UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): March 26, 2020

UNITIL CORPORATION
(Exact name of registrant as specified in its charter)

New Hampshire	1-8858	02-0381573
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

6 Liberty Lane West, Hampton, New Hampshire	03842-1720
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (603) 772-0775

N/A
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol	Name of each exchange of which registered
Common Stock, no par value	**UTL**	**New York Stock Exchange**

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 7.01 Regulation FD Disclosure

The final Order of the Maine Public Utilities Commission ("MPUC"), which was issued in two parts, to which Item 8.01 below refers, is attached as Exhibit 99.1 and Exhibit 99.2 to this Current Report on Form 8-K.

Item 8.01 Other Events

The MPUC issued its final Order (the "Order") in Docket No. 2019-00092, the distribution base rate case filed with the MPUC on June 28, 2019 by the Maine division of Northern Utilities, Inc. (the "Company"), Unitil Corporation's natural gas utility subsidiary operating in Maine and New Hampshire. The Order was issued in two parts. Part I was issued on March 26, 2020 and Part II was issued on April 1, 2020.

The Order approves an increase in operating revenues of $3.6 million, effective April 1, 2020. The distribution base rate case is based on the Company's operating costs and investments in utility plant for a test year ended December 31, 2018, as adjusted for known and measurable changes. The Order provides for a return on equity of 9.5 percent and a capital structure reflecting 50% equity and 50% long-term debt.

Item 9.01 Financial Statements and Exhibits

(d) Exhibits

Number	Exhibit
99.1	Maine Public Utilities Commission Order (Part I) dated March 26, 2020
99.2	Maine Public Utilities Commission Order (Part II) dated April 1, 2020
104	Cover Page Interactive Data File – The cover page interactive data file does not appear in the interactive data file because its XBRL tags are embedded within the inline XBRL document.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

UNITIL CORPORATION

By: /s/ Laurence M. Brock

Laurence M. Brock
Senior Vice President, Chief Financial Officer and Treasurer

Date: April 7, 2020

Exhibit 99.1

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2019-00092

March 26, 2020

NORTHERN UTILITIES, INC. d/b/a UNITIL
Request for Approval of Rate Change
(35—A M.R.S. § 307)

ORDER (Part I)

BARTLETT, Chair; WILLIAMSON and DAVIS, Commissioners

I. SUMMARY

With this Order (Part I), under 35-A M.R.S. § 307 the Commission approves an annual base-rate revenue requirement for Northern Utilities, Inc. d/b/a Unitil (Northern or the Company) of $50,038,571.[1] This is an increase of $3,605,412, or 7.8%, over the test-year revenue requirement. This compares to Northern's request for a 15% increase. For an average residential customer taking heating service from Northern, the approved increase equates to a 3.5% increase in the average monthly bill. These new rates will take effect April 1, 2020.

In setting these new rates, the Commission approves for inclusion in rate base a portion of the Company's investment in a new customer information system, or CIS, and orders that a third-party audit be initiated to examine the prudence of the remainder of the expenditures Northern incurred in the implementation.

Also, the Commission rejects the Company's proposal to establish the capital investment recovery adjustment, or CIRA, and orders certain modifications to the Company's targeted area buildout, or TAB, programs in Saco and in Sanford.

II. TWO-PART ORDER

This Order (Part I) summarizes the Commission's key decisions in this proceeding. The Commission's procedural rules allow it to issue an order in two parts "[i]n extraordinary circumstances, including those in which a deadline . . . requires the issuance of a decision by a specific date . . . ." MPUC Rules, ch. 110, § 11(C)(2). There is only a brief period between the Commission's deliberations and the date new rates go into effect. Also, due to the emergence of the global pandemic known as COVID-19,[2]

1 The calculations supporting this revenue requirement are shown in Appendix A to this Order (Part I).

2 *See* Me. Exec. Order No. 19 FY 19/20 (Mar. 24, 2020), https://www.maine.gov/governor/mills/ sites/maine.gov.governor.mills /files/inline-files/An%20Order %20Regarding%20Essential%20Businesses%20 and%20Operations%20_0.pdf; Me. Exec. Order No. 14 FY 19/20 (Mar. 18, 2020), https://www.maine.gov/governor/m ills/sites/maine.gov.governor.m ills/files/ inline-files/Executive%20Order%20to%20 Protect%20Public%20Health%20.pdf; Proclamation of State of Civil Emergency to Further Protect Public Health (Mar. 15, 2020), https://www.maine.gov/governor/m ills/sites/maine.gov.governor. mills/files/inline-files/ Proclamation%20of%20State%20of%20Civil %20Emergency%20To%20Further%20Pr otect%20Public%20Health.pdf.

the Commission and its Staff are working remotely, potentially making it difficult to issue a full order before the rate-effective date of April 1, 2020. Thus, the Commission finds that "extraordinary circumstances" exist to support the issuance of this order in two parts. Order (Part II) will provide the complete background, analyses, and reasoning underlying the Commission's decision, and will be issued as soon as practicable.

III. REVENUE REQUIREMENT

A. Rate Base

1. Calculating Rate Base

To calculate rate base, the Commission approves the use of year-end rate base with a total adjustment to revenues of $921,922 to account for sales growth from the year-end investments. This amount is the combination of Northern's sales growth in 2018, its annualized sales growth from new customers in January 2019, and the Staff's and OPA's recommended adjustment to revenues for annualized sales growth from new customers from February through July 1, 2019.

2. Implementation of New Customer Information System

Northern has sought to include in rate base 22% of the full cost ($36.8 million) of implementing a new customer information system (CIS) to serve Unitil Corp.'s regulated utility subsidiaries.

The Commission finds that 22% is the appropriate allocation factor to be used for assigning the costs of the CIS implementation to Northern.

The Commission also finds that Northern has failed to carry its burden of proof that the total cost of implementing its new CIS was prudently incurred. The Commission finds, however, that a portion of the total CIS cost—the originally budgeted amount of $12.7 million—was prudently incurred and that Northern's allocated share of that amount may therefore be put into rate base in this proceeding.

The Commission concludes that it is appropriate to examine the prudence of the remainder of the costs and therefore initiates a management audit of Unitil's implementation of the CIS. The audit will be conducted under 35-A M.R.S. § 113 in a separate proceeding after this docket closes. The Commission will select the auditor and Northern shall pay the costs of the audit. The Commission will decide, based upon the results of the audit investigation, whether to allocate some or all of the remaining audit costs to Northern's ratepayers.

The Commission may conclude, following the audit and subsequent adjudicatory proceeding, that the entire $36.8 million was prudently spent, or that, in addition to what the Commission has allowed here, some amount less than that total was prudent. If so, Northern will be allowed to seek to add those costs to rates in its next Targeted Infrastructure Replacement Adjustment (TIRA) case, or next general rate case, whichever occurs first.

Until the audit investigation is completed, Northern may continue to reflect any CIS-related amounts on its books.

Finally, the Commission orders the Company to develop a written document-retention policy that includes information on how the policy will be communicated to new and existing employees, and to submit that policy for informational purposes as a compliance filing within 90 days of this Order (Part I).

B. Cost of Capital and Capital Structure

The Commission approves a return on equity (ROE) of 9.48% (including an adjustment for flotation costs of 8 basis points) with a capital structure of 50% equity and 50% debt. The Commission finds the cost of long-term debt of 5.19% to be reasonable and thus approves it. These decisions produce an after-tax weighted-average cost of capital (WACC) of 7.34%.

The calculation of the Company's TIRA revenue requirement necessitates establishing a pre-tax WACC. *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 60 (Feb. 28, 2018). For purposes of calculating the TIRA revenue requirement, the pre-tax TIRA rate of return is set at 9.18%. The Company shall use an ROE of 9.48% for purposes of applying the TIRA Earnings Sharing Mechanism.

IV. RATE DESIGN

The rate increase shall be applied as an equal percentage increase across the board to all rate elements (fixed monthly charges, head blocks, tail blocks) and all rate classes.

V. PROPOSED CAPITAL INVESTMENT RECOVERY ADJUSTMENT

The Commission hereby rejects the Company's proposal to establish the CIRA.

VI. TARGETED AREA BUILDOUT PROGRAMS IN SACO AND IN SANFORD

A. Expansion to So-Called Adjacent Areas

With respect to the Company's proposed amendment regarding "adjacent areas," the Commission finds that the amendment is reasonable. "Adjacent areas" may include only areas that are in close proximity to the original TAB area, along the lines of the definition the Company proposed in response to EXM-002-058. The Company should include language to this effect in its amendment to the TAB tariff.

The Commission also determines that in the future Northern must make a filing before it expands to an adjacent area. The filing shall include, at a minimum, the following information: (a) a map of the adjacent TAB area (as part of the whole TAB area) and a description of the area, the proposed investments in the area, and the justification for those investments; (b) the TAB model and surcharge calculation assuming the new investment and revenue that would result from expanding to the adjacent area; and (c) a demonstration that the revenue from the existing surcharge is adequate to cover the cost of the incremental expansion and is appropriate to be charged to the customers in the new, adjacent area. This will allow the Commission and the parties to confirm that the existing surcharge remains reasonable and appropriate. This filing is for informational purposes, but, if an expansion warrants revision to the surcharge, the Company would be required to submit the TAB tariff with proposed changes to the surcharge to the Commission for approval.

B. TAB Revenue Targets and Incentive Mechanism

The Commission finds that the targets for the Saco TAB incentive mechanism should be revised to reflect the incremental customers and sales expected in the Shannon Woods and Mill Brook areas. The targets should be structured using customer and sales levels instead of rate levels, and the revenue targets should be calculated using the actual surcharge and base rates in effect during the applicable period. For this case, because the results of that methodology are not in the record, the Commission will use Exhibit 3 to Northern's March 12, 2020 exceptions in assessing whether adjustments are necessary under the incentive mechanism; the Commission finds that no adjustments are necessary at this time.

Finally, the Commission agrees with the Staff's recommendation that, for the same reasons the Commission approved such a mechanism for the Saco TAB, an incentive mechanism should be adopted for the Sanford TAB that uses the same structure as the Saco TAB (as modified by our decision in this case) but with targets specific to the Sanford TAB, as established by the customer and sales assumptions set out in Docket No. 2017-00037, and using the same methodology as established for the Saco TAB. Any rate adjustments indicated by the Sanford TAB would be reflected in subsequent base rate proceedings.

VII. CONCLUSION

Accordingly, the Commission

O R D E R S

1. That Northern is granted an annual base-rate revenue requirement of $50,038,571, with new rates to go into effect April 1, 2020;

2. That Northern shall submit its applicable schedules of rates and terms and conditions reflecting the changes set out in this order by **4:00 p.m. on Friday, March 27, 2020**, for a compliance review;

3. That the rate increase shall be applied across the board evenly to all rate classes and rate components;

4. That this new revenue requirement reflects a return on equity of 9.48%, a cost of long-term debt of 5.19%, and a capital structure of 50% common equity and 50% debt;

5. That, for purposes of calculating the TIRA revenue requirement, the pre-tax TIRA rate of return is set at 9.18%, and the Company shall use an ROE of 9.48% for purposes of applying the TIRA Earnings Sharing Mechanism;

6. That these approved rates reflect the inclusion in Northern's rate base of 22% of $12.7 million of USC's CIS implementation investment;

7. That a management audit under 35-A M.R.S. § 113 be initiated for the purpose of examining the Company's implementation of its new customer information system. The audit shall be conducted by an appropriate consultant familiar with CIS implementations, to be selected by the Commission, who will examine the decisions made by management about the hiring and use of vendors and consultants as well as about the scope, schedule and costs of the implementation. The costs of the audit shall be borne by the Company with a possible allocation of some or all those costs to ratepayers depending on the outcome of the audit and investigation;

8. That, until the audit investigation is completed, Northern may continue to reflect any CIS-related amounts on its books;

9. That Northern develop a written document-retention policy that includes information on how the policy will be communicated to new and existing employees, and, submit that policy in this docket for informational purposes as a compliance filing **within 90 days of this Order (Part I)**.

10. That Northern's request to establish the CIRA is denied;

11. That the Company is permitted to amend its TAB tariff to address adjacent areas as discussed in this order;

12. That the Company shall make a filing with the Commission as described in this order for informational purposes prior to expanding any TAB area to an adjacent area;

13. That the Saco TAB incentive mechanism targets shall be revised to reflect the incremental customers in the Shannon Woods and Mill Brook areas, consistent with the assumptions set out in Exhibit 3 to Northern's exceptions;

14. That the Saco TAB incentive mechanism is hereby modified so that the targets are based on customer and sales levels instead of revenue targets;

15. That, consistent with the assumptions in Exhibit 3 to Northern's exceptions, no adjustment under the Saco TAB incentive mechanism is necessary at this time;

16. That an incentive mechanism for the Sanford TAB is adopted that uses the same methodology as the Saco TAB (as modified by this order), but with targets specific to the Sanford TAB as established by the customer and sales assumptions set out in Docket No. 2017-00037.

Dated at Hallowell, Maine, this 26th day of March, 2020.

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR:

Bartlett
Williamson
Davis

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party at the conclusion of the adjudicatory proceeding written notice of the party's rights to seek review of or to appeal the Commission's decision. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. ch. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)–(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note : The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

Exhibit 99.2

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2019-00092

April 1, 2020

NORTHERN UTILITIES, INC. d/b/a UNITIL Request for Approval of Rate Change
(35-A M.R.S. § 307)

ORDER (Part II)
(**Public/Redacted**)

BARTLETT, Chair; WILLIAMSON and DAVIS, Commissioners

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List of Appendices

I. SUMMARY

With this Order (Part II), under 35-A M.R.S. § 307 the Commission approves an increase in the annual base-rate revenue requirement for Northern Utilities, Inc. d/b/a Unitil (Northern or the Company) of $3,605,412[1] over test-year revenues.[2] For an average residential customer taking heating service from Northern, the approved increase equates to an approximate 3.5% increase in the total average monthly bill. These new rates will take effect April 1, 2020.

In setting these new rates, the Commission approves for inclusion in rate base a portion of the Company's investment in a new customer information system, or CIS, and orders that a third-party audit be initiated to examine the prudence of the remainder of the expenditures incurred in the implementation.

Also, the Commission rejects the Company's proposal to establish the capital investment recovery adjustment, or CIRA, and orders certain modifications to the Company's targeted area buildout, or TAB, programs in Saco and in Sanford.

II. PROCEDURAL BACKGROUND

On June 28, 2019, under 35-A M.R.S. §§ 307 and 312 and Chapters 110 and 120 of the Commission's Rules, Northern filed a request to increase its base natural-gas rates.[3] In its initial filing, Northern requested that the Commission approve an increase of $7,033,013 in annual base-rate revenues (7% over test-year operating revenues and 15.1% over test-year base-rate revenues) based upon a test year ending December 31, 2018, an overall return on rate base of 8.15%, and known and measurable adjustments to test-year revenues, expenses, and rate base. Northern calculated that this increase would result in an average bill increase for non-heating customers of $5.85 per month and, for heating customers, $9.90 per month.

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1 The calculations supporting this deficiency in the revenue requirement are shown in Appendix A to this Order (Part II). This is the same Appendix A that was included with Order (Part I), which issued March 26, 2020.

2 The $3,605,412 increase is a 7.8% increase relative to Northern's test-year base revenues of $46,433,159, and a 7.5% increase relative to Northern's weather-normalized base revenues of $51,401,625 using its May 1, 2019 rates. Northern requested a base revenue requirement increase of 15%.

3 This is Northern's fourth request for a base rate increase since the end of an approximately 28-year period without any changes in rates. *See Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order at 1 (Feb. 28, 2018) (reducing rates slightly due to enactment of the Tax Cuts and Jobs Act of 2017); *Northern Utilities, Inc. d/b/a Unitil, Proposed Base Rate Increase and Rate Design Modification*, Docket No. 2013-00133, Order Approving Stipulation (Dec. 27, 2013) (authorizing rate increase with an estimated average bill increase of, among others, 1% for residential heating customers); *Northern Utilities, Inc. d/b/a Unitil, Proposed Base Rate Increase and Rate Design Modification*, Docket No. 2011-00092 Order Approving Stipulation at 1, 3 (Nov. 29, 2011) (authorizing rate increase with an estimated average bill increase of, among others, 16% for residential heating customers).

Northern also requested that the Commission approve a new capital tracking mechanism, which the Company called the capital investment recovery adjustment, or CIRA. Northern claimed that the proposed CIRA would allow it, outside of section 307 rate cases, to counter earnings erosion by recovering annually what it described as certain non-growth-producing or non-revenue-producing investments.

The Company also proposed to amend its targeted area buildout (TAB) tariff, which was approved in Docket No. 2015-00146 (for a TAB in the City of Saco) and Docket No. 2017-00037 (for a TAB in the City of Sanford), to allow it to expand into what it described as "adjacent areas" outside of the originally approved TAB areas in each municipality.

Northern also sought to change its rate design, based on two cost-of-service studies. Under these changes, Northern would move toward (1) recovering a larger portion of fixed infrastructure costs through the flat monthly customer charge and (2) reducing existing differences in rates of return between customer classes.

Northern's initial filing consisted of pre-filed testimony and exhibits from the following witness panels:

(1) introduction and overview by Christine L. Vaughan, Senior Vice President, Chief Financial Officer, and Treasurer (Overview Dir.);

(2) revenue requirement by Christopher J. Goulding, Director of Rates and Revenue Requirements, and Daniel V. Main, Assistant Controller (Rev. Req. Dir.);

(3) employee benefits and compensation by John F. Closson, Vice President of People, Shared Services and Organizational Effectiveness (Emp. Ben. Dir.);

(4) tax by Jonathan A. Giegerich, Tax Manager (Tax Dir.);

(5) implementation of the Company's new customer information system (CIS) by Laurence Brock, Controller and CAO, Justin Eisfeller, Vice President of Information Technology, and Mark Lambert, Vice President of Customer Relations (CIS Dir.);

(6) cost of capital by Robert V. Hevert of ScottMadden, Inc. (ROE Dir.);

(7) earnings erosion and justification for proposing the capital investment recovery adjustment (CIRA) by Timothy S. Lyons and Jennifer E. Nelson of ScottMadden, Inc. (Earnings Dir.);

(8) CIRA, TAB, and gas safety by Christopher J. LeBlanc, Vice President Gas Operations, Kevin E. Sprague, Vice President Engineering, and Mr. Goulding (Ops. Dir.);

(9) accounting-cost- and marginal-cost-of-service studies and rate design by Paul M. Normand of Management Applications Consulting (Rate Design Dir.); and

(10) rate impact and schedules of rates and terms and conditions by Christopher A. Kahl, Senior Regulatory Analyst (Rates Dir.).

A Notice of Proceeding, which provided interested persons the opportunity to intervene, was issued on June 28, 2019. On July 2, 2019, the Office of the Public Advocate (OPA) filed a petition to intervene, which was granted without objection at an initial case conference held on July 15, 2019.

On July 19, 2019, the Examiners issued a procedural schedule for the case. Technical conferences were held on the Company's direct testimony on August 28, 2019 and August 29, 2019.

On September 19, the OPA filed the testimonies and exhibits of Dr. Marlon Griffing on cost of capital and of Mr. Jerome Mierzwa on rate design. (In a supplemental filing on October 9, 2019, Dr. Griffing submitted a corrected version of his testimony.) On September 23, 2019, the OPA submitted the testimony and exhibits of Mr. Lafayette Morgan on revenue requirement. A technical conference was held on the OPA's direct testimonies on October 10, 2019.

On October 29, 2019, the Staff filed its Bench Analysis. A technical conference on the Staff's Bench Analysis was held on November 26, 2019. The first settlement conference was held among the parties and Staff immediately after the technical conference.

On December 9, 2019, the Company filed rebuttal testimony and exhibits of the following panels: (1) Mr. Brock, Mr. Eisfeller, and Mr. Lambert on the CIS implementation (CIS Reb.); (2) Mr. Goulding and Mr. Main on revenue requirement and the TAB programs (Rev. Req. Reb.); (3) Mr. LeBlanc, Mr. Sprague, and Mr. Goulding on the CIRA proposal; (4) Mr. Hevert on cost of capital and capital structure (ROE Reb.); and (5) Mr. Normand on rate design (Rate Design Reb.). On the same day, the OPA filed the rebuttal testimony of Mr. Mierzwa on rate design (Mierzwa Reb.) and of Dr. Griffing on cost of capital (Griffing Reb.). On December 10, 2019, the Company filed the rebuttal testimony of Mr. Lyons and Ms. Nelson regarding the CIRA proposal and earnings erosion (Earnings Reb.). In the rebuttal testimony, the Company provided an updated calculation of its revenue requirement showing a $7,252,785 deficiency.

On December 10, 2019, a public-witness hearing was held in Portland, Maine. One member of the public appeared and delivered sworn testimony.

On January 6, 2020, a technical conference was held on the Company's and the OPA's rebuttal testimonies. After this technical conference, a second settlement conference was held between the Company, the OPA, and the Staff. Over the next two days, additional settlement discussions and communications occurred. Ultimately, no settlement was reached.

On January 15, 2020, the Company and the OPA filed case management memoranda, and the Staff filed a Bench Memorandum. On the same day, the Company filed various updates to its revenue requirement, including in the areas of rate-case expenses, medical expenses, cost of debt, and others. These changes resulted in a slightly smaller revenue-requirement deficiency compared to its rebuttal—$7,071,095.

A prehearing conference was held January 17, 2020, and the hearing was held January 22, 2020. The parties filed initial briefs on February 14, 2020 and reply briefs on February 21, 2020. The Staff issued its Examiners' Report on March 5, 2020 and the parties filed exceptions thereto on March 12, 2020.

III. LEGAL STANDARD

A. Just and Reasonable Rates

In setting rates, the utility "is entitled to only those rates [that] are 'just and reasonable' under the circumstances."[4] A crucial objective in rate-setting is "to achieve a proper balance between the right of the utility's investors to earn a fair return on their investment and the right of ratepayers to a fair charge based on the value of the services provided by the utility."[5] In striking this balance, the Commission must weigh the competing public interests "in low utility costs" and in the "utility's continued operations."[6]

The Commission's findings of fact supporting its decision on the revenue requirement must be supported by substantial evidence in the record.[7]

4 *New England Tel. Tel. Co. v. Pub. Utils. Comm'n*, 390 A.2d 8, 30 (Me. 1978); 35-A M.R.S. § 301(3) (2010).

5 *New England Tel. & Tel. Co. v. Pub. Utils. Comm'n*, 448 A.2d 272, 288 (Me. 1982); *Am. Ass'n of Retired Persons v. Pub. Utils. Comm'n*, 678 A.2d 1025, 1030–31 (Me. 1996); *Cent. Me. Power Co. v. Pub. Utils. Comm'n*, 150 Me. 257, 278, 109 A.2d 512, 522 (1954) ("[T]he Commission must strike a nice balance between the essential revenue needs of the Company and the value of the service to the rate payer and his ability to pay.").

6 *Camden & Rockland Water Co. v. Pub. Utils. Comm'n*, 432 A.2d 1284, 1286 (Me. 1981); *see also Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) ("The rate-making process . . ., i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests.") (*quoted in New England Tel. & Tel. Co. v. Pub. Utils. Comm'n,* 390 A.2d 8, 14 (Me. 1978).

7 *Cent. Me. Power Co. v. Pub. Utils. Comm'n*, 150 Me. 257, 260, 109 A.2d 512, 513 (1954) ("[T]he basic question before us is whether or not the Commission has fixed reasonable and just rates, supported by substantial evidence, which will produce a fair return upon the reasonable value of the property of the Company used or required to be used in its service to the public within the state.").

B. The Prudence Standard

The law of prudence governs the Commission's regulation of the state's utilities. The Commission first gave clear guidance on the prudence standard in Maine in a 1985 decision known as *Seabrook*.[8] In *Seabrook*, the Commission defined prudence as the "course of conduct that a capably managed utility would have followed in light of existing and reasonably knowable circumstances."[9] The foundation of the prudence standard is the Commission's statutory duty to establish just and reasonable rates. In examining prudence, the Commission must consider whether a utility is operating as efficiently as possible and using sound management practices.[10]

In *Seabrook*, the Commission laid out the following factors to consider in determining whether the utility has acted prudently:

> 1. Senior utility executives are expected to possess a high degree of financial and technical expertise.
>
> 2. While the prevailing practice of the utility industry is relevant, it is not determinative. The decisions of utility executives must also be reasonable when viewed against the decisions and courses of conduct of other corporations that make investment decisions of a comparable size and complexity. . . .
>
> 3. The size and nature of the undertaking being reviewed must also be considered. . . .
>
> 4. Review of utility decisions should consider the utility's legal obligation to provide . . . safe, reasonable and adequate service at the lowest possible cost over time throughout its service territory and to operate "as efficiently as possible" using "sound management practices." 35-A M.R.S. § 51 [now section 301 of Title 35-A]. A utility is not free to tailor its decisions to profit maximization to the degree that an unregulated company would. . . .

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8 *Public Utilities Commission, Investigation of Seabrook Involvements by Maine Utilities*, Docket No. 84-113 (Phase II) Order (May 28, 1985) ("*Seabrook*").

9 *Id.* at 12.

10 35-A M.R.S. § 301(2), (4); *Maine Public Utilities Commission, Investigation into the Annual Reconciliation of CMP's Stranded Cost Revenue Requirements and Costs*, Docket No. 2006-200, Order at 9 (Mar. 24, 2008).

> 5. A review of prudency requires an examination not only of the initial investment decision but also of the continuing action of the utilit[y] in response to changing circumstances.
>
> 6. If a utility has selected from among several reasonable courses of action[,] one [of] which turns out badly, the utility's decision was not imprudent.
>
> 7. The utility's course of conduct must be reviewed in light of existing facts and circumstances that either were known or knowable through an effort consistent with the size of the risk at the time decisions were made . . . [and] cannot be defined by hindsight.[11]

If the Commission finds imprudence, it must determine whether the imprudent action harmed ratepayers. If it did, then the injury or damage from that action must be quantified.[12]

As "the party adverse to the [C]ommission," Northern bears the general burden of proof in this case, including on the question of prudence.[13] "[I]in the absence of a showing of inefficiency or improvidence," the Commission will not substitute its judgment for that of utility managers.[14] Yet there is no presumption of prudency when the issue arises in a proceeding.[15] Once a party or the Commission Staff has raised the issue of inefficiency or imprudence "in a sufficiently specific way," the party or Staff has met its burden of production, and the burden then shifts back to the utility to demonstrate that its actions were prudent.[16]

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11 *Seabrook*, *supra* note 8, at 12–13.

12 *Id.* at 13–14.

13 35-A M.R.S. § 1314(1), (2).

14 *Cent. Me. Power Co. v. Pub. Utils. Comm'n*, 153 Me. 228, 243 (1957); *see also Seabrook*, *supra* note 8, at 9.

15 *Central Maine Power Company, Application for Fuel Cost Adjustment Pursuant to Chapter 34 and Establishment of Short-Term Energy Only Rates for Small Power Producers Less Than 1 MW Pursuant to Chapter 36 (Investigation of QF Contracts)*, Docket No. 92-102, Order at 12 (Oct. 28, 1993) (rejecting the argument that a presumption of prudency exists, and clarifying that only "[i]n the absence of *any* challenge [will] the utility's actions . . . be presumed to be reasonable" (emphasis in original)).

16 *Central Maine Power Co., Annual Price Change Pursuant to Alternative Rate Plan (ARP* 2008), Docket No. 2011-77, Order at 19 (July 27, 2012); *Central Maine Power Company, Application for Fuel Cost Adjustment Pursuant to Chapter 34 and Establishment of Short-Term Energy Only Rates for Small Power Producers Less Than 1 MW Pursuant to Chapter 36 (Investigation of QF Contracts)*, Docket No. 92-102, Order at 13 (Oct. 28, 1993).

IV. ISSUES NOT IN DISPUTE

Before reaching the disputed issues in the case, the Commission addresses several aspects of Northern's revenue requirement about which there is no dispute.

A. Prior Rate-Case Expenses

In its initial filing, Northern normalized rate-case expenses to include in the revenue requirement but also included $17,021 for the amortization of costs from its previous rate case (Docket No. 2017-00065). Both the OPA and Commission Staff took exception to this proposed treatment. Northern agreed that it was not appropriate to include amounts from the previous rate case when the Commission's policy is to normalize rate-case expenses. In its rebuttal filing, Northern removed this amount from its revenue requirement.

As Northern has adjusted its revenue requirement to remove these costs, no other adjustment for prior rate-case expenses is necessary.

B. Payroll Increase

In its initial filing, Northern calculated the adjustment to the test-year payroll expense by annualizing payroll expenses for the test year, reflecting payroll increases that occurred during 2019, and estimating projected payroll increases for 2020 assuming the same percentage increase granted in 2019 would be granted in 2020. The OPA objected to the use of the 2019 rate increases for 2020 for the non-union employees as Northern's rate increases were not certain. In its rebuttal testimony, Northern adjusted the proposed pay increases to reflect actual 2020 rate increases. In its brief, the OPA accepted the use of the actual January 2020 payroll increases. OPA Br. at 4.

As the OPA has accepted the adjustment in Northern's rebuttal testimony, no other adjustment to the revenue requirement is necessary.

C. Property Taxes

In its initial filing, Northern adjusted its test-year property taxes to project its 2020 annualized property tax expense. Northern then computed its increase in property taxes based on a three-year compound growth rate. The OPA disagreed with the adjustment for the growth rate. In its rebuttal, Northern revised its property tax expense to reflect the actual property tax bills. In its brief, the OPA accepted Northern's proposed property tax expense. *Id.* at 9.

As the OPA has accepted the adjustment in Northern's rebuttal testimony, no other adjustment to the revenue requirement is necessary.

D. Legacy Customer Information System

The OPA in its direct testimony recommended that the $10,200 expense for the vendor support contract for Northern's legacy customer information system be removed from the cost of service because the contract will expire and no longer be needed. In its rebuttal testimony, Northern agreed that the expense should be removed but noted that the amount allocated to Northern was only $2,290. In its brief, the OPA accepted $2,290 as the proper adjustment. *Id.* at 12.

As the OPA has accepted the adjustment in Northern's rebuttal testimony, no other adjustment to the revenue requirement is necessary.

E. Retirement Costs

In its January 15, 2020 update, Northern included actual 2020 calendar-year expenses for pensions, post-retirement benefits other than pension (PBOP), and supplemental executive retirement plans (SERP). In its brief, the OPA agreed with Northern's adjustment for these retirement costs because the adjustment was based on the actual costs Northern was to incur. *Id.* at 7.

As the OPA has accepted the adjustment in Northern's update, no other adjustment to the revenue requirement is necessary.

F. Rate-Case Expenses

There was ultimately no dispute between the OPA and the Company concerning the regulatory proceeding expenses Northern incurred in pursuing this rate case and the period for normalizing them (three years). In its brief, the OPA argued that the Commission should not approve these expenses without documentation supporting the costs. The Examiners' Report did not address this issue and it was not raised in exceptions. Because these costs are normalized rather than amortized (i.e., full recovery is not guaranteed), the Commission does not at this time require Northern to file that supporting documentation, though it may require such documentation in future cases.

G. Other

The Company's proposed revenue requirement included a number of other elements that were the subject of little to no questioning and no dispute. The Commission accepts the parties' lack of dispute on those elements of the revenue requirement and thus approves them. As with any settled result, our approval of these agreed-upon elements of the revenue requirement does not serve as precedent for approving the same items in the future.

The disputed elements of Northern's case are addressed in the sections that follow.

V. REVENUE REQUIREMENT

A. O&M Expenses

1. Residual O&M Expenses

a. Description

Northern proposed an increase of $122,594 to what it calls "residual" operations and maintenance (O&M) expenses. Northern Br. at 33. Residual O&M expenses are costs for which the Company has not made a discrete adjustment to the amount of expense in the test year, but instead proposed to adjust by applying a compound annual growth rate. Here, Northern's revenue-requirement model does not provide a line-item breakdown of costs within this category. Northern explained in its direct testimony that this category includes expenses such as: fuel for its fleet of utility vehicles; professional fees such as actuarial, audit, and legal services; office supplies; telecommunication expenses; natural gas for heating; cleaning and building maintenance; snow removal; and other contractor services. Rev. Req. Dir. at 21–22. In its rebuttal, Northern added that severance expense is captured in this category. Rev. Req. Reb. at 10; *see also* Sched. RevReq-3-15, line 18 (Rev. Jan. 15, 2020).

b. Positions of the Parties

i. The Company

In support of its adjustment, the Company argued that it is not feasible to determine specific adjustments for residual O&M expenses, but that the expenses are still subject to inflationary pressures. Northern stated that the primary purpose of this adjustment is to better match operating costs with the level of costs the Company will experience during the rate year and to mitigate residual expense-related earnings deficiencies. Northern Br. at 34. According to Northern, this adjustment is sufficiently known and measurable because it is calculated based on the Company's actual observed increase in residual expenses from 2016 to 2018 rather than forecasted inflation, and is therefore not contrary to the Commission's decision in Docket No. 2017-00065 in which a similar adjustment calculated based on inflation was disallowed. *Id*.

ii. The OPA

The OPA argued that Northern's adjustment to residual O&M ought to be rejected. In the OPA's view, the proposed adjustment is, in essence, an inflation adjustment characterized as a compound growth rate and, thus, consistent with the Commission's decision in Docket No. 2017-00065, it is not known and measurable and should not be allowed. OPA Reply Br. at 11. The OPA also observed that the Company's calculation of the growth rate partially reflects management's decisions and, as a result, management decisions from year to year can influence the actual growth rate, apparently creating an opportunity for the Company to manipulate that rate. OPA Br. at 11.

iii. Staff

In the Bench Analysis, Staff recommended disallowing the proposed residual O&M adjustment. Staff observed that in this case, as in the last rate case, the Company calculated its revenue requirement based on its historic test year adjusted for known and measurable changes, rather than on a full attrition analysis that would have included a forecast of rate-year sales and expenses. BA at 4. Staff acknowledged that expenses are often subject to inflationary pressures but argued that that notion does not mean certain costs will follow historic trends in a known and measurable way. *Id*. at 4–5.

c. Discussion and Decision

In rejecting the Company's proposed inflation adjustment to residual O&M expenses in the Company's last rate case, the Commission stated that it

> has in the past distinguished adjustments made as part of an attrition analysis [from] known and measurable adjustments to the test year. An attrition analysis is largely based on forecasts and, by its nature, involves a lesser degree of certainty. In contrast, when making test year adjustments, the Commission has applied a strict known and measurable standard. Specifically, to be "known," the change to the test year must be reasonably certain as to whether and when it will occur and to be considered "measurable," the amount of the change must be reasonably certain.

Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change, Docket No. 2017-00065, Order (Corrected) at 31–32 (Feb. 28, 2018) (internal citations omitted).

In this case, the Company has again proposed that its rates be based on the test year adjusted for known and measurable changes, rather than based on a rate-effective-year attrition analysis which would look at forecasts of both expenses and revenues. The fact that operating expenses generally increase over time does not, in and of itself, satisfy the known and measurable standard. The Commission is not persuaded by the Company's argument that calculating the adjustment using a compound annual growth rate is materially more precise than using an inflation forecast.

The problem is magnified by the fact that the Commission may not have the full list of expenses that are included in the catchall of "residual O&M expenses." For example, only in rebuttal did the Company explain that severance expenses were included in residual O&M expenses, rather than, say, payroll or as a standalone category.

Along these lines, it is not obvious to the Commission that every type of expense within the residual O&M expenses has a relationship to a compound annual growth rate or similar kind of cost inflator. For example, the amount of the Company's severance expenses is case-specific and circumstantial. The information the Company provided on its history of severance expense[17] shows that that amount varies significantly from year to year depending on situations that are probably unpredictable, rather than following a predictable economic pattern. It is possible that there are other cost elements within residual O&M expenses that similarly are not subject to the kind of inflationary pressures that, say, cleaning and building maintenance might be.

The Commission thus concludes that the Company’s proposed adjustment for residential O&M expenses fails to qualify as a known and measurable change to test- year expenses and disallows the proposed $122,594 increase to these expenses.

2. Severance Payments

a. Positions of the Parties and Staff

i. Northern

In 2017, Unitil Service Company (USC) made severance payments of $38,017 and, in 2018, USC made severance payments of $255,760, of which $56,393 was allocated to Northern. Northern capitalized $18,571 of these payments, which left $37,722 in the revenue requirement. OPA-002-012, Att. 1.

In its rebuttal, Northern provided three years of severance expense at USC. Rev. Req. Reb. Exh. CGDM-2. Northern argued that this information showed that the severance expense in the test year was similar to the average severance expense incurred annually from 2016 to 2018. Rev. Req. Reb. at 9; Northern Br. at 28. Northern also indicated that no adjustment to payroll was necessary as the severance expense was incurred at the USC level and was excluded from the payroll amounts. Northern stated that the severance expense was instead included as part of the residual O&M expense adjustment on Schedule RevReq-3-15 based on the residual compound annual growth rate. Rev. Req. Reb. at 9–10.

ii. OPA

In its direct testimony, the OPA recommended removing severance costs from the cost of service because they are not expected to be incurred during the rate- effective period. The OPA argued that the severance payments were based on the continuation of each employee’s base pay. In its brief, the OPA pressed this issue further, suggesting that it was questionable whether the severance related to certain of the individuals should be recovered due to the relationship to the [**BEGIN CONFIDENTIAL**] **
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*** [**END CONFIDENTIAL**] OPA Br. at 6. The OPA thus recommended reducing operating expenses by $37,722 and payroll taxes by $2,886. Morgan Dir. at 9.

17 Northern provided its annual severance payments in response to EXM-014-004 and EXM-014-005.

The OPA also argued that the analysis in Rebuttal Exhibit CGDM-2 is logically flawed because including the higher 2018 amount in the calculation means including the test year in a calculation of what adjustment should be made to the test year. OPA Br. at 5.

iii. Staff

In its Bench Analysis, Staff agreed with the OPA that the severance payments should not be included in Northern's revenue requirement because they were not expected to be incurred during the rate-effective period. The Staff added that even if USC incurs severance payments regularly, the 2018 severance payment was likely not representative due to one of the employees being a high-earning employee. The Staff's view was that the record did not establish a trend or pattern of payments supporting the level of severance benefits as indicative of normal years. In addition to reducing the payroll and payroll taxes by $37,722 and $2,886, respectively, Staff recommended that these amounts be removed from payroll prior to applying the payroll growth rate to determine the revenue requirement for the rate year. BA at 6–7.

b. Discussion and Decision

The Commission agrees with Northern that severance payments should be included in Northern's revenue requirement. USC has made severance payments in each of the years for which the Commission has information, 2010 through 2019.[18] The Commission does not, however, agree that the amount Northern included in its revenue requirement calculation—$37,722—is the appropriate level to be included in the revenue requirement. As shown in the table below, the test-year level upon which this value was based was the highest level of severance expense out of the 10 years for which the Commission has information:

Figure 1: Annual Severance Expense, 2010–2019[19]

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 (TY)**	**2019**
USC Total	$215,176	$66,125	$33,215	$63,065	$7,978	$8,365	$190,000	$242,766	$255,760	$116,377
In Northern's Rev. Req.	$ 26,194	$ 8,367	$ 3,809	$ 7,275	$1,029	$1,133	$ 27,689	$ 34,949	$ 37,722	$ 17,382

Average 2016–2018: $33,453
Average 2010–2019: $16,555

18 EXM-014-004; EXM-014-005; Rev. Req. Reb. Exh. CGDM-2.
19 EXM-014-004; EXM-014-005.

The Commission does not agree with Northern’s assertion that the 2018 test year is indicative of a normal level of severance expense for the Company. Northern Br. at 28. While the severance expense in 2018 was of a similar magnitude to the average of the 2016 through 2018 period of $33,453, Northern Br. at 28, the average of the 2016–2018 period is more than double the average of the whole period for which we have data (2010–2019) of $16,555. Moreover, [**BEGIN CONFIDENTIAL**] ** ** ** [**END CONFIDENTIAL**][20] In addition, the more recent 2019 level of severance was less than half the 2018 value. Therefore, it appears that the severance expense over the period 2016 through 2018 is not representative of a normal level of severance expense. The Commission thus finds that the average severance expense over the period for which we have information (2010–2019) of $16,555 should be used as a normal level of severance expense in the revenue requirement. Therefore, an adjustment of $21,167 must be made to the test year residual O&M expense to reflect this average severance expense amount.

3. Medical Costs

Unitil, and Northern as one of its subsidiaries, provides its employees medical benefits and self-funds those benefits. Northern adjusted its test-year expense for estimated increases for 2019 and 2020, resulting in the inclusion in the revenue requirement of $252,907 for medical costs. The OPA disagreed with Northern’s adjustment.

a. Positions of the Parties

In the Bench Analysis, the Staff did not take a position on Northern’s medical expenses. The Company’s and the OPA’s positions on this issue can be summarized as follows.

i. The Company

Northern’s initial filing included an adjustment to increase test-year medical insurance costs based on actual working rates[21] for 2019 and estimated rates of 8% for 2020. Northern stated that it would update the adjustment to reflect actual working rates for 2020 before the completion of this proceeding. Rev. Req. Dir. at 18. In its rebuttal testimony, Northern updated its estimated increase for 2020 working rates from 8% to 20% based upon an underwriting analysis from its employee-benefits consultant. Rev. Req. Reb. at 11. In future years, Northern expects the increase to be more typical of industry trends, closer to 9% per year. Northern Br. at 30 (citing Tr. at 135–36 (Jan. 22, 2020 Hr’g); EXM-014-007).

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[20] **[BEGIN CONFIDENTIAL]** *** ** ** ** ** ********************************** [**END CONFIDENTIAL**]

[21] The term “working rates” as used here is discussed at page 20.

In its brief, Northern stated that, like most large employers, Unitil self-funds its employee-benefit plan and consistently take steps to contain healthcare costs. Northern stated that the working rates established each year are equivalent to premiums charged by third-party insurance providers and are the actual rates used to determine employee contributions. Northern added that the working rates were developed using historical claims experience through the application of standard underwriting methods and actuarial tools, and that the working rates determine employee contributions and are correlated to the Company's experience. The Company thus argued that the Commission should accept the adjustment as reasonable for the purposes of establishing rates.[22] Northern Br. at 30–31.

The Company added that the Commission has not addressed the treatment of working rates in the context of an adjustment to test-year expenses and that insurance expenses were accepted without issue in the Company's last rate case, Docket No. 2017-00065. *Id.* at 30.

ii. The OPA

In his direct testimony on behalf of the OPA, Mr. Morgan stated that the escalation rate for 2020 is not known and measurable and should not be used for ratemaking purposes and proposed to eliminate that portion of Northern's medical expense adjustment, reducing those costs by $51,798. Morgan Dir. at 10.

In its brief, the OPA argued that the Company's Rebuttal Exhibit CGDM-3 showing a 20% increase in working rates should be rejected because the data it contains is stale. The OPA argued that Rebuttal Exhibit CGDM-3 is a planning document based only on the participants in the plan through July 2019, and changes in the number of participants could change the per participant cost. The OPA continued to emphasize that the rates used by Northern to calculate the medical costs do not appear to be known and measurable. The OPA thus argued that the Commission should deny the requested 20% increase and reduce the cost of service by $110,734. OPA Br. at 8–9.

In its reply brief, the OPA opined that Northern's argument that the Commission has not previously addressed the issue of working rates and that its insurance expense updates were accepted in the previous rate case does not mean that they should not be examined here. The OPA argued that the issue is not whether the working rates should be used, but rather whether the working rates were determined based upon adequate support and reliable statements. The OPA argued that the Company has essentially claimed that these are their actual rates, and that the Company's own testimony showed that the working rates are not the actual rates. OPA Reply Br. at 10.

22 Schedule RevReq-3-9, Revised on January 15, 2020, shows a test-year adjustment of $252,907. The original adjustment was $186,577, a difference of $66,330, not $67,680 as stated in Northern's brief.

iii. The Company's Response

In its reply brief, Northern asserted that under the OPA's logic only premiums paid to a third-party insurance provider would be deemed known and measurable. According to Northern, the working rates are effectively "premium equivalents" developed by the Company and its employee-benefits consultant to determine the plan costs for the benefit year. Once the rates are set for the year, they do not change, and thus they are known and measurable. The Company argued that disallowing the adjustment for the 2020 working rates would create a disincentive for utilities to adopt and maintain cost-effective policies through self-insurance.

b. Discussion and Decision

In reviewing the positions, the Commission notes first that because Unitil, and therefore Northern, self-funds its medical benefits, the "working rates" are not rates that are paid for insurance but instead are the basis for an estimate of the actual medical costs that Northern will cover for 2020. Northern has shown that the process used to estimate those costs was reasonable and based upon actual historical claims. The Commission thus finds that the total adjustment of $252,907 as shown on Schedule RevReq-3-9 Revised (filed January 15, 2020) to the revenue requirement calculation is acceptable and may be used for ratemaking purposes as a known and measurable adjustment to the test year.

4. CIS Amortization

Northern has capitalized the CIS as an intangible asset. As an intangible asset, Northern records an amortization expense to reflect the write-off of the asset over the asset's expected life. This is roughly the same as recording a depreciation expense for a tangible asset. Northern is amortizing the CIS over 20 years and the Meter Data Management System (MDMS) over 10 years.

a. Positions of the Parties

The Company included $325,245 in amortization expense related to its new CIS based on a total CIS cost of $36.8 million and an allocation factor of 22% to determine Northern's share. CIS Reb. at 28. In its Bench Analysis, the Staff proposed allowing only the original $12.7 million budgeted cost in rate base and that Northern's share be calculated with an allocation factor of 20% based on the revenue and customer factors and excluding the plant factor (see Section V.B.3.iv.b). The Staff made a corresponding adjustment to the Company's test-year amortization expense, proposing a net amortization amount of ($30,891), which reflected removal of $157,891 in amortization related to the MDMS, and inclusion of $127,000 related to the originally budgeted CIS system. Staff noted that, at the time of the Bench Analysis, it was not clear how much of the original budget was related to the MDMS so its proposed adjustment was not precise.

b. Discussion and Decision

In Section V.B.3, below, the Commission decides the appropriate amount of the CIS system to be included in rate base in this case. For the reasons discussed in that section, the Commission finds it appropriate, at this time, to base rates on $12.7 million of the $36.8 million in CIS costs and to use the three-factor allocator, as proposed by Northern, to calculate Northern's share of the CIS costs. Accordingly, the Commission finds that a test-year amortization expense of $(20,199) is the appropriate corresponding CIS amortization cost to be included in the revenue requirement expense calculation. This reflects (1) removal of $156,899 in amortization related to the MDMS,[23] and (2) inclusion of $139,700 related to the approved CIS amount.[24]

B. Rate Base

1. Calculating Rate Base

There is a dispute in this case about whether Northern's revenue requirement should be calculated using average rate base or year-end rate base, and, if year-end rate base is used, what adjustment is appropriate to account for sales growth from those year-end investments.

a. Background

In its last base rate case, the Company calculated its revenue requirement using test-year-end rate base. Both the OPA and the Staff disputed the Company's use of year-end rate base on the ground that it resulted in a mismatch of costs and revenues. The Commission ultimately rejected the Company's position, finding that most of Northern's plant additions were made at year's end, and "a significant part of year-end investments would produce additional revenues." *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 15 (Feb. 28, 2018). The Commission also determined that use of test-year revenues only, "without any adjustment to reflect sales growth associated with the plant added at year-end, would not reflect any of the known and measurable changes related to placing those assets in service and would be contrary to the Commission's holding" in *Bangor Gas Company, L.L.C., Request for Renewal of Multi- Year Rate Plan (35-A M.R.S. § 4706)*, Docket No. 2012-00598 Order at 21–22 (Sept. 8, 2014). *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 15–16 (Feb. 28, 2018).

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23 This amount reflects the correction Northern noted in Exhibit 5 to its exceptions to the Examiners' Report.

24 See Schedule RevReq-3-13 in Staff's workpapers, which were attached to the Bench Analysis. Because it is not clear at this time how much of the allowed $12.7 million is related to the MDMS, the $139,700 amortization amount does not precisely reflect the different amortization periods for the MDMS and CIS components.

b. Positions of the Parties and Staff

i. The Company

In this case, Northern proposed to calculate its revenue requirement using test- year-end rate base—i.e., rate base as of December 31, 2018—with an adjustment of $630,776 to revenues, which was intended to reflect sales growth produced by 2018 year-end investments. Rev. Req. Dir. at 28–29. The Company responded to the Commission's concerns as laid out in Docket No. 2017-00065 by applying an adjustment that "annualized revenues for new customer locations added during 2018" and imputed 2019 annualized revenues for "new customer locations whose initial meter read was in January 2019." Rev. Req. Dir. at 29. Setting aside the adjustment, Northern's 2018 year-end rate base was $226,372,169, compared with a 2017 year-end rate base of $200,004,569. Rev. Req. Dir. Sched. RevReq-5-1 (columns 2 and 6).

In support of using year-end rate base, the Company stated that "year-end rate base better aligns the Company's capital investments at the time new base rates [are to] become effective . . . when compared to using a 13-month average rate base . . . which creates an additional lag in recovery." Rev. Req. Dir. at 29. In support of its adjustment, the Company stated that the adjustments help to "match[] . . . and balance[] with known and measurable changes in sales growth" and to "address[] the revenue matching principle articulated in prior Commission orders." *Id.*

The Company maintained that setting rates using year-end rate base is necessary to counter what it considered to be well-documented earnings erosion or attrition. Northern Br. at 9–10. According to Northern, that attrition is

> due in large part to the Company's ongoing investment in non-growth- producing facilities, including but not limited to replacing and upgrading aging distribution facilities such as cast iron and bare steel infrastructure and farm tap regulators; the relocation, replacement, and abandonment of existing distribution facilities per state and local mandate; and meeting federal and state gas safety regulations.

Northern Br. at 9–10. From 2014 to 2018, Northern invested over $150 million in capital projects to improve the safety of its system and reliably serve its growing customer base, with another $180 million expected to be invested from 2019 to 2023. *Id.* at 10 (citing Ops. Dir. at 7–9, Overview Dir. at 9–10, 12–13; Earnings Dir. at 8–9). With so much investment in non-growth-producing capital projects, the Company claimed that revenues have not kept up with required investments, resulting in an inability for Northern to earn its allowed return.

Putting numbers to the problem, the Company stated that it earned a 7.3% return on equity in 2018, more than 2% lower than its allowed ROE for that year of 9.5%. Rev. Req. Reb. at 22–23. Northern projected that in 2019 it would earn an even lower of 6.6% ROE. *Id.* at 23 (citing Rev. Req. Reb. Sched. CGDM-8). Northern described this as "reflective of a historical trend going back to the Company's 2013 rate case, after which the Company earned its allowed return in the rate effective year but experienced [a] steady and dramatic erosion [in] earnings over subsequent years." *Id.* (citing Rev. Req. Dir. Sched. CGDM-2 and Earnings Dir. at 17, 18–19). Mr. Lyons and Ms. Nelson compared Northern's authorized ROE with its earned ROE in each year from 2014 through 2018, finding that "the Company under-earned its authorized ROE by nearly 220 basis points, on average" annually over that period. Northern Br. at 79 (citing Earnings Dir. at 17, Table 5). The primary cause of this decline in experienced ROE was a decline in asset turnover, "indicating that the Company experienced diminished efficiencies in its assets because increases in revenues did not keep pace with increases in capital expense." Northern Br. at 79 (citing Earnings Dir. at 18–19). According to the Company, it would not be possible to offset the increase in capital expense with savings; "[t]o achieve its allowed return during 2017 through O&M savings, Northern would have had to reduce costs by nearly half." Northern Br. at 79 (citing Earnings Dir. at 23, Fig. 8).[25]

The Company "believes strongly that the use of year-end rate base is appropriate and necessary for the Company to have a reasonable opportunity to earn its allowed return in the rate effective year . . . ." Rev. Req. Reb. at 21–22. Northern cited to several cases in which the Commission approved or, in *dicta*, allowed for the use of year-end rate base, and to decisions of sister jurisdictions where the use of year-end rate base is generally accepted. Northern Br. at 10–12. The Company asserted that using year-end rate base "will not completely mitigate the effect of the attrition and regulatory lag that will occur between the time that the case is filed and the time that rates take effect," but that "it strikes the appropriate balance of setting rates that are based on known and measurable cost, investment levels, actual capital structure of the Company and expenses" and creates an incentive for "the Company to manage costs in between rate cases to have an opportunity to [earn its] . . . allowed return on equity." Rev. Req. Reb. at 22.

ii. Staff

In the Bench Analysis, the Staff expressed disagreement with the Company's use of year-end rate base, even with its proposed adjustment. The Staff pointed out that the Company's use of year-end rate base was contrary to the Commission's longstanding practice of using average rate base to calculate the revenue requirement in litigated base-rate proceedings. *See, e.g.*, *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 15–16 (Feb. 28, 2018); *Bangor Gas Company, L.L.C., Request for Renewal of Multi-Year Rate Plan (35-A M.R.S. § 4706)*, Docket No. 2012-00598, Order (Sept. 8, 2014). At the Commission, "[t]he use of an average year rate base is standard

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[25] As the Commission discusses in Sections V.B.1 and VII, the Company's arguments in favor of year-end rate base are similar or identical to those in favor of adopting the CIRA where those arguments discuss earnings erosion or investments in non-growth-producing investments. While the testimony of Ms. Nelson and Mr. Lyons was generally to support the CIRA, the Company has also used that attrition analysis to support its proposal to calculate the revenue requirement using year-end rate base.

procedure." *Re Cent. Maine Power Co.*, F.C. No. 2168, 15 P.U.R.4th 455 (Sept. 1, 1976). According to the Staff, use of an average rate base is preferable because it is more likely to satisfy the matching principle:

> Since the revenues, operating expenses, and taxes represent the level of operations in the test year, the return should be based on the investment [that] was required to produce that level of operations. The rate-making principle is one of keeping the time and amount of the revenues, the expenses, and the rate base on a consistent basis.

Re Central Maine Power Co., F.C. No. 2168, 15 P.U.R.4th 455 (Sept. 1, 1976).

Along these lines, Staff argued that use of an average rate base would better reflect the fact that "year-end plant in service [is] not fully utilized during the test period. New plant [is] placed in service from [month to month] during the test period and a substantial portion [does] not become used and useful until the last months of the test period." *Re Central Maine Power Co.*, F.C. No. 2168, 12 P.U.R.4th 455 (Me. P.U.C. Sept. 1, 1976) (quoting *Re Nw. Bell Tel. Co.*, 97 P.U.R.3d 444, 452 (Iowa State Comm. Comm'n 1972)). According to Staff, that trend was true for Northern, too. For example, from January to July 2019, the Company added only $2.2 million, or approximately 6%, of its forecasted $36 million in 2019 plant additions. EXM-002-002. And although its test-year-end (2018) rate base was $226,372,169, its five-quarter-average rate base was $206,816,185, and its 13-month-average rate base was just $204,165,737. Staff Hr'g Exh. 6.

The Staff also argued that even though the Commission left open the possibility of using an adjustment to year-end rate base in calculating a utility's revenue requirement,[26] the adjustment the Company proposed was inadequate. The Company's adjustment annualized the revenues from the new-customer premises added during 2018 that would not have been included in the test-year billing determinants. Rev. Req. Dir. at 13. The Company also annualized the revenues for customers whose initial meter reading was in January 2019 and, therefore, were also not included in the test- year billing determinants. *Id*. In the Staff's view, this adjustment did not adequately match sales with year-end investment because it assumed that only customers newly billed in January followed from the substantial year-end investment. The Company added 229 new customers from January to April 2019, and an additional 25, 82, and 38 customers in May, June, and July 2019, respectively. EXM-002-009. Given that the

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26 For example, in Docket No. 2017-00065, the Commission rejected Northern's proposed year- end rate base because there was "no suitable proposal in the record" to match it "with known and measurable revenue increases . . . ." *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 16 (Feb. 28, 2018); *see also Re Central Maine Power Co.*, F.C. No. 2168, 12 P.U.R.4th 455 (Me. P.U.C. Sept. 1, 1976) ("'[A]n end-of-period rate base is improperly matched with test-year revenues and expenses, unless both are adjusted to end-of-period levels for additional customers added and increased usage per customer.'" (quoting *Re Nw. Bell Tel. Co.*, 97 P.U.R.3d 444, 452 (Iowa 1972)).

Company's construction season typically does not begin until mid-April, Tr. at 169 (Aug. 28, 2019 Tech. Conf.), Staff believed it would be reasonable to include annualized revenues from customer additions during the first six months of 2019 to match to year-end 2018 plant. In response to a data request, the Company estimated that its revenue forecast would include an additional $291,146 if per-customer additions through July 1, 2019 were used. EXM-002-014. Staff argued that, if year-end rate base is allowed, the sales forecast should be increased by that amount to better match plant investment with the customer sales resulting from that investment.

iii. The OPA

In testimony, the OPA did not take an express position on the use of year-end versus average rate base but incorporated the Company's adjusted year-end rate base into its revenue-requirement calculation. In its brief, the OPA stated that it "agree[d] with Staff's recommendation," which appeared to mean that the OPA agreed with the "addition of $291,146 in revenues" if year-end rate base were used. OPA Br. at 13. The OPA did not take a clear position on the use (or not) of average rate base. *See* OPA Br. at 12–13.

c. Discussion and Decision

On the calculation of rate base, there are two main questions before the Commission: (1) whether to use year-end rate base or average rate base to calculate Northern's revenue requirement, and (2) if using year-end rate base, whether and by how much to adjust revenues to reflect that investment. For the reasons that follow, the Commission approves the use of year-end rate base with the adjustment to revenues that the Staff proposed and the OPA supported.

i. Year-End Versus Average Rate Base

a. Description of the Options Available to the Commission

There is a wide disparity between the two main options available to the Commission in calculating rate base. First is average rate base—a number that is consistent with "standard procedure"[27] for the Commission but is far below the actual plant in service by the end of the test year and when rates will go into effect in this case. Second is year-end rate base (with some adjustment)—a number that is far more proximate to the plant in service for the rate-effective period but that is also far above the average rate base the Commission would typically apply in a historic-test-year rate case. The following table illustrates the difference between these two amounts for Northern:

Figure 2: Comparisons of Month-End Rate Base with Quarter-End and Average Rate Base with Year-End[28]

Month or Quarter Ending	Rate Base (by Month)	Rate Base (by Quarter)
December 2017	$200,353,505	$200,353,505
January 2018	$201,110,413	
February 2018	$200,287,761	
March 2018	$202,004,569	$202,004,569
April 2018	$203,385,044	
May 2018	$202,914,444	
June 2018	$202,240,482	$202,240,482
July 2018	$203,321,529	
August 2018	$202,829,665	
September 2018	$203,110,211	$203,110,211
October 2018	$202,762,762	
November 2018	$203,462,003	
December 2018	$226,372,169	$226,372,169
Average	**$204,165,737**	**$206,816,185**
Year-End (without adjustment)	**$226,372,169**	

The reason for the large disparity is that so little plant is added to rate base throughout the year; in Northern's case, as Figure 2 shows, nearly all of the net plant added to rate base during the year is added in December, the final month of the year. This lopsided accounting of rate base results in a 13-month or five-quarter average that is skewed relatively low—to such a degree that the average is very close to the amount in rate base in all of the months *other than* December.

The determination of which calculation of rate base to adopt for the revenue requirement is within the Commission's discretion. In historic-test-year rate cases (such as this one), the Commission's decisions have typically held to the use of average rate base. *See, e.g., Bangor Gas Co., L.L.C., Request for Approval of Renewal of Multiyear Rate Plan (35-A M.R.S. § 4706)*, Docket No. 2012-00598, Order at 21–22 (Sept. 8, 2014) (applying average rate base given absence of appropriate adjustment for sales growth to year end rate base); *Re Bangor Hydro-Electric Co.*, Docket No. 93-062 (Mar. 16, 1994); *In re Millinocket Water Co.*, Docket No. 84-195, 70 P.U.R.4th 387, 395 (Sept. 26, 1985). But there are exceptions to this general rule. For example, the Commission has allowed the revenue requirement to be calculated based on year-end rate base

27 *Re Cent. Maine Power Co.*, F.C. No. 2168, 15 P.U.R.4th 455 (Sept. 1, 1976).
28 Staff Hr'g Exh. 6 (Rev. Req. Dir. Sched. RevReq-5-1 & Rev. Req. Reb. Sched. RevReq-5-1 Revised).

when a Company makes a showing that it has been harmed by attrition or regulatory lag. *See Me. Water Co. v. Pub. Utils. Comm'n*, 388 A.2d 493, 498 (Me. 1978) (finding that use of year-end rate base is a permissible way to address regulatory lag and attrition). Attrition is "the erosion in the rate of return on rate base resulting from an expectation that net operating expenses or net investment in plant, or both, will increase more rapidly than revenues." *Pub. Advocate v. Pub. Utils. Comm'n*, 655 A.2d 1251, 1252 n.1 (Me. 1995) (quoting *New England Tel. & Tel. Co. v. Pub. Utils. Comm'n*, 448 A.2d 272, 311 (Me. 1982)). Regulatory lag is the loss of earnings that occurs between the time a utility files for a rate increase and the date when the new rates actually become effective. *Me. Water Co. v. Pub. Utils. Comm'n*, 388 A.2d 493, 497 (Me. 1978).

Also, in recent cases the Commission has left the door open to the use of year- end rate base, holding that if year-end rate base is used, "the revenue requirement should also reflect any associated sales growth." *Bangor Gas Company, L.L.C., Request for Renewal of Multi-Year Rate Plan (35-A M.R.S. § 4706)*, Docket No. 2012-00598 Order at 21–22 (Sept. 8, 2014); *see also Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 15–16 (Feb. 28, 2018) (leaving open the option of using year-end rate base if an appropriate adjustment is made for revenues from those investments). Here, Northern has offered a way to calculate that adjustment, and (assuming the Commission accepted the use of year-end rate base) the Staff has accepted that adjustment and proposed adding to it to account for growth from sales to customers newly billed in the first half of 2019.

b. <u>Findings on Attrition</u>

The Commission finds that Northern has met its burden of proof to show that it has experienced earnings attrition and that this attrition has grown in recent years. Northern has made significant investments to improve the safety and reliability of its distribution system and, unfortunately, the level of those investments has exceeded the rate of growth in revenues. This has led to a trend of decreasing earnings over recent years—a trend which does not at this time show signs of abating. It is within the Commission's discretion to approve the use of year-end rate base to address this attrition.

Northern also claimed that this trend would continue in future years. The Commission makes no judgment about future trends in earnings. In future rate cases, the Commission will look closely at Northern's investments for reasonableness and will adopt the calculation of rate base that is most appropriate in those future circumstances.

If part of the reason for Northern's erosion in earnings is regulatory lag, an adjustment to address that is also within the Commission's discretion (and might be the same adjustment to address the attrition). It is true that regulatory lag is a fact of life for a utility, "a known condition" that all utilities face. Tr. at 170 (Jan. 22, 2020 Hr'g). For that reason, regulatory lag alone is not a compelling reason for the Commission to make an exception to account for it. But here, where the Company has made a showing of earnings attrition, an adjustment can address both the attrition and any related regulatory lag.

Although it may be simply a matter of semantics, Northern's occasional claim that a significant amount of its investments are "non-revenue-producing" appears problematic on their face. Once added to rate base and recognized in a rate proceeding, the Company does earn revenue (a return) on capital investments. Nevertheless, the Commission understands that in using the phrases "non-revenue-producing" or "non-growth-producing" Northern was arguing that its capital investments in safety and infrastructure are often not directly tied to incremental new revenues or growth (i.e., a pipe serving a new customer).

c. Approval of the Use of Year-End Rate Base in This Case

Having found that the Company has met its burden to show meaningful attrition in its earnings—a showing that was not countered with analysis from any party—the Commission approves the use of year-end rate base (with an adjustment to revenues for sales growth) in this case as a way of addressing that condition. While the use of average rate base is standard practice, there is precedent for the Commission to use year-end rate base given a showing of attrition. As explained above, the Commission has also, as recently as Northern's last rate case, left open the option of using of year-end rate base so long as a sufficient adjustment is made to account for sales growth.

In this case, the Staff at times appeared to take the position that year-end rate base would not be appropriate unless Northern filed a full attrition analysis. Indeed, certain elements of Northern's case where the Company proposes prospective rate-effective-year adjustments for inflation or a compound annual growth rate are typical of an attrition analysis. And use of year-end rate base without any adjustment for sales growth would be contrary to ratemaking principles designed to match investments with revenues, with one piece of the puzzle (rate base) reflecting an investment without a corresponding connection to another piece of the puzzle (revenues) associated with that investment. Throughout this decision, the Commission has attempted to hold to the ratemaking principles associated with historic-test-year cases (test year adjusted for known and measurable changes). Given the Commission's discretion to approve use of year-end rate base in a historical-test-year case, a utility need not file a full attrition analysis for the Commission to do so.

The Commission emphasizes, though, that the use of year-end rate base in this case does not mean that the Commission will approve the use of year-end rate base in Northern's future rate cases or even its next rate case. Every petition for a rate increase will be considered on its own merits under the facts and circumstances presented.

The Company's arguments for using year-end rate base are nearly indistinguishable from those for approving the capital investment recovery adjustment, or CIRA. In support of both items, the Company argued that it has faced increasing erosion in its earnings due to the need to make significant safety-related, government-mandated, or other non-growth-producing investments in its infrastructure. These conditions have led Northern to propose both that its revenue requirement needs to be adjusted to help correct for this attrition (i.e., year-end rate base should be used) and that it needs a capital tracker (the CIRA) to allow it a faster return on certain mandatory investments. Although we have found that Northern has adequately shown it has experienced a trend of earnings attrition, we are rejecting the CIRA, for the reasons discussed below in Section VII.C. The Commission expects that the use of year-end rate base in calculating the revenue requirement in this case will address the earnings problem Northern has raised without the need to resort to alternative ratemaking mechanisms for everyday utility costs. In rejecting the CIRA (Section VII.C, below), the Commission holds that it would not be prudent to approve both of these changes—that is, the CIRA and year-end rate base—as a way to combat earnings erosion. Instead, an incremental approach is preferable and more in line with the public interest. The Company already benefits from annual rate increases under the targeted infrastructure replacement adjustment, or TIRA, and the addition of year-end rate base to the revenue requirement creates another opening for the Company to improve upon its earnings in the coming months and years.

Now that the Commission has approved the use of year-end rate base with an adjustment for sales growth, we turn to considering what adjustment is most appropriate.

ii. Adjustment to Year-End Rate Base

The Commission appreciates Northern's proposed adjustment to year-end rate base, and finds that it presents a good starting point for establishing the right adjustment. But the Commission agrees with the OPA and the Staff that Northern's adjustment is insufficient because it does not account for the revenues that will accrue to the Company from all investments in rate base as of the end of 2018. As part of calculating its adjustment, the Company annualized revenues for customers who received their first meter-read in January 2019. The Staff argued (and the OPA agreed) that revenues should also be annualized for customers who received their first meter-read any time in the first half of the year. Northern's witnesses explained that municipal digging moratoria prevent it from laying pipe through at least April 15 in any given year. EXM-014-002. That means that any customer newly billed at least through the end of April would be receiving service from plant added to the Company's system in the prior year. Tr. at 123–24 (Jan. 22, 2020 Hr'g). The Company's witnesses testified that some service pipes are in construction work in progress (CWIP)—and thus not in rate base—at year's end even if they are in use or ready to be used, Tr. at 124 (Jan. 22, 2020 Hr'g). Even if true, rates simply are not set based on CWIP but instead are set based on plant in rate base.

We find the adjustment the Staff proposed, and which the OPA supported, to be reasonable. It is supported by the fact that Northern's plant in rate base changes so little throughout the year—with just 6% of it added in the first six months of the year—and that digging moratoria prevent new pipe from being installed from late fall through mid-spring in any given year. Because these adjustments are in part based on estimates, any adjustment to year-end rate base is likely to suffer from some level of imprecision. Absent a full attrition analysis—which would forecast critical elements of the revenue requirement (including rate base, revenues, and other items) to the rate-effective year— the Commission and the parties have to accept a certain degree of imperfection. With the information available to it, the Commission finds this adjustment to be reasonable and adequate, and to lead to just and reasonable rates. We thus approve the combination of Northern's proposed $630,776 adjustment and the Staff's additional $291,146 adjustment to revenues for sales growth to balance the incorporation in the revenue requirement of year-end rate base.

2. Cash Working Capital

a. Positions of the Parties and Staff

The Company proposed to include cash working capital (CWC) in the amount of $2,975,676 in rate base. Northern Br. at 24. This is calculated by applying a 46.06-day lead-lag factor, determined in the Company's last rate case, to the test-year operating expenses. OPA witness Mr. Morgan testified that he did not object to using the results of the lead-lag study from the last rate case but argued that it would be more precise to apply the lead-lag days specific to each category or expenses rather than the overall average 46.06-day factor. Morgan Dir. at 7. In the Bench Analysis, Staff agreed that it was reasonable to use the results of the recently completed lead-lag study and agreed with Mr. Morgan's position that it is preferable to apply the results as precisely as possible. BA at 31. Staff observed, however, that it was unclear whether the difference between the Company's and OPA's recommended CWC amount was a result of applying a different calculation or because the two parties applied the lead-lag results to different amounts of operating expense. *Id*. Staff requested that in its rebuttal testimony the Company provide the calculation of the CWC allowance using its method as well as that proposed by Mr. Morgan. Northern complied with this request and calculated a CWC allowance of $2,990,929 using the OPA's method versus the Company's $2,932,022, based on the Company's direct case.

Northern argued that its proposed calculation is correct and consistent with the calculation used in Docket No. 2017-00065, notwithstanding the fact that it results in a lower CWC allowance than that calculated using the OPA's method. Northern Br. at 25–26. Mr. Morgan did not file rebuttal testimony, and in its brief the OPA advocated only that the CWC allowance ought to be adjusted as necessary for other adjustments to expenses and taxes. OPA Br. at 3.

b. Discussion and Decision

There is no dispute among the parties that it is reasonable to use the result of the lead-lag study in Docket No. 2017-00065 to determine the CWC allowance in this case. The Commission agrees. Although not explicitly, the OPA appears to now accept the Company's method for applying the results from Docket No. 2017-00065 to calculate the CWC allowance in this case. Given the apparent agreement, and the fact that the different methods yield only a small difference in the calculated amount, the Commission accepts Northern's method. After adjusting as necessary for the other findings in this order, a CWC allowance of $2,924,866 is included in the rate base.

3. Implementation of New Customer Information System

Over the July 4th weekend of 2017, Unitil performed the cutover from its twenty-plus-year-old legacy billing system to its new customer information system (CIS). Over the previous five years, Unitil Service Company (USC) developed the CIS to serve the needs of the regulated utilities owned by Unitil that operate in Maine (i.e. Northern), New Hampshire, and Massachusetts. These include both electric and gas utilities. In addition to serving multiple jurisdictions, the project included a new MDMS, a new customer portal, and 34 individual sub-system interfaces. CIS Dir. at 8. The July 2017 cutover, or "go-live", went very smoothly and resulted in no customer complaints to this Commission or to the New Hampshire or Massachusetts regulators. CIS Dir. at 42. According to Northern, the new CIS has been performing as intended since it went live. *Id*. at 41–43.

Northern seeks approval to place in its rate base 22% of the final $36,832,636 cost of the system, or $7,765,001. CIS Dir. at 39–40; Ex. BEL-1, Att. B at 1. This allocation to Maine customers is based upon a three-factor allocator "pursuant to Unitil's Cost Allocation Manual as approved by the Commission." CIS Reb at 28.

a. Background of the CIS Project and Allocation Factor

In early 2012, Unitil began the process of developing a replacement for its legacy customer information and billing system, known as SunGuard or HTE. This system had been in place since the mid-1990s and was considered by Unitil to be functionally obsolete. CIS Dir. at 19. Moreover, HTE's vendor, SunGuard, declared in 2010 that the application had reached "end of life," meaning that SunGuard would soon cease providing support for the system. *Id*. at 22. Northern developed a CIS project team that included a Steering Committee and a Working Group that reported to that Committee. Northern Br. at 97. This team developed and described a variety of functions that HTE could no longer perform adequately.

Unitil employed the firm of Black & Veatch, a company that it says was familiar with CIS implementations in the utility industry, to assist with identifying the scope of the project and its key objectives. These included modernizing the "meter to cash" system, improving customer engagement, customer service and data processing/management. CIS Dir. at 24; Tr. at 36 (Aug. 29, 2019 Tech. Conf.). The new system would ultimately be designed to interface with over 30 other software platforms and had to serve the needs of Unitil's regulated gas and electric utilities in three states. CIS Dir. at 8. Unitil also developed a new MDMS to interface with the information sent from the meters and also provide certain analytical information to the CIS. Tr. at 61 (Jan. 22, 2020 Hr'g).

Black & Veatch helped Unitil develop a 120-page request for proposals (RFP) for the vendor of the new CIS. This document provided bidders with "detailed system specifications, testing criteria and more than 50 pages of functional requirements."

Northern Br. at 98. It was ultimately distributed to fifteen CIS vendors and two MDMS vendors in late May 2012. Nine responses were received and, again with the help of Black & Veatch, Unitil narrowed this list to three finalists that were vetted through on-site visits, reference checks and follow-up meetings. *Id*. at 99. Unitil ultimately selected Systems & Software (S&S), a subsidiary of Harris Computers, to develop and implement a new CIS using S&S's software product known as enQuesta. S&S was considered a good choice because it was based in New England and would be "a nimble, responsive and dedicated partner." CIS Dir. at 26. Unitil's contract with S&S was signed in May 2013. ODR-002-015.

At a high level, the project consisted of two distinct parts: the CIS, which covered billing, customer facing applications, and numerous information functions, and the MDMS. The MDMS vendor was an affiliate of S&S called SmartWorks that provided a product called MeterSense. Tr. at 95 (Aug. 29, 2019 Tech. Conf.). The MDMS was completed in May 2016. In April 2018, the MDMS was approved for ratemaking treatment in New Hampshire. CIS Reb. at 30.

S&S began its work with the initiation phase of the project in mid-April 2013. This phase was uneventful and short, ending in June of that year when the second phase— design—began. CIS Dir. at 27–28. This work included a short discovery period followed by a much longer Business Process Analysis period which produced "approximately 70 business process and requirement documents" that became the basis for the following phases up to and including the decision to go live. *Id*. at 28.

Problems began to appear in the first year of implementation. EXM-005-011; Tr. at 74 (Aug. 29, 2019 Tech. Conf.). Between July 2013 and the fall of 2014, the schedule slipped significantly. Both the design phase and the development phase of the project, initially slated to last eight months and five months, respectively, took twice as long as expected. CIS Reb. Exh. BEL-5(B). In March 2015, because of schedule delays, Unitil asked Grant Thornton, an accounting firm with which Unitil had worked for many years, to help review the project.[29] CIS Dir. at 28; Tr. at 69 (Aug. 29, 2019 Tech. Conf.). As a result of this mid-course review, USC took over project implementation with ongoing help from Grant Thornton and refocused the S&S resources away from implementation and toward software development. Grant Thornton was assigned a lead role in system testing management and USC "re-aligned existing resources." Northern Br. at 103; CIS Dir. at 28; CIS Reb. at 15; Tr. at 69 (Aug. 29, 2019 Tech. Conf.). USC and Grant Thornton signed a letter agreement in early September 2015. ODR-002-019, Att. 2.

By the fourth quarter of 2015, USC had completed this change in project management, and had increased the number of resources assigned to the project, including personnel who had experience with Unitil's testing methods. Tr. at 82 (Aug. 29, 2019 Tech. Conf.). Thus, work that began in spring of 2013 with a team of about 60 people developed, in the final two years of implementation, into a much larger team of approximately 200. *Id*. at 80.

29 At this time Grant Thornton had already been involved with the CIS project in an accounting capacity. Tr. at 86 (Jan. 22, 2020 Hearing).

In addition to changing its focus from implementation to software development (which was S&S's core service, CIS Reb. at 15), S&S committed more resources to the project without additional compensation from USC. Northern Br. at 116; *see also* CIS Reb. at 16; EXM-015-007; ODR-002-023 Att. 1; Tr. at 107 (Aug. 29, 2019 Tech. Conf.).

The start of the extensive testing phase coincided with this management realignment. Northern testified that the primary driver of increasing costs after this mid-course review was the amount of testing. Tr. at 67 (Jan. 22, 2020 Hr'g). The original scope included seven months of testing, but after this mid-course change, testing took 21 months. CIS Reb. at 17. Where the initial scope of the project planned for four "data conversions" to be completed over seven months, USC ultimately performed 20 such conversions, which took 21 months. CIS Dir. at 31; *see also* Tr. at 92 (Aug. 29, 2019 Tech. Conf.); Tr. at 66 (Jan. 22, 2020 Hr'g). Witnesses testified that this now meant that 6,000 tests needed to be passed, many of which did not do so at first. By go-live, USC had run 15,000 tests. Tr. at 92 (Aug. 29, 2019 Tech. Conf.). Slides Northern provided for meetings of the project Steering Committee reflect this emphasis on testing. *See, e.g.*, ODR-002-013 Atts. 21–25.[30]

The various phases of testing included functional, integration, business cycle, regression, performance, disaster recovery, and regulatory compliance. CIS Reb. at 17. For this effort, USC asserted that it "committed the necessary resources" and applied its "comprehensive and rigorous" Application Maintenance and Change Control Policy. Northern Br. at 104; CIS Dir. Exh. BEL-3. This increased effort led to increases in the schedule and the costs. CIS Reb. at 17. Mr. Brock testified that testing was performed until all tests were passed, and that this is how management knew when the necessary testing had been completed. Tr. at 32–33 (Jan. 6, 2020 Tech. Conf.). The stated objective of the testing was to "ensure the CIS cutover from the legacy system to new system was seamless to customers and regulators." CIS Reb. at 17.

The time devoted to the go-live phase was close to that originally planned, but USC committed substantially more resources, created "an entirely new team" for support and focused on ensuring that there would be no major incidents during this process. CIS Reb. at 17–18. USC employees were trained to operate and manage the new system and to prepare for contingencies that might arise during and after go-live. *Id*.

Following the July 2017 go-live, USC activated a "bill review" team whose task it was to review every single bill before it was issued by the new system and compare them to invoices issued in June 2017 and in July 2016. This team of 10 or 12 people continued to manually review 100% of post-go-live bills issued in August and

30 No slide presentations to the Steering Committee were prepared after August 2015, with nearly two years to go until go-live, because starting then, the "Steering Committee members were directly involved in the project workflow." ODR-002-013.

September. Tr. at 38 (Jan. 6, 2020 Tech. Conf.). The team fixed any problems it found with bills before the bills were issued. CIS. Reb. at 18; Tr. at 88 (Aug. 29, 2019 Tech. Conf.). Mr. Brock testified that the work performed by this team was “in addition to electronic validation and testing.” Tr. at 39 (Jan. 6, 2020 Tech. Conf.). During the 100 days following go-live, USC kept its entire project staff fully engaged with project work. Tr. at 95 (Aug. 29, 2019 Tech. Conf.). The post-go-live work, originally scheduled for three months, took seven. CIS Reb. Exh. BEL-5(B) at 2.

Northern witnesses testified that following go-live, there were no complaints filed with any of the regulators that oversee Unitil’s subsidiary utilities by any of the customers of these utilities concerning problems with the new CIS. CIS Reb. at 35. They testified that since go-live, the new CIS has reliably been issuing accurate invoices to Maine customers. Northern Br. at 95.

Working with both Black & Veatch and S&S, CIS Reb. at 4, Unitil initially budgeted $12,693,278 for the CIS project. ODR-002-017 Att. 1; BA at 33.[31] Unitil ultimately spent $36,832,636. CIS Dir. Exh. BEL-1, Att. B at 1, 5. Initially, the cutover from the legacy to the new system was planned for the end of March 2015, which would have made it a 23-month project once the contract was signed on May 1, 2013. ODR-002-013 Att. 3 at 3 of 13. Ultimately, work on the project stretched to four and a half years. CIS Dir. at 22, 25, 27, 31; BA at 38.

In 2015, when USC determined that the project was experiencing problems and approached Grant Thornton for assistance, it did not issue an RFP for the services Grant Thornton ultimately provided and did not conduct a formal market analysis before agreeing to the terms. It simply signed a new engagement letter for CIS project management. Tr. at 87 (Jan. 22, 2020 Hr’g). For its work on this project, Grant Thornton was paid $8.1 million, a little less than a quarter of the total CIS costs. ODR-002-018, Att. 1.

To allocate the costs of the CIS project to Northern Utilities and its other subsidiaries, Unitil used its Cost Allocation Manual. EXM-002-044, Att. 1. That manual specifies a three-factor allocation percentage that derives from the revenues, customers, and net plant attributable to each of Unitil’s utility subsidiaries. This resulted in a 22% allocation of the total CIS implementation costs to Northern. Northern therefore requested that $7,765,001 of the $35,295,459 total net plant balance of the new CIS be allocated to Maine and be allowed into Northern’s rate base. CIS Dir. at 39–40.

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31 A slightly larger amount of $13.2 million appears on a different budget document. ODR-002-017 Att. 2. A lower initial estimate of $11.5 million is also in evidence. EXM-005-033, Att. 1.

b. Positions of the Parties and Staff

i. Northern's Position

a. CIS Implementation

Northern argued that its CIS project, like all such projects for regulated utilities, was not an off-the-shelf package, but was complex and unique and thus required all the time, money, and effort that USC devoted to it. The decision of Unitil's management not to rigidly adhere to its initial schedule or budget was reasonable, Northern argued, since doing otherwise would create risks to the final outcome that management was unwilling to accept. Thus, the project went through the mid-course review, leading to more extensive design and testing than originally planned in order to produce results "to the penny." Northern Br. at 109. If the project had been rushed, Northern argued, Unitil might have had to spend "millions" to fix problems and regain the trust of its customers. *Id*. at 110.

Following issuance of the Bench Analysis, including its recommendation of a third-party audit of the implementation, Northern provided testimony and information about decisions management made during implementation. In its brief, Northern divided these issues into three areas of focus: (1) why the CIS tripled in cost from the initial estimate to final product, (2) the hiring of Grant Thornton to assist with implementation, and (3) management's decisions regarding S&S's work on the project.

1. Cost increases. Northern stated that the threefold increase from the initial estimate to the final cost was due to a lack of complete understanding of the needs of the project when the initial estimate and schedule were developed, and then the realization by management that the project was "more complex that initially understood." *Id*. at 101. This realization led to many changes that increased the resources and time devoted to design and testing. Northern stated that testing was the most significant cost, accounting for about 60% of the total. *Id*. at 118.

Northern was "committed to ensuring 100% accuracy through rigorous testing of the new CIS before it was allowed into production." *Id*. According to Northern, aiming for less than 100% accuracy in testing would fail to identify all the bugs and flaws before going live. Unitil was avoiding damage to its reputation that would result from the loss of customer trust. *Id*. at 119. In its brief, Northern cited to the testimony of Mr. Lambert, who said: "we were going to get it right, and, in fact, perfect and achieve the results that we had achieved." *Id*. at 120; Tr. at 102–03 (Jan. 22, 2020 Hr'g). Northern defended the final cost, saying that it was "the cost that was necessary to ensure that the CIS performed to Unitil's exacting standards" and, therefore, that the costs were prudently incurred. Northern Br. at 120.

Northern described the recent CIS implementations of Emera Maine (for its Bangor Hydro District) and Central Maine Power Company (CMP). Emera Maine's final cost was $30.9 million but it endured a $2.4 million disallowance because it allowed the system to go live without full functionality, and there were documented billing errors after go-live. *Id*. at 121 (citing *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360 (Order Part II) (Dec. 16, 2016)). Northern pointed out that CMP's implementation received significant criticism from the Commission, the OPA, and customers, and the Commission "appears poised" to levy a record-breaking penalty for billing errors and issues with customer service.[32] Northern stated that the out-of- pocket costs that resulted from the aftermath of CMP's implementation "must be significant" and the intangible costs are "impossible to assess." *Id*. at 121. Because of the problems with these two CIS rollouts, Northern argued that its $7.8 million investment on behalf of Northern's Maine customers is a "good value." *Id*. at 120.

2. Grant Thornton. Northern argued that USC's decision to hire Grant Thornton to take on a major role in the implementation of the CIS was prudent. Unitil and Grant Thornton had a 20-year relationship and Grant Thornton understood Unitil's philosophy on internal controls. This was important because "Unitil's internal controls philosophy is what drives its rigorous and uncompromising testing philosophy." *Id*. at 113.

In response to the Staff's concerns (expressed in the Bench Analysis) about the lack of written reports from Grant Thornton concerning S&S and its work on the CIS, Northern stated that the firm was not "tasked with providing formal reports or whitepapers," but that it nevertheless communicated regularly with USC management and provided input to the slides prepared for the Steering Committee. *Id*. at 114; ODR-002-013.

3. S&S. Questions about the performance of USC's vendor, S&S, were raised in the Bench Analysis and at the hearing. Northern argued that USC managed S&S and its changing responsibilities "deftly . . . to ensure project success." Northern Br. at 116. Following discussions that led to the project management changes, S&S "responded appropriately" with "renewed vigor" and fell into line with UCS's requirements. Northern Br. at 115–16. USC expected that S&S would perform as needed, despite its changed role, because of concern for its reputation in the CIS marketplace. *Id*. at 114. S&S also added resources to its team without further compensation under the contract. Northern withheld payment under the contract to ensure that S&S "performed its obligations." *Id*. at 115.

Northern defended USC's decision to take over project implementation from S&S, saying that USC "best understands the functional needs of the utilities it serves and is most familiar with the 34 software platforms that interface with the CIS." *Id*. at 103. Northern added that part of the reason for asking S&S to shift gears after the mid- course review was that USC had very high expectations and that "perhaps a vendor like S&S was not accustomed to having very high and, in fact, perfect expectations." *Id*. at 120.

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32 At the time Northern filed its brief, the Commission had not issued the final order in CMP's rate investigation. That order has now been published. *Public Utilities Commission, Investigation into Rates and Revenue Requirements Pertaining to Central Maine Power*, Docket No. 2018-00194 (Order) (Feb. 19, 2020); *see also Public Utilities Commission, Investigation of Central Maine Power Company's Metering and Billing Issues*, Docket No. 2019-00015, Order (Feb. 26, 2020) (finding CMP's implementation of customer billing system to have been flawed).

Responding to questions raised about USC's handling of the problems with S&S, Northern argued that with the complexity of the project, the costs would likely have reached the same level regardless of the vendor hired. *Id*. at 117.

Because its CIS implementation was an operational success, and because of the close attention it paid to ensuring a seamless rollout, Northern asserted that it managed the project prudently in all respects. As such, Northern argued that there is no need for the audit recommended in the Bench Analysis.

Northern argued that allowing partial cost recovery of the CIS in this docket and then potentially allowing recovery of a remaining portion following an audit proceeding would impermissibly violate the statute that requires rate cases to be decided in a nine- month period. Northern pointed to the Emera Maine rate case, during which the Commission initiated and completed an audit of Emera's CIS. Northern Br. at 122, citing to *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360. Northern also cited to *Camden and Rockland, Maine and Wanakah Water Companies*, *Proposed Increase in Rates*, Docket No. 93-145, Order (Part II) (July 12, 1994) for the proposition that it is improper to put off to a subsequent proceeding the ratemaking issues raised in a rate case.

b. <u>Cost Allocation</u>

Northern argues that the Commission should apply the three-factor method for allocating the CIS costs to Maine customers. This would put 22% of the cost into Northern's rate base. Assuming the full cost of $36.8 million, this would produce a total of $7.8 million allocated to Northern's ratepayers. Reacting to the Bench Analysis, which removed plant from the allocation factor resulting in only 20% allocated to Maine, Northern presented several arguments. First, it argues that the Cost Allocation Manual it uses was approved not only by the Maine Commission, but also by the New Hampshire and Massachusetts regulators, and it has been used consistently for allocation of common costs among Unitil's subsidiaries since 2008. CIS Reb. at 29. Second, Northern argues that plant is highly relevant to the CIS since its 34 different software systems and the MDMS are "independent data gathering systems that must all operate together" to meet regulatory requirements. The MDMS is the bridge between the information collected from Northern's meters and the new CIS. The CIS also processes customer requests for service, using work order intake software for new construction authorizations and for repair work on existing plant. Northern Br. at 127. Third, Northern argues that if Maine allows only 20% of costs into rate base but New Hampshire and Massachusetts follow the Cost Allocation Manual, 2% of the CIS costs would be trapped in a "regulatory gap." *Id*. at 128.

ii. The OPA's Position

The OPA agreed with Northern that the rollout of the new CIS was successful from an "operational point of view." OPA Br. at 40. The OPA also agreed, however, with the Bench Analysis that there are unanswered questions about the cost and schedule overruns associated with the project. The OPA listed five areas of concern, including issues surrounding S&S, the specific reasons for the delays and the increased amount of testing, the large number of vendors employed by USC for the project, the "relative scarcity" of concurrent documentation concerning S&S and the mid-course review, and the ability of S&S to deliver a quality project. *Id*. at 41–42. The OPA agreed with the Staff's position in the Bench Analysis that only a 20% allocation of the originally budgeted $12.7 million should be allowed into rate base at this time, pending the results of a follow-on management audit and prudence investigation.

The OPA compared the cost per customer of USC's new CIS with the recent CIS implementations by Emera Maine and CMP. According to the OPA, the cost per customer for Northern's customers was $235.30 versus $193.13 for Emera Maine and $87.70 for CMP. The OPA then questioned whether the extra cost for Unitil was justified by the "trouble free" rollout. *Id*. at 43.

The OPA did not offer testimony on the CIS issue; Mr. Morgan indicated that this was not part of his engagement on behalf of the OPA, nor is CIS implementation within his area of expertise. Tr. at 74–75 (Oct. 10, 2019 Tech. Conf.).

iii The Company's Response

In its reply brief, Northern presented an extensive response to the OPA's brief (see below). First, Northern argued that because it did not produce any evidence on the CIS implementation, the OPA should be precluded from presenting any argument on the CIS subject "at the end of this proceeding." Northern Reply Br. at 25. Northern argues that the OPA could have provided expert testimony on the CIS related issues but did not, and thus claims that the OPA did not meet its burden of production and has thus "waived its ability to raise them now." *Id.* at 26. Northern cites to the OPA's involvement in the recent CMP rate case and billing investigation where the OPA argued that CMP was imprudent because CMP did not do enough testing before it went live with SmartCare. *Id*. at 27. Northern concludes from this that the OPA should be precluded from arguing in this case that USC was imprudent because it did too much testing. Northern adds that it has not had the ability to cross examine the OPA on conflicting positions taken in these cases.

Regarding the merits, Northern provided lengthy responses to five issues briefly raised in the OPA's brief. The OPA identified these issues as reasons for its support of the Staff's proposed resolution in Bench Analysis, including the proposal for a follow-on audit proceeding. OPA Br. at 41. In response to the first, where the OPA asked "why Unitil decided to stay with its vendor after significant delays developed," *id.* at 41, Northern claimed that the OPA had failed to meet its burden of production on this issue. Northern Reply Br. at 28. Northern added that it retained confidence in S&S, that it knew of the various CIS vendors on the market and trusted S&S and its product because S&S was expert with software that had been successfully installed by other utilities.

The second issue raised by the OPA was "what were the specific reasons causing both those delays and the need for Unitil to determine that a significant amount of additional testing was needed." OPA Br. at 41. Northern responded that no audit is necessary, and that the information about the schedule and testing is in the record. Northern Reply Br. at 29.

Third, the OPA questioned "the number of vendors/consultants Unitil involved in the project." OPA Br. at 41. Northern responded that the Company was forthcoming with information about vendors in general and that there is no evidence in the record that hiring Grant Thornton was imprudent. Northern Reply Br. at 30–31.

The OPA next shared the concern expressed by Staff about the "relative scarcity" of documents concerning the issues with S&S. OPA Br. at 41–42. Northern responded that the OPA "misunderstands the nature of Grant Thornton's involvement" with the project, pointing out that Grant Thornton was on site and hands on every day during implementation. Northern also stated that there are many documents not requested and not provided, and that Northern made a good-faith effort to respond to discovery. Northern Reply Br. at 31–32.

Fifth, the OPA questioned "the ability of the vendor to deliver a quality product." OPA Br. at 42. Northern responded that the product was a success and of very high quality. Northern Reply Br. at 32.

In response to the OPA's analysis of the cost per person for each of Emera Maine's, CMP's and Northern's new CIS, Northern pointed out that the OPA included in the Emera calculation customers in the Maine Public District (MPD) where Emera's CIS is not included in MPD's rates. Northern Reply Br. at 33. Northern also argued that because of the shortcomings of Emera's and CMP's implementations, there were costs in addition to the cost of the software systems. *Id*. at 33–36.

iv. Staff's Position

a. CIS Implementation

In its October 29, 2019 Bench Analysis, the Staff addressed several issues on the subject of USC's CIS implementation. BA at 32–48. The Staff expressed concern that Northern's evidence on CIS left significant gaps and about the ultimate cost so far exceeding the budget. The Staff thus proposed that a management audit under 35-A M.R.S. § 113 should be conducted in a follow-on proceeding, with the initially budgeted amount of $12.7 million used as the basis for an addition to rate base for the CIS in this proceeding. The Staff also recommended that a 20% allocation factor be used to determine that amount. Thus, under the Bench Analysis, the Staff would allow $2.54 million into rate base for the CIS at the conclusion of this case, CIS Reb. at 3, and that following the audit proceeding, Northern could seek to adjust that amount, depending on any findings of prudency.

The Staff expressed concerns about the cost increases and the lack of description of the initial budget or why the cost tripled, and about how the utility managed the work of its product vendor, S&S, stating that these issues raised concerns about the reasonableness of the amounts Northern was seeking to recover. The Staff stated that it could not conclude that the implementation was managed prudently, and thus proposed the audit in a follow-on proceeding. BA at 38–39.

The Staff also expressed concern about what it saw as a reticence on Northern's part to respond to discovery about CIS. The Staff observed that Unitil had produced no documents prepared by Grant Thornton in connection with its review of S&S's role in the project and that no written presentations were prepared for Unitil's board of directors. Given that Grant Thornton received $8.1 million for its work on the CIS implementation, the Staff found it difficult to understand this lack of documentation. *Id*. at 40, 42–43. The Staff also expressed concern about the lack of documentation of assessments by Black & Veatch of the responses to the vendor RFP (requested in EXM-005-009). *Id*. at 42.

Because of the questions about the information available to it in testimony and discovery, the Staff explained its difficulty in deciding the amount of CIS costs that should go into rate base pending the audit. Nevertheless, the Staff proposed to include Northern's allocated share of the initial $12.7 million in rate base in recognition that the CIS was needed and that the quality of the go-live benefited the utility and its customers. *Id*. at 45. The Staff added that "there may be reasons to treat the MDMS aspect" of the CIS differently than the other aspects of CIS, given that it was a separate system, was provided by a different vendor and that it has already been put into the rates of the New Hampshire affiliates. *Id*. The Staff then invited Northern to demonstrate in rebuttal that the MDMS should be treated differently, and to provide numbers for determining that part of the rate base.[33]

b. Cost Allocation

Regarding the allocation of costs to Northern, the Staff concluded that it was not appropriate to employ the three-part allocation contained in Unitil's Cost Allocation Manual that used revenues, customers and net plant to derive the allocation percentage. The Staff found that there was no support in the record for the use of net plant for the allocation of CIS costs, stating that the purposes of the new software were to enhance the relationship between the Company and its customers and to provide for billing to obtain revenues. *Id*. at 36–37. Removing net plant from the allocation factor resulted in a 20%, as opposed to 22%, allocation to Northern.

33 Northern did not provide any response to this invitation in its rebuttal.

c. Discussion and Decision

In rendering our decision on the CIS implementation, the Commission first addresses the issue of the allocation factor applicable to Northern, and then moves to discuss the implementation itself.

i. Allocation of costs

USC allocated 22% of the CIS cost to Northern based on the three-factor allocation formula in Unitil's Cost Allocation Manual (CAM) that has been in use at this Commission since 2008. According to the CAM, the allocation factor is "derived from the company ratios of data for Revenue, Customers and Utility Plant Assets." EXM-002-044, Att. 1 at 32 of 343.

In the Bench Analysis, Staff disagreed that utility plant should be included in the allocation formula for CIS. In the Staff's view, no part of the CIS was affected by the amount of utility plant; the CIS was meant to enhance the relationship between the Company and customers and to be used for billing and revenues. BA at 37. In Rebuttal, Northern pointed out that the CIS is related to plant, noting that the MDMS is plant and that it connects the CIS with all of Northern's meters. Further, Northern witnesses testified that the CIS interfaces with work order management (for plant), mobile work order and dispatch and a GIS used by technicians to locate and track gas infrastructure. CIS Reb. at 30.

Since the CAM is designed to allocate costs among different utilities in different states with different regulators, Northern argued that a decision in Maine to reduce the allocation percentage could cause some portion of prudently incurred costs to become trapped. *Id*.

The Commission agrees with Northern that the use of the three-factor allocator is appropriate in this case. We note that Table 6-3 of the CAM shows that this allocator is used for a variety of services provided by USC including "Customer Support" and "Information Systems." Thus, given the Commission's past approval of the CAM and the specific inclusion of Customer Support and Information Systems within the CAM, the Commission finds it appropriate to use 22% as the allocation factor to be used for assigning CIS costs to Northern.

ii Overall Decision to Initiate Management Audit

A customer information system is a very important part of a utility operation and, under 35-A M.R.S. § 301, utilities must provide safe, reasonable, and adequate service at just and reasonable rates. The development, implementation and cost of the system must therefore be accomplished prudently before the investment can be included as part of just and reasonable utility rates. These projects are complex, are difficult to develop, and must be tailored to the specific needs of the utility or utilities it will serve. As with any large investment, questions about any of these implementation elements may therefore trigger an extensive review by this Commission, potentially including a management audit under 35-A M.R.S. § 113.

The Commission finds that there was a need for Unitil to replace its legacy CIS. The legacy system, at the time Unitil began work on the new implementation, had been in place for nearly two decades, was becoming more and more difficult to operate, and thus presented an increasing risk of failure. Also, the vendor of that system had announced that it would soon cease providing support for the software. The OPA did not challenge the need, and the Staff in the Bench Analysis stated that the new software was required.

The Commission recognizes that Unitil's system was activated in early July 2017 without any reported problems. Unitil deserves recognition for this smooth and successful transition. The evidence in this case raises no concerns with the quality of the implementation. The question the Commission is confronted with in this case is, instead, one of cost: whether the amount Northern spent was reasonable and prudent. Did USC spend in excess of what was necessary for an adequate solution to the Company's software and billing needs? As a surrogate for the competitive market, the Commission must in part examine a utility's investments from that point of view. A private business in a fully competitive market would find it difficult or impossible to sell its products at a profit if it overspent on its computer/software system, just as it would if it went live with a terribly flawed system.

In its June 28, 2019 filing, Northern described the need for the new CIS, its many functions and complexity, the development and implementation process it went through, its importance to the operations of its subsidiary utilities, and the benefits to customers it provides. Northern touted the successes of the rollout and customer responses. It discussed how the costs were allocated to Northern. The testimony, however, contained little discussion of the budgeting and costs of the implementation. *See generally* CIS Dir.

Following written and oral discovery, the Staff issued its Bench Analysis in which Staff described the difficulty obtaining information, noting, for example, that there were several initial budget figures for the project, and a lack of documentation explaining why costs tripled between those budget figures and the final cost. Staff indicated that "[a]t this stage, we cannot say definitively whether the implementation was handled prudently." BA at 38. Staff therefore recommended a management audit in a follow-on proceeding during which the prudency of the implementation would be examined.

In its rebuttal testimony, Northern's witnesses provided more detail about the process of the implementation, centering its discussion on five decision points that led USC to increase the resources and time devoted to the project. *See* CIS Reb. Exh. BEL-5(A), (B) and (C). Throughout its testimony on these five items, Northern discussed the process, some of the decisions regarding the use of its vendor and consultants, and its approach to the implementation. There was, however, no meaningful analysis of why Northern spent the specific amounts for the specific choices it made, and whether lesser amounts might have been appropriate. There was little if any discussion of alternatives and options considered and rejected.

Northern noted the three primary constraints for this project—schedule, scope and cost—and that a change in one affects the other two. Northern's witnesses then testified that "USC was not going to compromise on the scope and resulting quality of the project, so was faced with increasing its efforts to achieve its project goals, resulting in increased schedule and cost." CIS Reb. at 13. Northern consistently indicated that it was focused on the quality of the final product.

At hearing, Mr. Lambert, made the following statement:

> Our expectations were very high. Perhaps a vendor at first like S&S was not accustomed to having very high and, in fact, perfect expectations. S&S, as Larry had said earlier, had learned. We had taught them that those were our expectations. So there was really only one way to do that. That was to test 20 times, that was to test 21, 22, 23 times if needed before we cut it over to make sure that we were going to get it right, and, in fact, perfect and achieve the results that we had achieved.

Tr. at 103 (Jan. 22, 2020 Hr'g).

At the August technical conference, Mr. Brock stated that quality was the goal and essentially admitted that cost was not a consideration. He testified that "the progress of the project—all these projects, the goal is a quality outcome, and when you get the goal and how much you spend to get the goal is somewhat—in our methodology, it's what it takes to get it right." Tr. at 79 (Aug. 29, 2019 Tech. Conf.).

The Commission expects that a utility would have a reasonable focus on the quality of any of its investments. We would also expect to see evidence of a balancing of quality with the costs of achieving it. Mr. Brock did testify that there were cost controls for the project, including comparisons to original estimates, and that the "usual cost controls of the company always exist." Tr. at 90 (Aug. 29, 2019 Tech. Conf.). But he did not elaborate. The Commission does not know, then, how management employed these cost controls or what actual price and resource decisions it analyzed in achieving a balance of cost and quality. Perhaps USC simply spent all the funds it considered necessary for the perfect rollout.

Northern had meaningful opportunities throughout this case to describe how Unitil controlled costs through a reasonable examination of the alternatives available at decision points during development. Northern provided one example of this type of analysis when witnesses testified that more USC employees were assigned to the project in 2016 "as these resources were determined to be the lowest cost alternative versus engaging additional third-party resources." CIS Reb. at 24. Otherwise, however, Northern's witnesses made conclusory statements that it prudently managed the project.

For example, following the mid-course review, "management re-aligned existing resources and *committed additional resources* (including USC employees and third- party vendors) to the project . . . ." CIS Reb. at 14 (emphasis added). There was no explanatory testimony about why management chose the specific number of additional resources versus some smaller or larger number. Similarly, with regard to testing, "[m]anagement *committed the necessary resources*," *id*. at 17 (emphasis added), without explaining why a particular amount of resources was necessary versus a different amount. There was no testimony about the tradeoffs considered (if any) in the decision to increase staffing for testing. Rather, the testimony was that management was applying USC's rigorous and comprehensive testing criteria and method. *Id*. For the go-live, USC "committed extensive resources" and "created an entirely new team." *Id*. at 17–18. Other "teams were established to review and triage any issues" during and after the event. *Id*. at 18. All these resources may or may not have been necessary for a reasonable outcome, but without evidence of the tradeoffs and costs versus benefits considered by management (if any) when it made these decisions, we cannot conclude that the decisions were or were not prudent.

Even when Northern's witnesses answered the question "Why does Northern believe that the CIS investments were prudently incurred," the testimony in response failed to address how management developed, considered or evaluated options or alternatives that were estimated to cost more or less than the ones chosen. CIS Dir. at 19–21. These witnesses further testified that "[a]s noted above, management took measures to manage and control costs throughout the project without compromising project quality." *Id*. at 25. It is unclear exactly what prior testimony is referenced here. They then concluded that

> [m]anagement believes the project costs . . . were prudently incurred and necessary to achieve a successful implementation. Project cost management was regularly monitored and discussed at the senior management, executive and Board level.

Id. The Commission is under no obligation to accept this conclusory testimony where it lacks support, elaboration, or description elsewhere in the record.

At the January technical conferences, Northern's witnesses were specifically asked to describe, with reference to each of the five decision points in Exhibit BEL-5(A), any analyses of costs and benefits or tradeoffs concerning alternatives or options that were considered by management. Tr. at 28–38 (Jan. 6, 2020 Tech. Conf.). In each instance, Northern's responses did not describe such analyses.[34] The Commission notes, however, that Mr. Brock provided an illuminating response concerning USC's project management (block #2 on Exhibit BEL-5(A)) when he described how management broke the project down into "more discrete, achievable functions" and then assigned personnel to those functions. *Id*. at 31. This is useful but does not allow us to make a prudence determination.

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34 In response to EXM-015-001, Northern stated that it had already provided all "documents, analysis, or other materials" that support the information in Exhibit BEL-5(A).

The following is representative of Northern's testimony on its management of project costs:

> MS. GRAY: How would you describe the costs associated with this demotion of the vendor? We have the Grant Thornton costs apparently. What other costs were incurred by the company relating to this problem that you encountered, costs that you wouldn't have otherwise had to incur? Is that something you can describe or quantify?
>
> MR. BROCK: I believe all the costs that were expended were necessary to complete the project, including bringing in the additional resources which included Grant Thornton. The complexity of the project and the scope of the steps necessary to complete the project happened as they needed to over the horizon, over the time horizon they needed to, and resulted in a successful implementation. I can't identify any money that we spent that was not necessary to complete that project.

Tr. at 69–70 (Aug. 29, 2019 Tech. Conf.)

Without evidence of management's analysis of the costs and benefits of the many increases in spending during the course of this project, and a discussion of alternatives or options considered and rejected, whether they were estimated to cost more or less than what was actually spent, the Commission is unable to reach a conclusion about the prudence of USC's investment decisions.

Perfection is not a standard for prudence, as Northern has acknowledged. Northern Br. at 111. A utility's billing and customer service software, like any of its investments, must be safe, adequate, and reasonable. If an investment is, in fact, perfect and the decisions that led to that perfection are found to be prudent, then that is a very good result. That may be the case here. However, from a prudence standpoint, Unitil's drive for perfection in rolling out its new CIS raises concerns. Could a reasonable CIS have been implemented for less than $36.8 million? Was USC's hiring of Grant Thornton midway through the project a decision that saved the project from disaster or was it evidence of unnecessary spending, or something in between? Should USC have used a bid process instead of simply hiring Grant Thornton to review the work of S&S and take over implementation? These are questions not fully answered in this proceeding.

There are several discrete areas where information is lacking or where the information provided raises questions that require further investigation by a qualified auditor.

a. Concerns about Documentation

The Bench Analysis raised concerns about a lack of documentation associated with the CIS project. BA at 42–44. In addition to the concerns raised there, to which Northern responded, CIS Reb. 31–34, the Commission notes other areas with a lack of documentation.

The concerns that USC developed during the project with its primary vendor, S&S, were not documented. Tr. at 76–78 (Aug. 29, 2019 Tech. Conf.). Northern did submit a letter dated September 2016 (well after the issues with S&S were first identified) but the letter does not provide this documentation. CIS Reb. Exh. BEL-6. This letter references a mid-September 2016 meeting. In EXM-015-013, Northern was asked to provide “any meeting notes, agendas, follow-up correspondence, presentation material, or other documents” related to that meeting. Northern stated there were none.

Northern was asked to “provide any summaries of the change in the scope of the project that were provided in the quarterly meetings with S&S.” None were provided. The Company referred instead to the “open dialogue” between USC and S&S and that the formal agreement, amended twice, was the “record of the scope of the project.” ODR-002-023.

At hearing, counsel for the OPA asked Mr. Brock, “why wouldn’t you comprehensively document the problems and concerns you were having with your vendor?” The answer was that “there was no published whitepaper or report on the vendor by Grant Thornton. It was interactive, ongoing consulting and advice.” Tr. at 57–58 (Jan. 22, 2020 Hr’g).

At hearing, Northern’s witnesses testified that all written analyses that had been prepared during development and implementation “that discuss and justify adding to the costs of the project that led to the ultimate $38 million that was spent or 37 that was spent” had been provided in discovery. Tr. at 81 (Jan. 22, 2020 Hr’g).

In sum, though requested, the Company has not produced concurrent reports, minutes or prepared summaries of management decision analysis related to the increase from its original $12.7 million cost estimate to the $36.8 million ultimately spent. This is surprising given that management knew it was a complex and dynamic project and that it would be subject to regulatory scrutiny. *See* Tr. at 78 (Aug. 29, 2019 Tech. Conf.). Even following the Bench Analysis, the Company’s rebuttal lacked evidence of management’s analysis of cost alternatives that might have been available and how management made its decisions in the face of alternatives. The Commission finds it difficult to understand how managers of a company that owns regulated utilities operating in three separate states could make multimillion-dollar investment decisions without creating and preserving reports that describe, at a minimum, the cost/benefit analyses that should accompany such decisions. To be clear, the Commission is not making a finding about the good faith of Northern in responding to discovery. Rather, with the Company bearing the burden of proof on this question, the absence of the type of evidence described herein is by itself a sound reason for an audit. At hearing, Northern referred to a large amount of correspondence that was not requested and therefore not provided. Tr. at 59–60 (Jan. 22, 2020 Hr’g). The audit may find further evidence—in the documents not presented in this case (e.g. email traffic) or through interviews the auditor may conduct with implementation personnel—that support the Company’s position.

b. Inconsistent Budget Information

Unitil's budgeting information in the record is inconsistent and contains gaps. The initial project budget is shown in ODR-002-017, Att. 1. In its rebuttal, the CIS witnesses presented Rebuttal Exhibit BEL-5(C), which, they said, "compares the planned versus actual spend for the CIS project on a quarterly basis for March 2012 through December 2017." However, this information is not provided for the entire length of the project; the columns showing "Planned Spend" and Planned Spend Cumulative" are blank beginning in the third quarter of 2015, just when spending significantly began to ramp up. For these two columns, Exhibit BEL-5(C) references ODR-002-017, which has two attachments. The first attachment appears to be the original budget and shows significant detail. But when USC stepped into the shoes of S&S to manage the project, and more and more resources were brought in, there is little evidence of budget estimates. Some information is in the second attachment to ODR-002-017, but it is at a very high level and it does not provide "Planned Spend" information on a quarterly basis. Rather, there is a "Forecast Q4 2016" forecast, ODR-002-017 Att. 2 at 2, and a "Forecast 2017" forecast, *id*. at 5 & 7, both of which are broken down into four broad, high-level categories. Thus, the Commission lacks meaningful budgetary detail from the third quarter of 2015 through to the end.

Some budget and cost information is provided in EXM-005-033 Attachment 1 in the form of what appear to be after-the-fact capital-spending authorizations. This document contains five such authorizations, dated 2/12/13, 4/16/14, 12/1/15, 4/6/16 and 1/11/18. The 2015 and 2016 authorizations are largely identical, including the "Justification" section; however, these appear to be separate authorizations since the first states that it is "for the 2015 spending on the new CIS system," EXM-002-033, Att. 1 at 4, and the second indicates that it is the authorization for spending in 2016. *Id*. at 5. Further, it appears that there were no budget authorizations produced between April 2016 and January 2018. These inconsistencies raise questions about how USC performed its budgeting.

While it is not clear whether these were after-the-fact spending authorizations, Unitil's budgeting process, according to Northern's description provided in EXM-008-008 Att. 1, appears to require prior approval:

> Capital budget approval by Senior Management and the Board of Directors does not give the authorization or approval to spend money to complete projects. After the budget is approved, each project within the budget must be further authorized before spending can occur.

Mr. Brock testified that project managers did not understand the complexity of the project, and therefore the resources and time necessary to implement the CIS, until well into implementation. Tr. at 27 (Jan. 6, 2020 Tech. Conf.). He stated that "until you get into the project, you don't—the managers really are still defining the scope of what they want to accomplish, but once you're in the middle of a project, you have a very clear idea of how you're going to finish it." *Id*.

Despite having this clear idea in the middle of the project, USC was, at the end of 2016, unable to estimate remaining costs with reasonable accuracy. By then, Northern had spent $25.4 million on the CIS project. Exhibit BEL-5(C). At that late date, Northern forecasted the final project to cost [**BEGIN CONFIDENTIAL**] ******************** ********** [**END CONFIDENTIAL**] less than the final cost. ODR-002-017 Att. 2 at 7 of 8.[35] In other words, with six months to go, Northern's forecast of its remaining costs to implement CIS was low by [**BEGIN CONFIDENTIAL**] *** [**END CONFIDENTIAL**].[36]

c. Grant Thornton

Unitil did not use an RFP process to hire Grant Thornton to work on a review of the CIS project and then as a project implementer. Tr. at 86 (Jan. 22, 2020 Hr'g). Rather, it appears that Grant Thornton was hired for this work in large part because of its accounting, audit and tax preparation work for Unitil. Mr. Brock testified that Unitil had a "long relationship" with Grant Thornton and that the firm was "a trusted, reliable resource." Tr. at 92–93 (Jan. 22, 2020 Hr'g). It is not clear why the software- implementation expertise of an accounting firm was desirable for this work, or whether the cost was reasonable. Mr. Brock also testified that hiring Grant Thornton was prudent because of the firm's knowledge of Unitil's internal controls. While there may be a reasonable connection between internal controls and USC's need for CIS project management expertise, it is not obvious from this record. Mr. Brock's testimony that Grant Thornton shared Unitil's "philosophy on internal controls" is not persuasive. *See* Northern Br. at 114. It may be the case that Grant Thornton was eminently qualified for the work and that the money spent was reasonable considering all the variables, but these are hypotheses to be examined in the audit.

Grant Thornton entered into a letter agreement with USC in early September 2015. ODR-002-019, Att. 2. The provisions of this agreement are not entirely consistent with Northern's testimony in this case. First, it contains little reference to accounting controls. Item 6 under "Quality and Risk Management on page 3 of 15 references "audit validation testing" and then recites "three phases of implementation: Conversion, Operation, and Monthly closing and interfaces. (according to GAAP, CAAS, and the Company's Internal Controls under COSO)." *Id.* at 3. It also states that Unitil's responsibilities include establishing effective internal controls. *Id.* at 5.

Second, the letter agreement estimates total fees ranging from $2.7 million to $3.25 million. The record does not reveal whether the total paid to Grant Thornton included the accounting work it was doing prior to this agreement or if the estimated range in the agreement was supplemented and documented. Either way, the estimated amount is well below half of the $8.1 million Grant Thornton was ultimately paid.

35 This data response attachment is marked confidential. Budget forecast numbers from other documents, such as Exhibit BEL-5(C), are, however, not confidential.

36 The Company estimated it would spend an additional [**BEGIN CONFIDENTIAL**] *************************************
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** [**END CONFIDENTIAL**]

Finally, the agreement requires Grant Thornton to “prepare and submit weekly Status Reports” to the stakeholder group and the Executive Project Sponsor. *Id*. at 3. This is at odds with Northern’s assertion that Grant Thornton was not hired to write reports. Northern Br. at 114. If any such reports were prepared and submitted, they were not provided in this proceeding.

d. <u>S&S</u>

In its Bench Analysis, the Staff described some of the reasons for what it called Unitil’s 2015 “demotion” of S&S.[37] These reasons included a three-month delay in project schedule that developed soon after S&S’s work commenced, Tr. at 56 (Aug. 29 Tech. Conf.), and the conclusion that “S&S was not fully leveraging the knowledge of Unitil’s project team.” Staff also referenced Unitil’s apparent belief that S&S’s “process for introducing and validating new code needed to be strengthened.” BA at 39 (citing EXM-005-011).

Further reasons for the change surfaced in the remainder of this proceeding. In Rebuttal, Northern’s witnesses made the following statement:

> Because every utility’s business processes are unique, every CIS implementation is unique. It is the CIS vendor’s responsibility to customize its CIS product to match the Company’s business requirements; it is not the Company’s responsibility to compromise on quality or its business processes to match the vendor’s CIS product.

CIS Rebuttal at 12, 13. Northern attached to its rebuttal testimony confidential Exhibit BEL-6 about which Company witnesses were questioned at hearing. [**BEGIN CONFIDENTIAL**] **
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** [**END CONFIDENTIAL**]. Mr. Brock testified that USC could have stayed with S&S as its project implementer but that the project could have taken much longer. Tr. at 68 (Aug. 29, 2019 Tech Conf.). However, Unitil was clear that of the three potential primary constraints to such a project—schedule, scope or cost—“USC was not going to compromise on the scope and resulting quality.” CIS Reb. at 13. It is unclear whether Unitil could (or should) have kept to its original budget of $12.7 million if it had been willing to extend the schedule.

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[37] Northern disagreed with the term demotion. CIS Reb. at 15.

iii. Conclusion on Prudency

With the evidence in the record, and the questions raised by that evidence, the Commission is unable to conclude that the total amount spent was prudent. While offering conclusory testimony supporting prudence, Northern has not presented decision point cost analysis evidence sufficient to inform the Commission about the prudence of many of the major decisions of management. Moreover, Northern has been unable to provide documentary evidence, concurrent with management decisions about cost, that the amounts spent were reasonable. There are significant questions about Unitil's budget process and about the primary vendors that worked on the project. With these issues and questions, we do not know, based on this record, whether the amounts spent were prudent or whether the new CIS would have functioned adequately if the total cost had been an amount less than Unitil's actual final cost. We find, therefore, that Northern has failed to carry its burden of proof that the total cost of implementing its new CIS was prudently incurred.

The Commission agrees with Northern that CIS implementations are difficult and complex, particularly in this situation where the system must serve the needs of multiple types of utilities in three different jurisdictions. Moreover, it is not unusual for such projects to run over budget and take longer than initially planned. In this case, there was no question that the new CIS was needed in order to replace an aging system. And, importantly, USC deserves recognition for its flawless rollout in July 2017. Thus, the Commission finds that a portion of the total CIS cost was prudently incurred.

iv. Amount of CIS Costs Determined to Be Prudent

The Commission concludes, for the reasons given below, that the initially- budgeted amount of $12.7 million was prudently spent implementing the CIS project and that Northern's allocated share of that amount may therefore be put into rate base at the conclusion of this proceeding.

Because USC's documentation of its budgeting process as well as the amounts actually spent over time are unclear, and because Northern has not met its burden of proof, the decision of what amount to include in rates at this time is not an easy one. The project was initially budgeted to cost anywhere from $11.5 million to $13.3 million. See ODR-002-017, Att. 1 where the sum of all "grand total" estimated costs (other than "total authorization") on the "Summary" tab is $13.3 million, though the "total authorization" amount is $12.7 million. *See also* EXM-005-033, Att. 1 at 1 (showing "original estimate" of $11.5 million); BA at 33. In its rebuttal, the Company appeared to endorse $12.7 million, the amount ultimately adopted in the Bench Analysis, as the initially-budgeted amount. CIS Reb. at 24-25. This figure is supported by significant detail in ODR-002-017 Att. 1, a multipage spreadsheet showing year-by-year cost estimates for a wide variety of cost causers.

Exhibit BEL-5(C), presented as part of Northern's rebuttal, shows a quarter-by- quarter budget-versus-actual cost comparison.[38] On this exhibit, the original budget of $12.7 million remained the operating budget through the end of the second quarter of 2015, just before costs began to escalate. This exhibit shows $12,693,277 in the column labelled "cumulative planned spend" as of the end of the second quarter of 2015. The amount spent as of this time was $11,443,652, not far below the budgeted amount. Thus, it appears that two years in, project costs were on track as originally budgeted. For these reasons, we find that $12.7 million is a reliable figure and thus an appropriate amount to reflect in rates at this time. Therefore, we will allow Northern to put into rate base $2,648,479, which reflects Northern's 22% share of the allowed asset balance at year-end 2018 ($12,038,542 × 0.22).

As explained above, the Commission initiates a management audit in a follow-on proceeding and not as a part of this docket. We acknowledge Northern's arguments that ratemaking issues must be decided in the nine-month window of a rate case. Northern Br. at 122. Because of our finding, however, that Northern has failed to meet its burden of proof, this issue is moot.

The Commission could conclude that this finding obviates the need for any further examination of the CIS costs. However, a CIS is vital to a utility, and there is significant complexity and difficulty associated with a CIS implementation. Also, the cost of a CIS is high relative to other investments a utility may make from time to time. For these reasons, and for those stated earlier in this order, the Commission concludes that it is appropriate to continue the examination of the prudence of these costs and therefore initiates a management audit of Unitil's implementation of the CIS. The audit will be conducted pursuant to the provisions of 35-A M.R.S. § 113 and will occur in a separate proceeding following the conclusion of this docket. The Commission will select the auditor and Northern Utilities shall pay the costs of the audit. The Commission will decide, based upon the results of the audit investigation, whether to allocate some or all of the audit costs to Northern's ratepayers.

The audit will examine all aspects of Unitil's CIS implementation[39] and will seek to provide a basis upon which the Commission may decide the prudence of any investment expenditures beyond those found to be prudent in this docket. Following the filing of the consultant's final audit report, the Commission will conduct an adjudicatory proceeding, based upon that report, to determine what other amounts, if any, were prudently incurred.

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38 For reasons not explained, no budgeted amounts are shown on this document from the third quarter of 2015 through the end of the project.

39 In the Bench Analysis, the Staff suggested that the costs associated with the MDMS could possibly be treated differently from the other portions of the CIS and invited Northern to provide testimony and evidence in rebuttal to that effect. BA at 46. Because Northern did not respond to this invitation, the MDMS implementation will be a part of the audit.

The Commission may conclude, following the audit and subsequent adjudicatory proceeding, that the entire $36.8 million was prudently spent, or that, in addition to what the Commission has allowed here, some amount less than that total was prudent.[40] If so, Northern will be allowed to seek to add those costs to rates at the time of its next TIRA adjustment,[41] or next general rate case, whichever occurs first.

Northern has requested that, for any amounts found to be prudent at the conclusion of the follow-on audit investigation, this order provide for "an accommodation of addressing the accounting issues." Tr. at 85 (Jan. 22, 2020 Hr'g). We are unsure how broad an accommodation Northern seeks but we will not allow carrying costs to be accrued and deferred for later recovery on any amounts in excess of the $12.7 million amount discussed above that are later found to be prudent in the follow-on audit and investigation. However, until the audit investigation is completed, Northern need not write off from its plant balances any CIS-related amounts; Northern may continue to record those amounts on its books. At that time, Northern will be required to make any necessary adjustments on its books and records to reflect the final decision.

In its reply brief, Northern argued that the OPA should be precluded from briefing its position on the CIS implementation because it had offered no evidence on the subject during the case. Northern asserted that the OPA did not meet its burden of production. The Commission disagrees and rejects Northern's argument. Northern is conflating evidence with argument. No party may offer any evidence for the first time at the briefing stage of a proceeding. The OPA is not, however, offering evidence in its brief. In fact, the OPA cites to testimony and documents allowed into the record by the Examiners, all of which was either submitted by Northern, or in the case of the Bench Analysis, was subject to discovery and cross-examination. As a matter of argument, any party is allowed to brief issues in the case, citing to record evidence it believes supports those arguments, whether or not it sponsored or provided that evidence in the first place.

v. Document Retention

In the course of the proceeding, Northern was asked about its record-retention policies and how those policies are communicated to employees. Northern indicated that it follows the record-retention policies prescribed by the National Association of Regulatory Utility Commissioners (NARUC), as well as relevant federal and state laws and rules, but that it does not have a specific written policy. EXM-015-002; ODR-005-004. The Company added that it does not have a written policy used

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40 40 This decision is not unlike that in *Emera Maine, Request for Approval of a Proposed Rate Increase*, Docket No. 2015-00360, Order – Part II at 27 (Dec. 22, 2017). In that rate case, the Commission found that only a portion of the cost of a new substation was prudently incurred because the utility had not met its burden of proof that the full cost was prudent. While no audit was initiated, the utility was invited to initiate a follow-on proceeding in which it could present its full case on prudence.

41 If any costs of the CIS implementation are added during a TIRA case, the inclusion of those costs would not be counted toward the 4% cap.

companywide for training new hires on record retention, but that each functional manager is responsible for the orientation of new employees, including standard operating procedures used for that department. Tr. at 15–16 (Jan. 6, 2020 Tech. Conf.).

The Company stated that no records related to the CIS project have been purged, altered, removed, or destroyed for any reason, ODR-005-004, Tr. at 59–60 (Jan. 22, 2020 Hr'g) ("[A]ll of our documentation on the CIS . . . implementation project . . . has been retained."), and there has been no suggestion in this proceeding that any such activities occurred. However, given the lack of a written document-retention policy or consistent formal training for new (or existing) employees, the Commission believes that there is room for improvement in the Company's record-retention practices both to better equip employees to adhere to federal and state document-retention rules and to ensure that documents are available for Commission review in regulatory proceedings as needed. Accordingly, the Commission orders the Company to develop a written document-retention policy that includes information on how the policy will be communicated to new and existing employees, and to submit that policy for informational purposes as a compliance filing within 90 days of Order (Part I), which issued March 26, 2020.

C. Cost of Capital and Capital Structure

1. Positions of the Parties and Staff

a. Northern

In its brief, Northern argued that the Commission should authorize a 10.50% return on equity (ROE), which is within the range of 10.00% to 10.75% developed by its cost-of-equity witness, Mr. Robert Hevert. Northern Br. at 47. Northern also argued that the Commission should set the common-equity ratio at 52.91%, a level it says is consistent with the Company's proforma test-year capital structure, industry norms, and investor requirements. *Id*. at 36. Northern's proposed ROE and capital structure, combined with the cost of debt, results in an after-tax weighted average cost of capital (WACC) of 8.00%. *Id*. at 47. The Company argued that its proposed ROE reflects current capital market conditions and is based on the careful application of widely recognized financial models, including the Constant Growth Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM), and the Bond Yield Plus Risk Premium approach, corroborated by an Expected Earnings approach. *Id*.

The Company argued that, despite using a largely overlapping proxy group, the Staff applied no materiality threshold for the merger- or acquisition-activity screening criterion and thus wrongly eliminated one company from its proxy group. *Id*. at 50–53. Noting that the principal difference between the Staff's DCF analysis and the Company's is the exclusion of Northwest Natural Holding Company (Northwest Natural) from the proxy group, Northern stated that, by excluding this one company, Staff's analysis omitted a critical component of the DCF analysis. Thus, Northern argued, Staff's analysis is less reliable than that of the Company's witness. *Id*. at 62–63.

The Company also argued that the Staff's application of the Capital Asset Pricing Model produces an unreliable result because the Staff removed companies from the calculation of the market risk premium that do not pay dividends or that have a negative or no growth rate. Removing these companies from the calculation, Northern asserted, has a significant effect on the calculated market risk premium and produces an estimate that is not representative of the market as a whole. *Id.* at 69. Northern also rejected the Staff's proposed common-equity ratio of 50%, stating that, among other things, it ignores the trend to adjust equity ratios upward in response to the Tax Cuts and Jobs Act of 2017 (TCJA). *Id*. at 79. Instead, Northern asserted that its proposed 55% common-equity ratio is reasonable, maintains its ability to attract capital, and reflects its actual capital structure and that of its proxy group. *Id*. at 78.

With respect to the OPA's recommended ROE, Northern argued that the application of the DCF model by the OPA's cost of capital witness is "fatally flawed" and is not reliable for the purpose of establishing an ROE in this case. *Id.* at 64. Northern criticized the way the OPA's witness adjusted the Value Line earnings-per-share growth rate, characterizing it as manipulation of the data set that renders the OPA's DCF analysis unreliable. *Id*. at 66. Northern also argued that the CAPM analysis presented by the OPA's witness, like the Staff's CAPM analysis, "fundamentally destabilizes the CAPM analysis." *Id*. at 69. Thus, the Company asserted, the only reliable CAPM analysis in the record in this case is that presented by its witness. *Id*. at 70.

In its reply brief, Northern again argued that the OPA's analyses are unreliable and artificially low because they rely on manipulated data and that the recommended ROE falls below those of other gas utilities. Northern Reply Br. at 15. The Company repeated its criticism of the method the OPA used to adjust the growth rate for Northwest Natural in its DCF analysis and the method used in the CAPM analysis to calculate the market risk premium. *Id*. at 17–18. Finally, Northern argued that the Bond Yield Plus Risk Premium model and Expected Earnings approach included in its analyses are sound and should be given appropriate weight by the Commission. *Id*. at 18–19.

In its exceptions, Northern objected to the use of a hypothetical capital structure with a 50% equity layer, stating that the Company's actual capital structure is reasonable and supported by the evidence in the record. The Company asserted that maintaining a capital structure with a range of 52%–54% common equity is a proactive measure to mitigate the effect the TCJA will have on Northern's cash flow and credit metrics. With respect to ROE, the Company asserted that Northern's DCF analysis, which has a mean result of 9.95% to 9.98%, is the most credible analysis in the record and should be accepted by the Commission. Finally, Northern argued that the evidence in the record supported the incorporation of a flotation cost adjustment and stated that no party had contested the calculations of its witness, which supported an upward adjustment to ROE for flotation costs of eight basis points.

b. Office of the Public Advocate

The OPA argued that the Commission should reject Northern's proposal and authorize an ROE of 9.25% combined with a common-equity ratio of 52.91%. The OPA stated that this would result in an overall rate of return for Northern of 7.34%. OPA Br. at 33. In developing its recommended ROE, the OPA's witness, Dr. Griffing, developed a comparison group of domestic gas utilities with risk profiles similar to Northern's and applied a Constant Growth DCF model, a Multi-Stage Growth DCF model, and a CAPM model as a check on the reasonableness of the DCF results. This approach, the OPA argued, is a market-oriented approach used to determine the cost of equity for a regulated public utility and is consistent with Commission precedent. OPA Br. at 22.

The OPA argued that Northern's proposed ROE is the product of a flawed analysis and should be rejected. *Id*. at 33. The OPA pointed to the inclusion in the Company's DCF analysis of the Value Line earnings-per-share growth rate for Northwest Natural of 27.00%, an estimate the OPA characterized as an "extreme outlier" among other growth rates used in the analyses. *Id*. at 34. The OPA's witness excluded this estimate from his analysis, asserting that the Value Line earnings-per-share growth rate accounts for a difference of 84 basis points between the OPA's DCF ROE results of 9.04%, which exclude the Value Line growth rate for Northwest Natural, and the Company's DCF result of 9.88%, which include that growth rate. *Id*. The OPA also argued that the Company's CAPM return is inflated by the inclusion of non-dividend- paying companies in the calculation of a market return and market risk premium. *Id.* at 35.

Finally, the OPA argued that the results of Northern's Bond Yield Plus Risk premium model and Expected Earnings approach should be excluded from consideration because of their flaws. Specifically, the Bond Yield Plus Risk Premium model as applied by the Company includes authorized ROEs that are the results of settlements, which often reflect compromises on issues in a case other than market- based analytical information. The Expected Earnings approach, the OPA asserted, is also flawed because it relies on the book value of common-equity shares, not prices that prevail in the market. *Id*. at 37–38.

In its exceptions, the OPA questioned the Examiners' use of the term "infirm" in describing the DCF analysis of its witness. Rather, the OPA stated, the analytical choice of its witness was simply based on an approach that Staff declined to follow.

c. Staff

In its Bench Analysis, the Staff recommended an ROE of 9.40% and the use of a capital structure with common equity equal to 50.00% and long-term debt equal to 50.00%. In arriving at its ROE recommendation, the Staff developed a proxy group of natural-gas utilities and used a Constant Growth DCF analysis and a CAPM calculation as a check on the DCF results. The Staff developed a DCF range of 7.20% to 11.53% in its Bench Analysis with an overall average of 9.40%. BA at 18. Staff's CAPM analysis indicates an ROE range of 7.39% to 9.18%. BA at 21.

2. The *Hope-Bluefield* Standard

Two U.S. Supreme Court decisions of more than 70 years ago, known as *Bluefield* and *Hope*, provide the standards for measuring the reasonableness of a utility's allowed ROE. Taken together, the *Hope* and *Bluefield* decisions establish that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made . . . on investments in other business undertakings which are attended by corresponding risks and uncertainties . . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 692 (1923). The idea of associating the allowed return to a common-equity owner with those available from other companies of comparable risk was established in the *Hope* decision:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944). Together, these principles form what is known as the *Hope-Bluefield* standard.

Based on that standard, determining an appropriate ROE for a regulated utility involves determining a market-based cost of equity. For a company that is not publicly traded, such as Northern, the cost of equity is determined to be the return investors expect from alternative investments that present no more and no less risk. In practice, estimating the cost of equity involves developing a comparable group of companies (the so-called proxy group), for which market-based information is available, that are in lines of business that present similar financial risks, and using economic and financial models to set an appropriate ROE. The *Hope-Bluefield* standard has long served as the benchmark against which this Commission measures an appropriate ROE.

3. Discussion and Decision

a. Market Based Analyses and Models

Because the Commission's approach to determining an appropriate ROE is market-based, capital-market conditions and expectations of earnings and returns are fundamental to utility cost-of-equity analysis. The model the Commission primarily relies upon is the DCF. The Commission then looks to the CAPM as a check. Both models are market-based analytical approaches that incorporate current market-related data. Consistent with the Commission's approach, the expert witnesses in this case and the Staff presented results using these two models. In addition, Mr. Hevert presented ROE results using an additional model, the Bond Yield Plus Risk Premium approach, and an Expected Earnings analysis as a method of corroborating the results of the market- based models. Northern Br. at 55–59.

The Company's Bond Yield Plus Risk Premium analysis is based on the principle that equity investors bear the residual risk associated with ownership, and therefore require a premium over the return they would have earned as a bondholder. ROE Dir. at 22–23. Mr. Hevert compared the difference between the *allowed* ROE and the then- prevailing Treasury yield from 1,120 natural-gas utility rate cases from January 1980 to May 2019. He developed an equity-cost rate by regressing the authorized ROE on the 30-year Treasury yield in effect at the time of each rate case and adding the resulting risk premium to current and projected Treasury rates. His results updated in rebuttal ranged from 9.93% to 10.00%. ROE Reb. at 59. Neither the OPA nor the Staff presented a Bond Yield Plus Risk Premium analysis.

As noted in the Staff's Bench Analysis, the analytical approach to determining an appropriate ROE range is based on obtaining and analyzing information that results from the financial decisions of investors, not regulatory agencies. BA at 22. Although the commissions making the ROE decisions presumably had market-based analytical information in front of them, those decisions are likely to reflect other specific information related to the utility and the issues presented in that rate case. As such, the Commission declines to include the results of the Company's Bond Yield Plus Risk Premium analysis in our decision.

Similarly, the Commission agrees with the OPA about the shortcomings of the Expected Earnings Model and does not find the results presented to inform the question of an appropriate ROE to authorize for Northern in this case.

b. Proxy Group Selection

As an initial matter, ROE analysis requires the development of a proxy or comparable group of companies for which market information can be obtained. The Company's witness followed a customary approach for selecting a proxy group of publicly traded utilities that are representative of the risks and prospects faced by Northern.

Mr. Hevert began with the universe of companies that Value Line classifies as Natural Gas Utilities, and applied the following screening criteria:

(a) Companies have consistently paid quarterly cash dividends;

(b) Have been covered by at least two utility industry equity analysts;

(c) Must have investment grade senior unsecured bond and/or corporate credit ratings from S&P, or a comparable financial strength rating;

(d) Have at least 60 percent of operating income derived from regulated natural gas utility operations; and

(e) Are not currently known to be a party to a merger, or other significant transaction.

This left a proxy group of eight companies: Atmos Energy Corporation, Chesapeake Utilities Corporation, New Jersey Resources Corporation, Northwest Natural Holding Company, One Gas, Inc., South Jersey Industries, Inc., Spire, Inc., and Southwest Gas Corporation. ROE Dir. at 15–17. In the Company's rebuttal testimony, Mr. Hevert reduced the proxy group from eight companies to seven by removing Chesapeake Utilities because it no longer met the screening criteria of earning 60% or more of its operating income from regulated natural-gas operations. ROE Reb. at 7.

Dr. Griffing started with the 10 utilities included in the Value Line universe of Natural Gas Utility Industry companies and applied the following screens:

(a) Shares publicly traded on a stock exchange;

(b) US Firm based in the continental 48 states;

(c) Stable record of paying dividend;

(d) Not expected to sell, merge into or be acquired by another company, or be engaged in an unusual regulatory proceeding;

(e) Have an investment grade credit rating (BBB- or better);

(f) Have 60 percent or more of the three-year average of net income, net operating income, or operating revenue be derived from regulated natural- gas distribution operations; and

(g) Have a positive growth-rate projections from expert analysts.

Griffing Dir. at 12–13. Dr. Griffing maintained all the same companies as Northern's proxy, but added back NiSource, which had been removed from the Company's proxy group. Mr. Hevert had initially excluded the company based on the September 2018 incident in the Merrimack Valley involving its subsidiary Columbia Gas. EXM-007-004, Att. 1. Dr. Griffing determined that enough time had passed since the incident and NiSource should be included in the comparison group. Staff concurred with Dr. Griffing's decision based on the fact that almost a year had passed, and the capital markets have presumably reflected any expected effect on the financial strength of NiSource.

The final comparison groups included in the analyses in this case are shown in Figure 3.

Figure 3: Proxy Groups

Northern Direct Testimony	Northern Rebuttal	OPA	Staff
Atmos Energy Corporation	Atmos Energy Corporation	Atmos Energy Corporation	Atmos Energy Corporation
Chesapeake Utilities Corp		Chesapeake Utilities Corp	Chesapeake Utilities Corp
New Jersey Resources Corp	New Jersey Resources Corp	New Jersey Resources Corp	New Jersey Resources Corp
		NiSource Inc.	NiSource Inc.
Northwest Natural Holding Company	Northwest Natural Holding Company	Northwest Natural Holding Company	
ONE Gas, Inc.	ONE Gas, Inc.	ONE Gas, Inc.	ONE Gas, Inc.
South Jersey Industries, Inc.	South Jersey Industries, Inc.	South Jersey Industries, Inc.	South Jersey Industries, Inc.
Southwest Gas Corp	Southwest Gas Corp	Southwest Gas Corp	Southwest Gas Corp
Spire, Inc.	Spire, Inc.	Spire, Inc.	Spire, Inc.

Northern criticizes the Staff's exclusion of Northwest Natural from its proxy group. Northern Br. at 50–53. Northern explains that Staff "improperly excluded Northwest Natural Holding Company from the proxy group based on one or more small water company acquisitions that are [not] material when considered in the context of the Company's complete operating profile." Northern Br. at 62–63. In addition, Northern is critical of the adjustments Dr. Griffing made to remove the Value Line earnings per share growth estimate from his analysis, noting that this "manipulation" of the data set is problematic in that it lacks credibility and is inconsistent with other decisions made by Dr. Griffing in the structure of his analyses. Northern Br. at 65.

The inclusion of Northwest Natural in the proxy group and the inclusion or exclusion of its Value Line earnings-per-share growth rate may appear at first examination to be a relatively minor issue. However, the treatment of this data point in the DCF analysis has a significant effect in the results of the analysis. As noted, the OPA contended that the decision to include or exclude the Value Line earnings-per-share growth rate accounts for a difference of 84 basis points between the OPA's DCF ROE results of 9.04%, which excludes the Value Line growth rate for Northwest Natural, and the Company's DCF result of 9.88%, which includes that growth rate. OPA Br. at 34. Staff also provided an assessment of the effect of the Northwest Natural growth rate on the DCF results in the Bench Analysis, stating that "Staff estimates that replacing the Northwest Natural growth rate of 25.50% with the next highest growth rate for the proxy group of 9.50% would reduce Mr. Hevert's mean ROE estimates by approximately 50 basis points and his mean-high estimates by approximately 200 basis points." BA at 16.

The Value Line earnings per share growth projection certainly appears to be an outlier when compared to growth rates from other sources. Moreover, because the comparison groups used by Dr. Griffing and Mr. Hevert are relatively small, seven to eight companies, as compared to a proxy group in an electric rate case of 20 or more, the effect of individual outliers on the final results is meaningful.

Rather than attempt to adjust results to account for this one data point, we prefer to rely on the DCF analysis in the record that avoids this problem entirely. Despite Northern's arguments to the contrary, we agree with Staff that Northwest Natural is appropriately removed from the proxy group on the basis of recent merger and acquisition activities. The screening criteria does not necessarily have nor does it require a *de minimis* exemption. Further, Northwest Natural's recent merger and acquisition activity during the period relevant to this case was not *de minimis*. *See* NUME-005-012. For these reasons, the Commission finds the Staff's DCF analysis to be more reliable as it neither requires adjustment of data nor includes data that may be considered an outlier. Nevertheless, we will address the results of the OPA's and the Company's analyses in our discussion below.

c. Return on Equity – DCF Model Results

Consistent with past Commission practice and orders, Mr. Hevert, Dr. Griffing and the Staff employed a discounted cash flow approach to the cost of equity analysis. The DCF model is commonly used for estimating the cost of common equity for public utilities and is based on the financial theory that the value or price of any security is the discounted present value of all future cash flows. As explained in materials published by the Society of Utility and Regulatory Financial Analysts:

> The DCF model is based upon two fundamental principles. First, DCF is based on the postulate that investors value an asset on the basis of the future cash flows (i.e., dividends and ultimate sales in the case of common stocks) they expect to receive from owning the asset. The second DCF principle is that investors value a dollar received in the future less than a dollar received today (i.e., the "time value of money"). Within their context, the current price of a company's stock is equal to the present value equivalent of the expected dividends and the proceeds from eventually selling the stock. The discount rate that equates the future anticipated dividends and the future anticipated selling price with the current market price is the cost of common equity.[42]

In its simplest form, a DCF estimate of the cost of equity capital uses the formula

K = D/P + g

where

K = the cost of equity capital;

D/P = the current dividend yield (the current dividend/current stock price); and g = the long-term expected growth rate.

Generally, the market-based data (market prices, current dividends and the resulting dividend yield) required to conduct any DCF analysis are readily available.

42 Parcell, David C., Society of Utility and Regulatory Financial Analysts, *The Cost of Capital—A Practitioner's Guide* 124 (2010 ed.) (*cited in* BA at 14).

As presented in his testimony, Mr. Hevert performed his DCF analysis using the current dividend and 30-day, 90-day and 180-day average closing stock prices as of May 17, 2019 and updated his analysis in rebuttal based on market information as of October 31, 2019. ROE Dir. at 55. He then calculated low, mean, and high results for each proxy company using, respectively, the minimum growth rate (i.e., the lowest of the First Call, Zacks, and Value Line earnings growth rates and an estimate of retention growth), the average growth rate from all four sources, and the highest of the growth rate from all four sources. ROE Dir. Exh. RBH-1; ROE Reb. Exh. RBH-1. As noted, Mr. Hevert's DCF proxy group and analyses include Northwest Natural and its Value Line earnings-per-share growth rate, which was 25.50% in his initial testimony and 27.00% in his rebuttal analysis. Mr. Hevert's updated Constant Growth DCF model results submitted in his rebuttal testimony ranged from 7.17% (mean low 30-day average) to 11.62% (mean high 180-day average). ROE Reb. at 58. Mr. Hevert supported an ROE range of 10.00% to 10.75% and recommended that the Commission approve an ROE of 10.50%. *Id.* at 57.

The OPA's consultant, Dr. Griffing, presented both a Constant Growth and a Multi-Stage Growth DCF analysis but accords no weight to the results of his multi-stage DCF, finding them to be below the bottom range of recent authorized ROEs. Griffing Dir. at 39–40. Dr. Griffing's Constant Growth DCF analysis for his comparison group produced a final mean ROE 9.04%. *Id*. at 30. Dr. Griffing did not update his DCF analysis in his surrebuttal testimony.

In its Bench Analysis, the Staff used a method similar in approach to the OPA and the Company, but with adjustments to reflect differences in the proxy group and input data. Most notably, as explained in Section V.C.1.c, Staff excluded Northwest Natural from its proxy group of companies. Staff's Constant Growth DCF model produced an indicated ROE range of 7.20% to 11.53% with an overall mean of 9.40%. BA at 18. The schedule did not call for a Reply Bench Analysis, so the Staff did not update its ROE analysis.

d. Return on Equity – CAPM Model Results

As the Commission has previously recognized, results from an analysis using the Capital Asset Pricing Model provide a useful check on the DCF analysis. *Central Maine Power Company, Proposed Increase in Rates*, Docket No. 92-345, Order at 31 (Dec. 14, 1993). The CAPM is a risk-premium approach

> that estimates the cost of equity for a given security as a function of a risk- free return plus a risk premium to compensate investors for the non-diversifiable or 'systematic' risk of that security. This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

ROE Dir. at 49. The general form of the CAPM is:

K = Rf + ß (Rm – Rf)

where

K = the required ROE;

Rf = the risk-free rate;

ß = the Beta coefficient of an individual security; and

Rm – Rf = the overall market risk premium.

The yield on Treasury securities is typically used for the risk-free rate.

In rebuttal, the Company presented a CAPM analysis using two sources for the risk-free rate: a current 30-day average yield on 30-year U.S. Treasury bonds of 2.18% and the average near-term projected 30-year Treasury yield for from Blue Chip Financial Forecasts of 2.28%. ROE Reb. at 59. For the Beta coefficient, Mr. Hevert used the Betas derived from Value Line and Bloomberg average of the Value Line Betas for his proxy group of 0.676 and derived an expected market return component of 15.25% based on the S&P 500 Index using the Constant Growth DCF formulation. ROE Reb. at 56–60 and ROE Reb. at 59. Mr. Hevert's CAPM calculations updated in rebuttal result in an indicated ROE range of 8.24% to 10.36%. *Id.*

In his testimony, Dr. Griffing employed a similar approach to the CAPM analysis with two notable variations. First, he used the average yield on a 30-year Treasury Bond for the period August 5–30, 2019 of 2.09% as his risk-free rate. Griffing Dir. at 34. Second, Dr. Griffing calculated his market rate of return similarly to Mr. Hevert, by applying a DCF formulation to the S&P 500. Notably, however, Dr. Griffing excluded from the S&P 500 universe any companies that do not pay dividends or have a negative or no value for an earnings growth rate. Both characteristics are essential inputs to the DCF model. *Id*. at 35. Dr. Griffing's CAPM analysis for his proxy group produced an ROE of 9.55%. *Id*. at 36.

Consistent with the Commission's preference as indicated in *Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design*, Docket No. 97-580, Order (Mar. 19, 1999), Staff's CAPM analysis also used a current 30-day average of the 30-year Treasury rate of 2.15% rather than a forecast of interest rates as the risk-free component. The Staff took a similar approach to Dr. Griffing in deriving its market risk premium, that is, by applying a DCF formulation to the S&P 500 but removing from the calculations any companies that do not comport with the assumptions underlying the DCF model. BA at 20–21. The Staff's CAPM analysis indicates an ROE range of 7.39% to 9.18%. BA at 21.

e. Return on Equity

As has long been our practice, the Commission relies on the DCF method and results to indicate an appropriate ROE. The Commission is cognizant of current equity- market conditions and the characteristics of different analytical tools used to estimate a company's cost of equity in a ratemaking proceeding and continues to have confidence in the DCF method. As noted, we have greater confidence in the Staff's Constant Growth DCF analysis, which produces an indicated ROE range of 7.20% to 11.53% with an overall average of 9.40%. The record evidence does not demonstrate that Northern's risk profile differs in any marked way from the risk profile of the proxy group upon which these results were determined, which would cause us to deviate from the mean determined in the Staff's analysis.

As a check to the DCF results, the Commission also considers the results of the CAPM analyses. As indicated, the Commission prefers the use of a current Treasury rate to a forecast of interest rates as the risk-free component in the CAPM analysis. The Commission finds the CAPM analysis provided by the OPA and the Staff to be more complete in that the market risk premiums used were based on sound DCF principles and the risk-free rate reflects current rates and not a forecast of interest rates. Dr. Griffing's CAPM analysis indicates an ROE value of 9.55% for his comparison group. Griffing Dir. at 36. Staff's CAPM analysis indicates an ROE range of 7.39% to 9.18%. BA at 21. The results of the CAPM analyses do not indicate the need to deviate from the results indicated by the DCF analysis.

As always, the determination of an appropriate ROE involves the exercise of judgment by the Commission. In this case, the Commission finds an ROE of 9.40%, which is well supported by the evidence in this case, to be reasonable. As Northern noted in its exceptions, it is appropriate to include an upward adjustment to account for flotation costs and no party contested the calculation of an eight-basis-point adjustment for flotation costs. Thus, we will increase the allowed ROE to 9.48%.

f. Capital Structure

In its brief, the Company affirms its request for a capital structure of 52.91% common equity and 47.09% long-term debt. Northern Br. at 36. The OPA concurs with Northern's initial request. OPA Br. at 33.

Northern claims that the common-equity ratio should more closely reflect its actual capital structure on December 31, 2018 after certain proforma adjustments and that the proposed structure "is consistent with Northern's financing goals and objective, and supports the financial profile required to ensure access to capital markets at competitive rates." Northern Br. at 37. The Company further explains that its credit metrics are "already strained as a result of its significant investment program and the associated regulatory lag" and because of the loss of bonus depreciation which resulted from the passage of the TCJA. Northern Br. at 39.

Staff disagreed with the proposed change in the common-equity ratio, noting that the equity ratios of the operating subsidiaries reflect regulatory, not investor, preference. Rather, it is appropriate to consider the capital structure of the entities for which market data is used—that is, the publicly traded parent companies. Unitil Corporation, Northern's publicly traded parent company and the source of equity capital invested into Northern, over a period of eight quarters (Q2 2017 to Q1 2019) has maintained a common-equity ratio consistently below 50%, ranging from 44.79% to 48.22% and averaging 46.44%. EXM-007-011, Att. 1.

Staff also provided an analysis of the common-equity ratios of the publicly traded parent companies in its proxy group, showing a range from 35.65% to 70.16% and an average of 53.22% as of year-end 2017 and 30.84% to 61.38% and average of 51.57% as of year-end 2018. BA at 24.

The Commission does not find sufficient evidence in the record to support a change in Northern's common-equity ratio. The evidence the Company provided reflects common-equity ratios of regulated operating subsidiaries of the proxy-group companies and, therefore, reflects regulatory preferences, not investor preferences. Northern's parent, Unitil Corporation, has maintained a common equity ratio in the range of 45% to 48%. Northern's rates have been set based on a capital structure that includes a 50% equity layer for several years. During that time, Northern has been able to maintain its credit rating and to attract capital. A 50% equity layer falls within the range established by the Company's witness, the OPA's witness, and the Staff's analysis, and, in the Commission's view, is the level that strikes the appropriate balance of meeting the *Hope-Bluefield Standards* and ensuring reasonable ratepayer costs.

g. Long-Term Debt Costs

In its initial filing, Northern proposed a cost of long-term debt of 5.49%, representing the Company's proforma net cost rate as of the test year. Exhibit CGDM-2, RevReq 6-4. In its Bench Analysis, Staff noted that the Company had completed the issuance of $40 million in long-term debt at a coupon rate of 4.04% in September 2019 and indicated that an updated cost of long-term debt should be used in calculating Northern's final weighted average cost of capital. BA at 22. In rebuttal, the Company incorporated this new debt issuance into its calculations, resulting in a 5.19% weighted average cost of long-term debt. Rev. Req. Reb. Exh. CGDM-1 and Exh. CGDM-1 (Rev. Jan. 15, 2020), Schedule RevReq 6-4. The Commission finds this updated cost of long- term debt of 5.19% to be reasonable.

h. Weighted-Average Cost of Capital

The determination of a 9.48% ROE with a 50% common-equity ratio combined with 50.00% long-term debt at a cost of 5.19% produces an after-tax WACC of 7.34% as shown in Figure 4.

Figure 4: Summary of Decision on Cost of Capital and Capital Structure

DESCRIPTION	WEIGHT	COST	WEIGHTED COST
Common Stock Equity	**50.00%**	**9.48%**	**4.74%**
Preferred Stock Equity	**—**	**—**	**—**
Long Term Debt	**50.00%**	**5.19%**	**2.59%**
Short Term Debt	**0.00%**	**3.62%**	**0.00%**
After-tax WACC	**100.00%**		**7.34%**

i. TIRA Rate of Return

As required by the Company's Targeted Infrastructure Replacement Adjustment, the calculation of a TIRA revenue requirement requires the establishment of a pre-tax WACC. *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 60 (Feb. 28, 2018). For purposes of calculating the TIRA revenue requirement, the pre-tax TIRA rate of return is set at 9.18%. The Company shall use an ROE of 9.48% for purposes of applying the TIRA Earnings Sharing Mechanism.

D. Overall Increase in Revenue Requirement

Considering all of the above adjustments, the Commission approves an increase of $3,605,412, or 7.5%, over Northern's current weather-normalized revenues. The calculations supporting this figure are detailed in Appendix A to this order. The main driver of this rate increase is the increase to the Company's rate base since its last general rate case.

VI. RATE DESIGN

A. The Company's Proposal

The Company's proposed inter-class revenue allocation and rate design were based on the testimony of its witness Mr. Paul Normand, a consultant with Management Applications Consulting (MAC). Mr. Normand's testimony and recommendations were based on two cost-of-service studies: an accounting, or embedded, cost-of-service (ACOS) study, and a marginal-cost-of-service (MCOS) study.

Mr. Normand reached two primary conclusions from the studies: first, that customers in the residential rate classes are subsidized by other customers; and second, that most of the costs to provide distribution service are fixed and, thus, should be recovered through fixed charges rather than volumetric charges. However, in recognition of other rate design considerations, such as rate stability, Mr. Normand applied his judgment to the study results and recommended class-revenue allocations and changes in rate design that move in the direction indicated by the studies, but not to the full extent indicated. Specifically, Mr. Normand proposed capping the overall revenue percentage increase to the Residential (R-2) and Low Annual / High Winter Use (G-40) classes at 125% of the overall company average, or 18.99% (15.19 × 1.25) based on the Company's direct case, even though he contended that the cost-of-service studies support a larger increase. He allocated the remaining revenue requirement to the other classes based on their respective revenue requirements at the Company's overall rate of return.

With regard to intra-class rate design, the Company proposed to increase the fixed monthly charge by the same percentage as the Company's overall increase. The Company allocated the remaining class revenue requirement to the existing block structure to maintain the existing block differentials.[43]

B. Positions of the Parties and Staff

1. The OPA

Through the testimony of its expert witness, Mr. Jerome Mierzwa, the OPA reached several conclusions about the Company's rate design proposals. First, the OPA agreed that the accounting cost-of-service study presents a reasonable indication of the cost to serve the various customer classes and concluded that the allocation of revenues among the customer classes is reasonable. Mierzwa Dir. at 3. The OPA did not agree with the findings of the MCOS study and therefore argued that it should not serve as the basis for setting rates in this proceeding. The flaw in the MCOS study, according to the OPA, is that costs are assigned to the various customer classes based on each class's design-day demand (that is, the demands that are expected under the most severe weather assumptions). Mierzwa Dir. at 9. According to the OPA, design-day usage is less than 1% of the annual usage of Northern's customers and the Company's investment decisions are based on the need to provide reliable service every day, not just on peak days. Mierzwa Dir. at 10–11. In support of this claim, the OPA observed that even though Northern added mains to serve new customers every year between 2001 and 2012, the peak-day capacity declined in five of those years. Mierzwa Dir. at 10–11. The OPA indicated that an even allocation of the increase authorized in this proceeding would be reasonable. Mierzwa Reb. at 2.

In its brief, the OPA discussed the Staff's position in the Bench Analysis in support of a higher fixed monthly charge. The OPA stated that, under the cost-causation principle, utility costs should be allocated to those customers that cause a utility to incur those costs. OPA Br. at 45. Northern's decisions to extend distribution mains, install

43 The rates for each of Northern's rate classes include a fixed monthly customer charge and two volumetric rate blocks—a head block and a tail block. One dollar-per-therm rate applies to the head block, which consists of a delimited number of therms (which varies by rate class) beginning with the first therm consumed. Another dollar-per-therm rate applies to the tail block, which consists of all usage beyond the limit of the head block. The block differential is the dollar difference between the head-block and tail-block rates.

service lines, and incur the expenses related to those investments, are based on a net present value (NPV) test. If the NPV is less than zero, the Company is not obligated to extend its distribution mains or service lines without a contribution in aid of construction (CIAC). The OPA argued that, because customers with higher usage will generate a higher NPV, a higher-use customer will cause Northern to incur greater investment. OPA Br. at 46. The OPA argued that this supports its position that costs of providing utility service are not equally imposed on Northern by higher- and lower-usage customers, and that the Commission should reject Staff's position that cost of service is largely fixed and a higher fixed charge might be appropriate. OPA Br. at 46. In addition, the OPA contended that a higher fixed charge lessens the connection between what a customer uses and what customers pay for that usage. OPA Br. at 48. In the OPA's view, that is inconsistent with Maine's energy conservation and efficiency objectives.

2. Staff's Position

In the Bench Analysis, the Staff expressed concern about the Company's proposal to increase the residential and low annual/high winter class revenue requirement by 1.25 times the overall average increase. In Staff's view, depending on the level of the overall increase approved, such an increase could be unduly burdensome to those classes, especially when viewed in the context of the TIRA increases which have increased rates 4.5% over the last two years and which are expected to continue to increase rates annually through 2024. BA at 50–51. Staff generally agreed with the conclusions in the cost-of-service studies that the cost of the distribution system is largely fixed and observed that rate-design components such as class allocation involves exercising a significant amount of judgment. BA at 51.

With regard to intra-class rate design, in the Bench Analysis the Staff was not convinced that the Company's proposal was consistent with the results of the cost-of- service studies. BA at 52. Specifically, Staff observed that Northern's proposal to maintain a constant dollar-per-therm differential between the usage blocks lacked support or explanation and appeared to conflict with the Company's position that distribution costs are largely fixed and do not vary with usage since it would result in higher than average increases for higher than average users. BA at 52. Finally, Staff said that it could support a relatively higher increase to the customer charge compared to the usage charges given the fixed nature of distribution costs.

Ultimately, in the Examiners' Report the Staff recommended that the rate increase apply evenly across all rate classes and rate elements.

3. The Company's Response

The Company argued that its proposed changes in rate design were consistent with the results of the ACOS and MCOS studies. Northern Br. at 137–40. Northern disputed the OPA's claim that higher-use customers will incur a greater cost to serve. Northern Reply Br. at 39. The Company also argued that there is no statute or policy in Maine requiring that energy conservation be achieved by manipulating a utility's rate design. Northern Reply Br. at 40. Instead, according to the Company, its proposal set cost-based rates that would send the proper price signals to customers to allow them to make informed and economically efficient decisions about their energy usage. Northern Reply Br. at 41.

In response to the Staff's Bench Analysis, the Company appeared to argue that the existing block-rate differentials are reasonable because the proposed fixed charge is less than what the cost-of-service studies would indicate and, therefore, increasing the tail block by a higher amount reflects a move toward cost of service in the aggregate for higher-use customers. Rate Design Reb. at 2.[44] According to the Company, when applied to the residential class, this result concentrates the inter-class revenue allocation subsidy to the lower-use customers. Rate Design Reb. at 3.

C. Discussion and Decision

The Company presented two cost-of-service studies to support its rate design proposals. Through its ACOS study, the Company concluded that the residential and low annual/high winter use customers are significantly subsidized by the other rate classes. Through its MCOS study, the Company concluded that the costs to serve customers are largely fixed and do not vary much by usage level. The Commission accepts these general conclusions and finds them useful in guiding decisions on rate design. Rate design is not, however, simply a mathematical exercise, nor are cost-of- service studies perfectly precise. While these studies are informative, the results they indicate must be balanced with other considerations, including equity, rate stability, and customer acceptance. Stated another way, since changes in rate design inevitably create benefits for some and detriments for others, proposed changes in rate design require that the Commission exercise substantial judgment.

With respect to the inter-class revenue allocation, the Company proposed to increase residential and low annual/high winter use customer revenue by 125% of the total overall increase. This was meant to decrease the inter-class subsidies that the Company argued are indicated by the ACOS. The OPA supported this approach. Mierzwa Dir. at 3. The Commission agrees with the Staff that any increase to a class's revenue allocation—such as would be imposed on residential and low annual/high winter use customers by the Company's proposal—must be considered in the context of other rate increases facing these customers. Under the Company's proposed overall revenue requirement increase and revenue allocation, base rates for customers in these classes would increase by approximately 19%, on average. Given the Commission's decision on the overall revenue-requirement increase for Northern, the Company's proposed revenue allocation would increase base rates for its residential and low annual/high winter use customers by approximately 9.5%. This increase would be in addition to the annual rate increases that have been implemented over the past several years under the TIRA, which cumulatively have increased rates by 4.5% since the

44 The pages of Mr. Normand's rebuttal testimony are not numbered. The citations to this testimony count from the first page of the testimony, excluding the cover page and table of contents.

Company's last base-rate proceeding (which concluded in early 2018), and the TIRA increases that will occur over the next several years, which could cumulatively increase rates by 2025 by as much as 26%.[45] Added to these increases is the potential for another increase related to the CIS after the completion of the audit discussed in Section V.B.3.c.ii. Given all of these increases, past and future, the Commission finds that additional increases from changes to revenue allocation among rate classes would be overly burdensome to residential and low annual/high winter use customers.

As for intra-class rate design, the Company proposed increasing the customer charge by the same percentage increase as approved for the Company overall and designing the usage charges to collect the remaining rate class revenue in a way that maintained the existing block differentials. Figure 5 below summarizes the proposed rates and percentage changes for several rate classes that would result from the Company's proposed revenue requirement and rate design.

Figure 5: Northern's Proposed Increases to Rate Elements, by Class[46]

Rate Component	Rate Increase Current Rate	Proposed Rate	% increase
Residential Heating (R2)			
Customer Charge	$ 26.20	$ 30.18	15.19%
Distribution Charge – First 40 thm	$ 0.4762	$ 0.5670	19.07%
Distribution Charge – Excess 40 thm	$ 0.3495	$ 0.4403	25.98%
General Service – Low Annual, High Winter use (G40)			
Customer Charge	$ 62.22	$ 71.67	15.19%
Distribution Charge – First 70 thm	$ 0.3187	$ 0.3818	19.80%
Distribution Charge – Excess 70 thm	$ 0.2840	$ 0.3471	22.22%
General Service – High Annual, High Winter use (G42) – Winter Rate			
Customer Charge	$ 1,050.52	$ 1,210.14	15.19%
Distribution Charge – First 18,000 thm	$ 0.2805	$ 0.3042	8.45%
Distribution Charge – Excess 18,000 thm	$ 0.2364	$ 0.2601	10.03%
General Service – High Annual, High Winter use (G42) – Summer Rate			
Customer Charge	$ 1,050.52	$ 1,210.14	15.19%
Distribution Charge – First 6,000 thm	$ 0.2346	$ 0.2583	10.10%
Distribution Charge – Excess 6,000 thm	$ 0.1925	$ 0.2162	12.31%

45 The annual cap on the TIRA increase is 4% of base-rate revenues. This 26% figure is calculated as the maximum possible increase to rates (4% per year) compounded annually over the remaining six TIRA cases, which will occur in years 2020–2025 (for investments made in years 2019–2024 respectively).

46 BA at 52, Fig. V.C (citing Rate Design Dir. Exh. PMN-1G-8).

The Commission finds the Company's positions on intra-class rate design inconsistent and lacking in support in several regards. First, the Company argued that its proposal improves pricing efficiency by moving prices toward higher fixed costs and thus reducing the amount of fixed costs recovered through volumetric charges. Northern Br. at 139. However, the Company has not proposed to increase fixed charges by more than the percentage amount of its proposed increase in the overall revenue requirement (15.19%). Indeed, as shown above in Figure 5, for certain classes, the Company's proposed rate design appeared to have the opposite effect of moving toward greater recovery of its costs through fixed charges. For example, for its residential heating class, the Company's proposed rate design would actually *increase* the extent to which its costs are recovered through volumetric charges.

The Commission finds the Company's proposal to maintain the existing rate block differentials similarly lacking in support. The Company explained that, in maintaining the existing block differentials, the "variances in % change in rate components are due to mathematics resulting from the Company's [method] used to design its proposed rates." Northern Br. at 142. While that much is obvious, it is not obvious why maintaining the existing block differentials is necessary or desirable.

The Company also argued that customers with higher usage do not cause Northern to incur greater costs than a customer with lower usage. Northern Reply Br. at 39.[47] However, the Company's proposed rate design changes seem at odds with that stated position. For example, in rebuttal the Company stated that

> [t]he proposed rate levels reflect a move [toward] cost of service for the higher use customers. By moderating the customer charge and head block while maintaining the existing block differential, the resulting tail block [received] a higher percent increase but is much more reflective of costs . . . . [A]s a result, the proposed approach to these rate components moves the larger customer usage to cost of service and minimizes any subsidies for the higher use volumes.

Rate Design Reb. at 2–3. Although this might be true as a matter of math, it conflicts with the assertion that distribution costs are largely fixed. Moreover, why it is preferable for inter-class subsidies to be limited to certain customers in a given class is unclear.

As to the OPA's argument to retain the monthly residential customer charge at its current level to support efforts related to energy efficiency, the Commission finds that this approach—which, in effect, would increase charges for relatively higher-use customers by more than charges for relatively lower-use customers—is not supported by the cost studies in evidence in this proceeding. Moreover, for the reasons discussed above, it would result in unduly burdensome increases for higher-use residential customers when considering annual rate increases over the past several years and the next several.

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47 Northern states that the "OPA posits that 'a customer with a higher usage level will be eligible for and will cause Northern to incur greater investment and other costs than a customer with lower usage.' This is not accurate." Northern Reply Br. at 39 (internal citation omitted).

For all of the reasons discussed above, the Commission rejects the Company's rate design proposal as well as the OPA's proposal to keep the residential customer charge at its current level. Given the other rate increases over the past and next several years, the Commission finds that it would be overly burdensome to impose additional increases on any subset of Northern's customers. Therefore, the Commission directs the Company to apply the overall rate increase on the same percentage basis to all rate classes and rate components.

VII. PROPOSED CAPITAL INVESTMENT RECOVERY ADJUSTMENT

A. The Company's Proposal

In the testimony of Messrs. LeBlanc, Sprague, and Goulding, Northern proposed that the Commission authorize adoption of a new capital tracker, which it named the capital investment recovery adjustment, or CIRA. According to the Company, the CIRA would enable faster recovery of capital investments that are mandated by governmental entities or for public-safety reasons. The CIRA would permit Northern annual recovery of investments in the following five categories:

1. Relocation of Gas Facilities (government- and public-safety-mandated). This includes facility relocations driven by state and municipal construction projects, including, for example, road construction, sewer separation, and relocation of pipes from aboveground locations to underground. Because its facilities are located in state or municipal rights of way, Northern has little or no discretion in these relocation requirements. Northern Br. at 81 (citing Ops. Dir. at 23–28).

2. Abandonment of Gas Services. Section 6(C) of the Commission's gas safety rule (Chapter 420) requires natural-gas local distribution companies like Northern to disconnect and abandon natural-gas service lines within two years or five years (depending on the type of pipe) of natural gas no longer being billed to the customer. This is a nondiscretionary, safety-related cost. Northern Br. at 83–84 (citing Ops. Dir. at 28–30).

3. Gas-Meter Replacement. From time to time Northern needs to remove meters from service. Meters that are still in good working condition may be refurbished, tested, and placed in meter inventory for return to service; meters that are no longer in good working condition may be retired and replaced with a new meter. The CIRA would include the cost of replacing meters. Northern Br. at 84 (citing Ops. Dir. at 30–31).

4. Regulator-Station Overpressure-Protection Redundancy. Northern intends to recover through the CIRA the cost of installing additional overpressure protection at its existing regulator stations. This work is being done in response to Northern's assessment of possible overpressure-protection improvements that could be made following the Merrimack Valley distribution-system overpressurization event in September 2018, among the worst natural-gas disasters in U.S. history. Northern Br. at 83 (citing Ops. Dir. at 31–32 and Tr. at 146 (Jan. 22, 2020 Hr'g)).

5. Second-Year Pavement Restoration. When Northern performs construction within a state or municipal right of way, it must restore any paved areas disturbed during construction. This is a nondiscretionary cost. In general, for open-trench installations, second-year paving accounts for about 15% of the total project cost. Northern Br. at 83 (citing Ops. Dir. at 32–33).

Northern explained that the “CIRA is similar to, and shares common elements with, the Company’s TIRA,” or targeted infrastructure replacement adjustment. Ops. Dir. at 17. It would be in place for “an initial three-year term,” and would share the 4% cap on annual adjustments that is already in place for the TIRA, meaning that the combination of the TIRA and the CIRA could not exceed 4% in any given year.[48] Ops. Dir. at 17–18. CIRA expenditures could, however, be carried over from year to year if they would otherwise exceed the cap. Ops. Dir. at 18. The CIRA would also be subject to the earnings-sharing mechanism already in place for the TIRA. Ops. Dir. at 17.

The Company’s principal argument for the CIRA was that natural-gas utilities like Northern face the pressure of increases in non-revenue-producing, non-growth- producing investments, and that having the CIRA in place would help prevent continued earnings erosion the Company faces. Ops. Dir. at 15, 20. According to the testimony of Mr. Lyons and Ms. Nelson, adoption of the CIRA would help Northern address earnings erosion by providing Northern with “a stable stream of revenues to fund non-TIRA, non- growth-producing” investments; funding safety- or otherwise-mandated investments; and “streamlin[ing]” the cost recovery process. Earnings Dir. at 35–38; *see also* Ops. Dir. at 15. Mr. Lyons and Ms. Nelson compared Northern’s authorized ROE with its earned ROE in each year from 2014 through 2018, finding that “the Company under- earned its authorized ROE by nearly 220 basis points, on average” annually over that period. Northern Br. at 79 (citing Earnings Dir. at 17, Table 5). The primary cause of this decline was asset turnover, “indicating that the Company experienced diminished efficiencies in its assets because increases in revenues did not keep pace with increases in capital expense.” Northern Br. at 79 (citing Earnings Dir. at 18–19). According to the Company, it would not be possible to offset the increase in capital expense with savings; “[t]o achieve its allowed return during 2017 through O&M savings, Northern would have had to reduce costs by nearly half.” Northern Br. at 79 (citing Earnings Dir. at 23, Fig. 8).

48 The TIRA provides for annual recovery of costs of the Company’s cast-iron replacement program (CIRP), unprotected steel (UPS) replacement program, and farm tap (FT) replacement program. Ops. Dir. at 9–10. Costs are only recoverable if they meet certain targets set in an earned value management (EVM) program tool. *See* Ops. Dir. at 10–11. The TIRA investments are scheduled to be completed in 2024. Ops. Dir. at 11.

B. Positions of the Parties and Staff

1. The OPA's Position

In his testimony analyzing Northern's revenue requirement, Mr. Morgan, witness for the OPA, testified that the "CIRA will have a very minimal effect on reducing earning erosion and is not likely to reduce frequent rate cases." Morgan Dir. at 16. Mr. Morgan was also concerned that adoption of the CIRA would make it more likely that the Company would seek to increase the annual cap above 4%—especially given the Company's past advocacy for an increase in the TIRA cap, to 5% from 4%. Morgan Dir. at 16–17 (citing Docket No. 2017-00065, Direct Testimony of David L. Chong at 43:8–18). Mr. Morgan recommended that the Commission not authorize the CIRA because it would "only provide another mechanism to allow annual rate increases without examining other cost changes." Morgan Dir. at 18.

In its brief, the OPA argued against the CIRA for several reasons. First, the amounts Northern proposed to include in the CIRA "are minor by comparison to other components of [its] non-growth capital expenditures." OPA Br. at 15. According to the OPA, "as a percentage of Northern's total non-growth costs, those costs proposed to be included in the CIRA are declining, remaining in the range of $4.2 million annually, while other project costs are increasing." *Id.* Second, the relatively small amount of capital spending under the CIRA made it "unlikely that it would decrease the frequency of Northern's rate filings." *Id.* at 16. Third, the OPA expressed concern about whether Northern would be able to keep its overall annual spending on TIRA and CIRA projects under the 4% cap, and the fact that CIRA-related investments would be deferred for recovery if they exceeded the cap—which is seemingly inconsistent with the idea of a cap. *See id.*

And finally, the OPA supported the Staff's position as laid out in the Bench Analysis (described below) that there are policy reasons to reject the CIRA. *Id.* at 17–21.

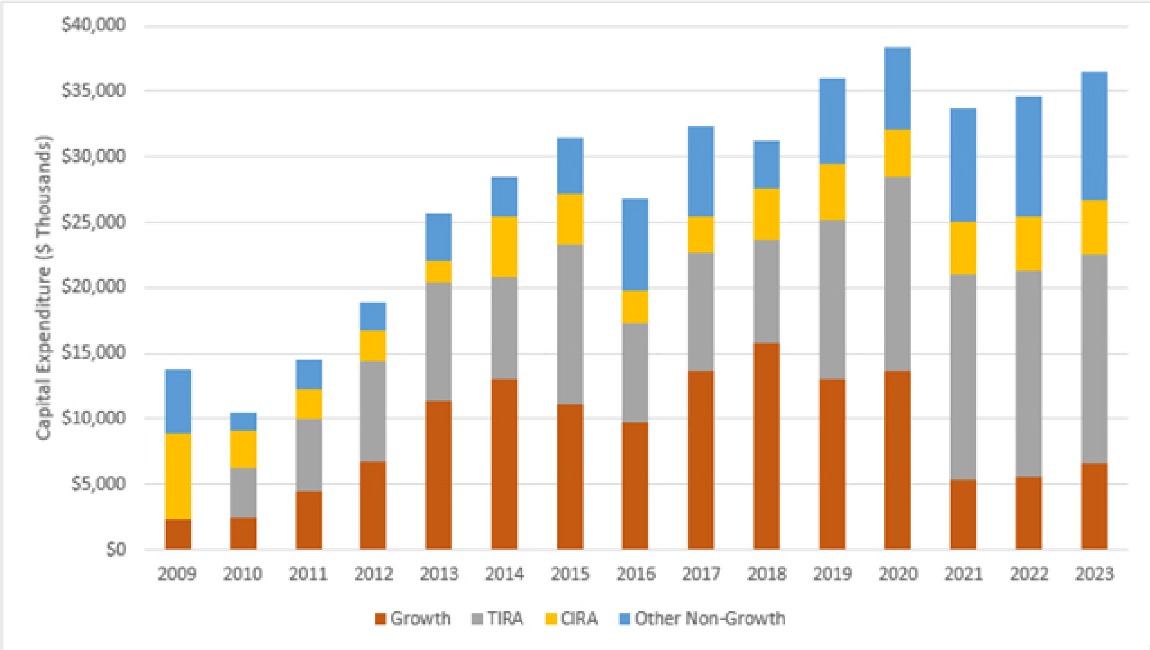
2. Staff's Position

In the Bench Analysis, the Staff agreed with Mr. Morgan in rejecting the Company's proposed CIRA. According to the Staff, the CIRA, which would allow certain categories of costs to be separated out for discrete cost recovery, would be contrary to the general practice of matching costs and revenues. The Staff argued that "capital trackers should be reserved for extraordinary—and generally nonrecurring— circumstances." The Staff pointed to the TIRA as an example of an appropriate use of a capital tracker: the TIRA was prompted by the need for Northern to make extraordinary and accelerated capital investments in the replacement of its cast-iron and unprotected- steel pipes and (eventually) its farm-tap regulators. These replacement programs have a defined end date, thus ensuring a defined end to the TIRA. BA at 56.

According to the Staff, the cost-categories that would make up the CIRA consisted of ordinary investments of a natural-gas utility. Thus, it was not clear to the Staff why the categories of expenses proposed for inclusion in the CIRA should not be treated the same as all other standard utility expenses and investments. BA at 55–58.

The Staff also agreed with Mr. Morgan that the capital expenditures Northern has proposed including within the CIRA mechanism were relatively consistent from year to year and relatively small in amount. The CIRA-related expenses were only about 10% of the Company's average annual capital investments.[49] In this way, the CIRA did not consist of the kind of extraordinary capital expenditures that might justify a capital tracker. To illustrate the proportion of CIRA-related expenditures in relation to Northern's capital investments overall, the Staff presented the following figure:

Figure 6: CIRA Expenditures as a Portion of Northern's Overall Capital Investments, 2009–2023[50]



BA at 58.

The Staff also asserted that the CIRA was not as similar to the TIRA as the Company claimed. BA at 58–60. Unlike the TIRA, the proposed CIRA offers no way to evaluate whether the Company's CIRA investments reflect cost-effective investment levels, nor does the proposed CIRA include any features that would create incentives for the Company to make those investments efficiently. With the TIRA and the associated investments in the cast-iron replacement program, unprotected-steel

49 This percentage is based on the data provided in EXM-008-004 and excludes from the CIRA totals growth-related second-year asphalt restoration as shown in ODR-001-019.

50 BA at 58; EXM-008-004. The CIRA amount shown here includes some growth-related asphalt restoration. *See* Tr. at 87–88 (Aug. 28, 2019 Tech. Conf.).

replacement program, and farm-tap replacement program, the Commission has approved a TIRA structure that establishes metrics against which to evaluate the Company's performance on project cost and schedule. The metrics are derived from Northern's earned value management (EVM) model, and if the metrics set for that model are not met, the Company's TIRA investments will not be fully recovered through the TIRA adjustment. Under the proposed CIRA, the Staff argued, there is neither an EVM nor a similar tool that the Commission could use to evaluate the efficiency of the Company's work.

According to the Staff, Northern's claim that the CIRA would reduce the need for general rate cases was unsupported. BA at 60. Northern argued that, without the CIRA, it will be forced to file rate cases more frequently. Ops. Dir. at 15. When asked how long the duration between rate-case filings would be with the CIRA versus without it, the Company stated that it had not done that analysis. Tr. at 68 (Aug. 28, 2019 Tech. Conf.). According to the Staff, this created the possibility that, even with the CIRA in place, the pace of general rate cases would not change.

The Staff rejected Northern's claims that, even if a CIRA rate case took the full eight months to process, it would be less work-intensive than a general rate case. EXM-008-018. There was no quantification of the amount of time and effort that may be necessary, and, according to the Staff, it is possible that a rate case focused on a small handful of issues could become controversial and demand a similar amount of resources as a general rate case. BA at 61.

The Staff also posited that it appeared that one motivation for the CIRA was to allow Northern to take full advantage of the 4% cap on spending that is already in place for the TIRA. BA at 61–62. Under the Company's estimates, the allowed rate increase under the 4% TIRA cap and the total incremental TIRA and CIRA revenue requirement were nearly identical. The Staff countered Northern's position by stating that the 4% cap was carefully crafted and approved for the TIRA; it was not contemplated for the CIRA, and thus should not be added to that cost-recovery mechanism.

In the Examiners' Report, the Staff's position was essentially unchanged.

3. <u>The Company's Response</u>

In its rebuttal and its post-hearing brief, Northern continued to advocate for establishing the CIRA to help it combat earnings erosion, going so far as to say that rejecting the CIRA would be "unduly punitive." Northern Br. at 6. Northern stated that it demonstrated that traditional ratemaking is not giving Northern an opportunity to earn its allowed return, and, if it were, Northern "would have no need for the proposed CIRA. Staff's argument completely ignores the Company's analyses and misses the Company's fundamental point." *Id.* at 92.

Northern asserted that the CIRA-related investments would provide meaningful relief, and that, had the CIRA been in place from 2014 through 2018, it would have increased the Company's actual returns by nearly 50 basis points per year. Ops. Reb. at

3; Northern Br. at 86 (citing Earnings Reb. at 5), 89. Northern emphasized that in none of those years has it earned its authorized ROE, and that the CIRA was "not expected to produce a 'windfall'" for its shareholders, but rather would "provide a safety net against severely deficient ROEs." Northern Br. at 86.

Northern argued that the amount of analysis the OPA and Staff provided to support their criticism of the CIRA was minimal if it was done at all, while the Company presented multiple pieces of testimony in support of the proposal. Northern Br. at 88–89.

The Company disagreed with the Staff's position on approval of capital trackers and argued that the CIRA complied with the matching principle. As a way of describing the CIRA's compliance with the matching principle, Northern pointed to the TIRA's O&M offset, which is meant to reflect "the fact that the Company should experience reduced O&M expense as leak-prone mains are replaced and fewer leak repairs are necessary." Ops. Reb. at 6. The cast-iron and unprotected-steel replacement programs in the TIRA "are not growth-related, and therefore the TIRA does not account for revenue growth." Ops. Reb. at 6. As for the farm-tap regulators, Northern described those as being "not prone to leaks" and therefore the TIRA did not include an O&M offset for their replacement. *Id.* at 6. Northern posited that, as thus described, all three elements of the TIRA are consistent with the matching principle. Northern argued that this same reasoning supported the CIRA's consistency with the matching principle: "none of the CIRA-eligible investments result in customer growth or O&M savings," and thus there is no O&M offset in the proposed CIRA. Ops. Reb. at 7.

Northern also criticized the Staff's description of the matching principle as demanding that aggregated costs be matched with aggregated revenues, arguing that the very existence of the TIRA would violate the matching principle if that were the standard. Northern Br. at 90–92.

Northern argued that the Staff "crafted" a standard in the Bench Analysis requiring that capital trackers, to be approved, must be "extraordinary" in nature. Ops. Reb. at 7–8. Northern criticized the "lack of definition of 'extraordinary'" as making "it impossible to determine what projects meet Staff's test." Ops. Reb. at 8. Northern pointed to the farm-tap regulator program as a counterexample to Staff's claim that the TIRA is a "perfect example" of an extraordinary and generally nonrecurring expense for a capital tracker. Ops. Reb. at 8. According to Northern, "the original estimated cost to replace all of the approximately 103 farm taps was only $1.3 million and the combined cost of all three [TIRA] projects was $74.4 million," so the farm-tap program in the TIRA does not seem to meet the Staff's "extraordinary" standard. Ops. Reb. at 8.

Northern emphasized the similarity of the CIRA and the TIRA, arguing that the CIRA projects are no more (or less) a cost of doing business than the TIRA projects and that all of the investments in both the TIRA and the CIRA are safety-related or government-mandated costs of doing business. Northern Br. at 90–92.

The Company also argued that it had no plan to request an increase in the 4% cap during the term of the CIRA, Ops. Reb. at 3–4, and that it did not cherry-pick projects to include in the CIRA to optimize the 4% cap in place for the TIRA. Ops. Reb. at 14–15.

Northern described Staff's doubts about the administrative efficiency of the CIRA as a "red herring," and said that "[o]ne thing is certain . . .: without the CIRA the Company will . . . need to file for a base rate increase sooner than it would without the CIRA." Ops. Reb. at 9–10, 10–13; *see also* Northern Br. at 92–94.

C. Discussion and Decision

For the reasons set out below, the Commission rejects the Company's proposal to establish the CIRA.

1. Traditional Ratemaking

As a general rule, utilities seek rate changes by filing general rate cases with the Commission. These cases involve a review of all of the Company's costs of doing business—O&M expenses, capital investments in rate base, and the return on that rate base—and offsetting revenues. Pulling certain categories of costs out of these traditional revenue-requirement reviews for special treatment is disfavored because it is contrary to the general practice of matching costs and revenues. *See Re Camden and Rockland, Maine and Wanakah Water Companies*, Docket No. 93-145, Order (Part II) at 5, 6 (July 12, 1994) (describing the matching principle). It makes it harder, if not impossible, to match sales and revenues with costs and investments, which diminishes the ability of the Staff and parties—and ultimately the Commission—to evaluate and consider the justness and reasonableness of the utility's proposed rates in any given case. *See Central Maine Power Company, Request for New Alternative Rate Plan ("ARP 2014")*, Docket No. 2013-00168, Order of Partial Dismissal at 7 (Aug. 2, 2013) (rejecting proposal for capital expenditure recovery mechanism because it would "create a mismatch of cost and savings that is contrary to general regulatory ratemaking principles" and because its "fully reconcilable nature . . . for which accurate costs are lacking . . . undermine the Commission's goal of predictability, stability, and comprehensiveness in setting . . . rates").

The Commission has the discretion to approve alternative ratemaking mechanisms for natural-gas utilities. *See* 35-A M.R.S. § 4706. The Commission agrees with the Staff that capital trackers should be reserved for extraordinary—and generally finite and nonrecurring—circumstances. The TIRA is one such example. The TIRA was prompted by the need for Northern to make extraordinary and accelerated capital investments in the replacement of its cast-iron and unprotected-steel pipes and farm-tap regulators. These replacement programs are expected to be completed in 2024, thus ensuring a natural end date for the TIRA. *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Targeted Infrastructure Replacement Adjustment Rate*, Docket No. 2019- 00042, Order at 1 (Apr. 17, 2019). Part of the justification for the TIRA was that it provided Northern certain benchmarks for completing the critical safety improvements of the CIRP more quickly than otherwise possible. *See* Tr. at 78–79 (Nov. 26, 2019 Tech. Conf.). Thus, a capital tracker might be "extraordinary" not just in terms of the cost of the investments subject to it but also in terms of the circumstances surrounding the investments.

Here, the CIRA consists of ordinary investments of a natural-gas utility. Thus, it is not clear why the categories of expenses proposed for inclusion in the CIRA should not be treated the same as all other standard utility expenses and investments. Any natural- gas utility has an ongoing obligation to relocate its facilities on a government entity's request. This is a cost of doing business, not an extraordinary or unusual expense. The same goes for abandonment of gas services (required by Commission rule), gas-meter replacement (required to remain in compliance with Commission rule), and second-year pavement restoration (required by municipal ordinance and the Maine Department of Transportation). As for overpressurization protection and public-safety-mandated (but non-government-mandated) relocation of gas facilities, it is within the Company's discretion as system operator to decide whether and how those investments are appropriate to undertake. Again, these ongoing safety measures are a typical utility business expense. The fact that they are non-revenue-producing does not make them any better suited to a capital tracker and annual recovery in a special, separate rate increase. In the Commission's view, a capital tracker is an exception to traditional ratemaking approaches and should be reserved for exceptional costs or initiatives, such as those required by the cast-iron replacement program.

Northern makes much of the Staff's statements that capital trackers are reserved for "extraordinary" and "non-recurring" expenditures and criticizes the Staff's refusal to adopt a bright-line definition or test for what qualifies as "extraordinary." These arguments do not persuade the Commission; in legal interpretation, and certainly in Commission precedent, it is often the case that one cannot easily define a standard for approval with a bright-line test. Instead, every proposal is viewed on its own merits, in its own context, and with an eye toward achieving the best and most reasonable outcome for the Company and its customers under the law. It remains the case that the Commission views proposals for capital trackers skeptically due to the general preference for traditional ratemaking mechanisms. The Commission is unlikely to approve adoption of capital trackers for the kind of investments a utility is expected to undertake from day to day or from time to time. Investments with foreseeable end dates are more likely to be suitable for capital trackers.

Northern argued that the inclusion in the TIRA of the cost for replacing farm-tap regulators renders Staff's "extraordinariness" test invalid. The Commission is willing to concede that, standing alone, had the farm-tap regulators been proposed for recovery in their own capital tracker, it is not obvious the proposal would have been approved. The context in which the replacement of farm-tap regulators was added to the TIRA was perhaps unexpected: the Company's TIRA proposal was already on the table when Chapter 420 was amended in a way that subjected only Northern to yet another safety- related replacement program. The farm-tap regulators that Northern now needed to replace were definite in number (rather than unknown) and the timeline for their replacement was relatively easy to determine and finite (rather than unending). The TIRA presented a convenient way to recover those mandated costs that were unique to Northern, and thus were added to the TIRA in a stipulated result in the Company's 2013 rate case. *Northern Utilities, Inc. d/b/a Unitil, Proposed Base Rate Increase and Rate Design Modification*, Docket No. 2013-00133, Order Approving Stipulation at 3, 5, 8 (Dec. 27, 2013). It would not be wrong to describe this facet of the TIRA as "borderline" for inclusion in a capital tracker. Tr. at 75, 76 (Nov. 26, 2019 Tech. Conf.). But that fact does not mean that anything goes when it comes to capital trackers, and it does not render meaningless the Commission's general skepticism of capital trackers. *See Central Maine Power Company, Request for New Alternative Rate Plan (ARP 2014)*, Docket No. 2013-00168, Order of Partial Dismissal at 5–8 (Aug. 2, 2013).

The Company's arguments in favor of the CIRA were similar to the arguments it set forth in favor of using year-end rate base—principally, the problem of earnings erosion due to the ongoing and growing need to make non-growth-producing investments. As explained above in Section V.B.1.c, the Commission has in this case approved Northern's request to set rates using year-end rate base. The Commission expects that this will help address the earnings-erosion (attrition) issues that prompted Northern to propose the CIRA. Where ratepayers are on the hook for increased costs, it is in the public interest to address concerns about earnings attrition incrementally, rather than piling on sources of rate increases through multiple methods, if it can be avoided.

2. Key Differences from the TIRA

The Company claimed that the CIRA "is similar in mechanics" to the TIRA and explains that the CIRA "shares both a cap on base rate adjustments and an Earnings Sharing Mechanism ('ESM') with the Company's TIRA Tariff." Earnings Dir. at 35, 38; Ops. Dir. at 16. But there are critical differences between the TIRA and the CIRA. Most importantly, the proposed CIRA offers no way to evaluate whether the Company's CIRA investments reflect efficient and cost-effective investment levels. Nor does the proposed CIRA include any features that would create incentives for the Company to make those investments efficiently. With the TIRA and the associated investments in the cast-iron replacement program, unprotected-steel replacement program, and farm-tap replacement program, the Commission has established metrics against which to evaluate the Company's performance on project cost and schedule. The metrics are derived from Northern's EVM, which is "used to track complicated construction projects based on the project scope, cost and schedule that are each estimated prior to the commencement of project construction." Ops. Dir. at 10–11. The EVM-based cost and schedule metrics establish benchmarks to evaluate the Company's performance in implementing the TIRA programs. By its design, the TIRA provides incentives for the Company to meet these metrics; if not met, the Company's TIRA investments will not be fully recovered through the TIRA adjustment.

Under the proposed CIRA, by contrast, there is no EVM or similar tool the Commission could use to evaluate the efficiency of the Company's work. As Northern put it, the types of projects the CIRA would cover "do not lend themselves to EVM tracking due to the nature of the projects, including uncertain scope, schedule and costs of the projects." Ops. Dir. at 11. Instead, the "CIRA is designed to allow timely recovery of investments . . . including those that lack a defined schedule, scope and cost (which is affected by schedule and scope)." Ops. Dir. at 11. When asked in discovery for "all measures that will be in place to keep CIRA-related costs at or below budget or generally to control CIRA-related costs" absent an EVM or similar tool, the Company pointed to its processes of capital-budget development and capital-spending authorization, which apply to all of the Company's spending, not just the CIRA. EXM-008-008, Att. 1; Tr. at 67–68 (Aug. 28, 2019 Tech. Conf.). Thus, the Company's proposed CIRA would require an annual case to evaluate the prudence of the CIRA investments using traditional ratemaking tools. ODR-001-005 ("[T]he CIRA Tariff does not change the regulatory principles upon which the Commission will evaluate the CIRA-investments and determination of prudence."); EXM-006-022.

In addition, the categories of investment included in the CIRA will not have an end date. The Company proposed that the CIRA would be in place for an "initial term of 3 years," suggesting that, if approved, the Company may propose that the CIRA remain in place after that period. The Commission is uncomfortable with the idea of adopting a capital tracker for categories of investments that will always be necessary for a utility to make, and that have no natural end date. The TIRA, by contrast, applies to investments that will be completed at a known date in the foreseeable future.

These key differences from the TIRA weigh against adopting the CIRA.

3. Efficiencies

The Commission agrees with the Staff and the OPA that the amount of efficiencies to be gained with the CIRA are not well supported. Northern implied that, without the CIRA, it will be forced to file rate cases more frequently, but there is no accounting of that, and no commitment that Northern would file rate cases less frequently with the CIRA. This creates the possibility that, even with the CIRA in place, general rate cases would be filed at the pace they normally would be, over and above the annual CIRA (and existing annual TIRA) rate cases. With the estimated duration of a CIRA case at eight months, it is unclear to the Commission that the CIRA will offer meaningful efficiencies.

4. Use of the Existing 4% Cap

One justification the Company put forth for approving the CIRA was that it would make use of an existing limit: the 4% cap already in place for the TIRA. Presumably Northern was arguing that, because the Commission has already approved a bound on annual rate increases relating to the TIRA, there should be no harm in adopting the CIRA because in no year will the increase exceed the already-approved 4% cap. The Commission rejects this attempt to expand the scope of categories eligible for cost recovery under the established TIRA cap. The 4% cap was specifically crafted and approved for the TIRA and, when formulated, did not take into consideration a body of other costs that might be added to the mix, without an obvious end date in sight.

5. Conclusion

For the above reasons, the Commission does not approve the Company's proposed CIRA. As discussed in Sections VII.C.1 and V.B.1.c.i., the Company's core argument for the CIRA—that it is necessary to help combat attrition and regulatory lag associated with increases in non-growth-producing capital investments—is largely the same as that for year-end rate base. Although the Commission is rejecting the CIRA, we have approved the use of year-end rate base (adjusted for associated sales growth), which should help address the problem of earnings erosion the Company has raised in this case.

As a final note on this subject, the Commission values both the efforts Northern has made to improve the safety of its system over the past several years and Northern's responsiveness to its safety regulators. All indications are that the Company's emphasis on safety and reliability has led to a strong culture of concern and proactiveness about these important issues. The government-mandated and safety-related categories Northern proposed for inclusion in the CIRA are important core tasks of a natural-gas utility. The Commission's rejection of the CIRA should not be read as a negative comment on the Company's efforts to enhance the safety and reliability of its system.

VIII. TARGETED AREA BUILDOUT PROGRAMS IN SACO AND IN SANFORD

A. Background

In two previous dockets, the Commission approved the parameters of programs to govern Northern's targeted area buildout (TAB) programs in Saco and in Sanford.[51] The TAB programs enable Northern to install new infrastructure to serve customers in defined areas while charging those customers—for a 10-year period—a monthly TAB surcharge in lieu of a large upfront contribution in aid of construction (CIAC). Implementation of the TAB program in Saco began in early 2016, while the TAB program in Sanford began in 2018.

In Docket No. 2017-00065, the Commission modified the Saco TAB by approving a TAB incentive mechanism that would shift to the Company (rather than ratepayers) certain risks associated with achieving projected sales under the Saco TAB. Under that mechanism, in the context of setting rates, ratepayers would be at risk for, or would benefit from, sales between 10% below and 10% above levels projected when the TAB was approved. Sales above or below this bandwidth would accrue to the Company. Because new customers participating in the TAB pay for the investments needed to

51 *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Targeted Area Build-Out Program*, Docket No. 2015-00146, Order Approving Stipulation (Dec. 22, 2015) (approving Saco TAB); *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Targeted Area Build-Out Program in Sanford*, Docket No. 2017-00065, Order (June 26, 2017) (approving Sanford TAB); *see also Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 39–40 (Feb. 28, 2018) (establishing incentive mechanism for the Saco TAB).

provide service to them over a 10-year period, rather than through an upfront CIAC, the risks of achieving the sales levels projected by the Company in support of the TAB and the TAB surcharge would shift to Northern's existing customers given that the TAB investment and expenses are included in base rates.

In this case, Northern updated the Staff and parties on the progress of its TAB programs and offered a correction to an illustrative example relating to the TAB that was filed in Northern's last rate case, Docket No. 2017-00065. Ops. Dir. at 35–36; Rev. Req. Dir. at 45–47. Northern also

> request[ed] that the Commission approve an amendment to the Company's TAB Tariff to clarify that a designated TAB area is defined to include adjacent areas into which the Company can further extend its distribution system to meet customer demand, provided that doing so will not result in an increase to the amount or duration of the TAB surcharge.

Rev. Req. Dir. at 49.

The Company provided updates on the progress of the Sanford TAB through the testimony of Messrs. Leblanc, Sprague, and Goulding, Ops. Dir. at 35–36, and on the progress of the Saco TAB through the testimony of Messrs. Goulding and Main, Rev. Req. Dir. at 45–46. In their testimony, the witnesses described the new customer (meter) and revenue targets for the TAB area and showed that results have largely been in line with expectations.

The Company also proposed that the revenue targets set for the Saco TAB incentive mechanism in Docket No. 2017-00065 be revised to reflect the effect on its rates of the Tax Cuts and Jobs Act of 2017 (TCJA).

B. Expansion to So-Called Adjacent Areas

1. Positions of the Parties and Staff

a. Northern

In its direct case, the Company asked to amend its TAB schedules to permit it to expand to "adjacent areas" without notifying or seeking the approval of the Commission so long as that new investment does not affect the TAB surcharge, as calculated in Northern's model. Rev. Req. Dir. at 49. In making this request, the Company pointed out that it has already expanded to two adjacent areas in Saco: the Shannon Woods condominium development, where it has been serving customers (and assessing them the Saco TAB surcharge) since 2017 and the Mill Brook business park, where it has been serving customers (and assessing the surcharge) since 2018. Rev. Req. Dir. at 50; *see also* ODR-001-022, Att. 1 (map of Shannon Woods and Mill Brook expansions). In both cases, Northern explained, the investment met the Company's line-extension criteria, and neither extension would have required a CIAC. Rev. Req. Dir. at 50. Also, according to Northern, its TAB investment model showed that neither investment would have required an increase to the TAB surcharge. ODR-001-025. The Company argued that such expansions are consistent with the language in the stipulation approved for the Saco TAB that allowed Northern the "discretion to modify the size or pace of the Saco TAB project . .. . to adapt to circumstances that may arise during program implementation." *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Targeted Area* Build-Out Program, Docket No. 2015-00146, Order Approving Stipulation (Dec. 12, 2015) (quoted in Rev. Req. Dir. at 51). In discovery, Northern proposed to define an adjacent area as "an area that is in close geographic proximity to the originally defined TAB area and will be served by extending the gas main from gas main infrastructure that was installed under the TAB program." EXM-002-058.

b. The OPA

The OPA disagreed with Northern's position that the stipulation's language applies to expansions of the TAB outside of areas approved in Docket No. 2015-00146. OPA Br. at 44. Instead, the OPA argued, the Order Approving Stipulation in that case refers to the ability to "scale back" the program depending on future circumstances, but makes no mention of expansion. *Id.*

c. Staff

In its Bench Analysis, the Staff supported the Company's expansion efforts but noted an internal inconsistency in the Company's position on whether approval was required for the Saco TAB expansions and its proposed amendment to the TAB tariff. In particular, the Company argued that it should be permitted to expand to adjacent areas when economical and that the stipulation in the Saco TAB docket (Docket No. 2015-00146) shows that the parties contemplated such expansions under the right circumstances. Rev. Req. Dir. at 50–52. At the same time, the Company proposed in this case to amend its tariff to allow for such expansions. On balance, however, given the arguably ambiguous language in the stipulation and the Order Approving Stipulation, Staff did not find that the Company intentionally violated the order by expanding to Shannon Woods and Mill Brook. BA at 64–66.

With respect to the Company's proposed amendment to allow for expansions into "adjacent areas," the Staff argued that the Commission should be informed of such expansions before they occur through a filing by the Company. Staff suggested that the filing include: (1) a map of the TAB areas, including the adjacent area; (2) the TAB model and surcharge calculation reflecting the investments and revenues associated with the expansion; and (3) a demonstration that the existing surcharge is adequate and appropriate. *Id.* at 66–67.

2. Discussion and Decision

As to the expansions of the Saco TAB the Company has undertaken to date, the Commission agrees with the Staff that the language in the stipulation and the Order Approving Stipulation may be ambiguous. It could be argued that the intent was to allow investments only within the agreed-upon, defined boundaries of the TAB area, and that expansion beyond that would require Commission approval. On the other hand, the language in the stipulation creates more room for interpretation. The following pertinent language appears in that stipulation:

> The Parties further agree and request that the Commission grant the Company discretion to modify the size or pace of the Saco TAB project in order to adapt to circumstances that may arise during program implementation. The Parties acknowledge that the TAB was developed based on facts and circumstances reasonably known by the Company, that it is impossible to predict every future fact or circumstance that may affect this program, and therefore the ability to adapt the program to meet changes in facts and circumstances encountered during implementation is a necessary discretion for the Company to exercise. For example, the Saco TAB may be influenced significantly by consumer response, which may lead the Company to modify its program by, among other things, adjusting the construction schedule, or modifying the list of streets it designates for TAB main construction, and modifying other characteristics of the program.

Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Targeted Area Build-Out Program, Docket No. 2015-00146, Order Approving Stipulation, Stip. at 4–5 (Dec. 22, 2015). A reasonable person could read the above language either to require Northern to obtain Commission approval to modify the Saco TAB program, or to permit Northern to do so on its own, without approval. Given this ambiguity, the Commission finds that the Company has not intentionally violated the Commission's order.

With respect to the Company's proposed amendment regarding "adjacent areas," the Commission finds that the amendment is reasonable and would resolve the ambiguity described above. "Adjacent areas" may include only areas that are in close proximity to the original TAB area, along the lines of the definition the Company proposed in response to EXM-002-058. The Company should include language to this effect in its amendment to the TAB tariff.[52]

The Commission also determines that in the future Northern must make a filing before it expands to an adjacent area. The filing would include, at a minimum, the following information: (a) a map of the adjacent TAB area (as part of the whole TAB area) and a description of the area, the proposed investments in the area, and the justification for those investments; (b) the TAB model and surcharge calculation assuming the new investment and revenue that would result from expanding to the adjacent area; and (c) a demonstration that the revenue from the existing surcharge is adequate to cover the cost of the incremental expansion and is appropriate to be charged to the customers in the new, adjacent area. This will allow the Commission and the parties to confirm that the existing surcharge remains reasonable and appropriate. This filing is for informational purposes, but, if an expansion warrants a revision to the surcharge, the Company would be required to submit for the Commission's approval the TAB tariff with proposed changes to the surcharge.

52 Northern submitted schedules with this new proposed language in response to Order (Part I), and those schedules were approved by a delegated Order on Compliance Filing, which issued March 30, 2020.

C. TAB Revenue Targets and Incentive Mechanism

1. Positions of the Parties and Staff

The Staff, in its Bench Analysis, suggested that the revenue targets for the Saco TAB that were set in Docket No. 2017-00065 be revised to reflect the incremental customers and revenue expected from the expansions into Shannon Woods and Mill Brook. BA at 64–65.

In response, the Company argued that the customer and revenue targets assumed in the "settlement model,"[53] which reflect the original TAB area without those expansions, should be maintained. The Company's rationale for this was that the parties to the stipulation approved in Docket No. 2015-00146 anticipated that the assumptions in the "settlement model" could diverge from actual experience due to many factors, and that revised customer and revenue targets could subject it to penalties under the incentive mechanism. Northern Br. at 133–35.

The Company also argued that the revenue targets in the incentive mechanism be revised to reflect the lower base rates resulting from the TCJA. *Id.* at 130–31. The Company argued that, in contrast to the assumption in the "settlement model" that its base rates would increase by 3.0% per year, the TCJA caused a decrease in base rates of 2.30% in 2018.

The Staff, in its Bench Analysis, did not disagree with the Company, but argued that if targets are adjusted for any one exogenous factor, then they should be adjusted for the effect of other things that affect the Company's base rates, such as the annual TIRA adjustments and the changes to base rates in Docket No. 2017-00065. BA at 68–69. In response to the Staff's argument, the Company noted that adjustments to its base rates, including from the TIRA and periodic rate cases, were anticipated and reflected in the revenue targets. In contrast, according to the Company, the TCJA was a significant exogenous event that was neither anticipated nor within its control. Northern Br. at 131.

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53 In Schedule CGDM-3, the Company provided its analysis of whether it had met the sales forecast under the incentive mechanism. Included in Schedule CDGM-3 is the meter-count forecast for each rate class that the Company purports to be "per settlement model." In EXM-011-002, ODR-001-025, and ODR-006-002, the Company was asked to provide the modeling assumptions related to its claims regarding the Saco TAB expansion areas. The per- year customer-meter forecast varies among the responses. Also, the meter assumptions, which are stated to include the expansion areas, are lower than the meter-number assumptions in Schedule CDGM-3, which does not include the expansion area. Staff was asked in ODR-004-003 to provide what it considered the "settlement model," and the meter counts provided there also have discrepancies between the other files. In Exhibit 3 to its exceptions, the Company provided its modeling forecast including the Saco TAB expansion areas.

2. Discussion and Decision

The Company's expansion to areas outside of the originally approved Saco TAB areas introduced a material change to the customer meter and revenue targets originally assumed in the Saco TAB "settlement model." As noted above, under the incentive mechanism, if "the Company did not achieve the target sales or surcharge revenue at 90% of the target levels, the deficiency would be imputed to the Company. On the other hand, if the Company achieved sales or surcharge revenue in excess of 110% of the target, such amounts would flow to the Company." *Northern Utilities, Inc. d/b/a Unitil, Request for Approval of Rate Change Pursuant to Section 307*, Docket No. 2017-00065, Order (Corrected) at 35 (Feb. 28, 2018). The incentive mechanism was meant to address the Commission's concern that, "since new customers are no longer paying the upfront charge to recover the investment associated with providing them service, the risk associated with achieving the sales and penetration rates at the levels projected in the Company's TAB modeling has been shifted to Northern's existing customers given that the Saco TAB investment and expenses are included in base rates." *Id.* at 39. Thus, the Saco TAB incentive mechanism was meant to "help ensure that the targeted customer and sales growth in the TAB area is achieved." *Id.* at 35. In addition, the Commission decided that the "mechanism would be specific to the buildout areas approved by the Commission in Docket No. 2015-00146," *id.* at 35, thus apparently not including so-called adjacent areas.

By including adjacent areas as part of the Saco TAB program, the Company is expanding the boundaries of the TAB area. This, in turn, affects the targets for this TAB area. *See* ODR-001-026, Atts. 1, 2. Thus, the Commission finds that the targets for the incentive mechanism should be revised to reflect the incremental customers and sales expected in the Shannon Woods and Mill Brook areas.

With respect to adjustments to reflect rate levels, as noted above, Northern proposed that the Saco TAB revenue targets be adjusted for the rate decrease that resulted from the TCJA. Staff's position was that, if such an adjustment is permitted, the effects of the annual TIRA adjustments and the outcomes of base-rate proceedings should also be reflected as adjustments to the targets rather than limiting adjustments to select, discrete events.

The issues and arguments in this proceeding about the appropriate rates to use in setting the revenue targets for the TAB incentive mechanism perhaps show the flaw in using pre-established revenue levels to define the targets. Arguments are bound to continue to arise about whether a given rate change was or was not reasonably reflected in the "settlement model." The Commission finds that the targets for the Saco TAB incentive mechanism should be revised to reflect the incremental customers and sales expected in the Shannon Woods and Mill Brook areas. The targets should be structured using customer and sales levels instead of rate levels, and the revenue targets should be calculated using the actual surcharge and base rates in effect during the applicable period. For this case, because the results of that method are not in the record, the Commission will use Exhibit 3 to Northern's March 12, 2020 exceptions (attached to this order as Appendix B) in assessing whether adjustments are necessary under the incentive mechanism. The Commission finds that no adjustments are necessary at this time.

Finally, the Commission agrees with the Staff's recommendation that, for the same reasons the Commission approved such a mechanism for the Saco TAB, an incentive mechanism should be adopted for the Sanford TAB that uses the same structure as the Saco TAB (as modified by this order) but with targets specific to the Sanford TAB, as established by the customer and sales assumptions set out in Docket No. 2017-00037, and using the same method as established for the Saco TAB. Any rate adjustments indicated by the Sanford TAB would be reflected in subsequent base rate proceedings.

IX. CONCLUSION

Accordingly, the Commission

ORDERS

1. That Northern is granted an increase to its annual base-rate revenue requirement of $3,605,412, with new rates to go into effect April 1, 2020;
2. That the rate increase shall be applied across the board evenly to all rate classes and rate components;
3. That this revenue requirement reflects a return on equity of 9.48%, a cost of long-term debt of 5.19%, and a capital structure of 50% common equity and 50% debt;
4. That, for purposes of calculating the TIRA revenue requirement, the pre-tax TIRA rate of return is set at 9.18%, and the Company shall use an ROE of 9.48% for purposes of applying the TIRA Earnings Sharing Mechanism;
5. That these approved rates reflect the inclusion in Northern's rate base of 22% of $12.7 million of USC's CIS implementation investment;
6. That a management audit under 35-A M.R.S. § 113 be initiated for the purpose of examining the Company's implementation of its new customer information system. The audit shall be conducted by an appropriate consultant familiar with CIS implementations, to be selected by the Commission, who will examine the decisions made by management about the hiring and use of vendors and consultants as well as about the scope, schedule, and costs of the implementation. The costs of the audit shall be borne by the Company with a possible allocation of some or all those costs to ratepayers depending on the outcome of the audit and investigation;
7. That, until the audit investigation is completed, Northern may continue to reflect any CIS-related amounts on its books;

8. That Northern develop a written document-retention policy that includes information on how the policy will be communicated to new and existing employees, and submit that policy in this docket for informational purposes as a compliance filing within 90 days of Order (Part I), which issued March 26, 2020;

9. That Northern's request to establish the CIRA is denied;

10. That the Company shall make a filing with the Commission as described in this order prior to expanding any TAB area to an adjacent area;

11. That the Saco TAB incentive mechanism targets shall be revised to reflect the incremental customers in the Shannon Woods and Mill Brook areas, consistent with the assumptions set out in Exhibit 3 to Northern's exceptions;

12. That the Saco TAB incentive mechanism is hereby modified so that the targets are based on projected customer and sales levels and the actual rates in effect during the applicable period;

13. That, consistent with the assumptions in Exhibit 3 to Northern's exceptions, no adjustment under the Saco TAB incentive mechanism is necessary at this time; and

14. That an incentive mechanism for the Sanford TAB is adopted that uses the same method as the Saco TAB (as modified by this order), but with targets specific to the Sanford TAB as established by the customer and sales assumptions set out in Docket No. 2017-00037.

Dated at Hallowell, Maine, this 1st day of April, 2020.

<u>/s/ Harry Lanphear</u>
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR:

Bartlett
Williamson
Davis

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party at the conclusion of an adjudicatory proceeding written notice of the party's rights to seek review of or to appeal the Commission's decision. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. ch. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)–(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.