Settlement Agreement reviewed and approved by the Commission in Order No. 26,650 at 4-5, 13-14, 21 in Docket No. DG 21-104, and thus just and reasonable and in the public interest; and

- Further preliminarily concludes that Northern be allowed to collect up to $3,167,365 in RDAF ask, instead of the requested cumulative $4,323,259, from the 2022/23 Decoupling Year subject to further review of the overall Revenue Decoupling Mechanism (RDM) and the current RDAF formula.