The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

June 28, 2024

D.P.U. 23-80

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan.

D.P.U. 23-81

Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Gas Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan.

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SUMMARY

The Department of Public Utilities ("Department") issues this Order addressing the petitions filed by Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil" or "Company") on August 17, 2023, seeking increases in electric and gas base distribution rates. The Department docketed the petitions as D.P.U. 23-80 (electric division) and D.P.U. 23-81 (gas division). The Attorney General of the Commonwealth of Massachusetts and the Department of Energy Resources were parties to the proceedings.

Pursuant to G.L. c. 164, § 94, the Department conducted an intensive ten-month investigation of the Company's petitions, which included reviewing and evaluating Unitil's annual revenues and expenses; current and proposed cost-recovery mechanisms; residential and commercial and industrial rate design; and capital structure and return on equity. To facilitate our investigation, the Department required the parties to submit written testimony; gathered evidence through written discovery; held three public hearings to receive public comments; conducted twelve days of evidentiary hearings to cross-examine witnesses and collect additional information; and weighed the parties' arguments submitted through legal briefs. As noted in our decision below, the evidentiary record in these proceedings includes over 4,000 exhibits.

The Department recognizes the economic impact that higher electric and gas base distribution rates have on individual customers, businesses, and the surrounding communities. The Department appreciates hearing from numerous residents, municipal officials, and business owners who shared personal experiences struggling with the high energy costs and their opinions regarding the Company's petitions. These comments and opinions helped the Department gather evidence and inform our decision.

As part of today's decision to allow electric and gas rate increases, the Department reduces the Company's initially requested revenue deficiency by approximately 43 percent for the electric division and by approximately 16 percent for the gas division. This reduction includes lowering the Company's requested return on equity from 10.50 percent for the electric division and 10.75 percent for the gas division to a combined 9.40 percent.

The Department also increases the discount on bills for qualifying electric low-income customers from 34.5 percent to 40 percent. Gas low-income customers will continue to receive a 25-percent discount on their bills. Resources are available for any customer who has difficulty paying their utility bill. Please visit: https://www.mass.gov/info-details/help-paying-your-utility-bill

The Department recognizes the importance of establishing a regulatory paradigm that enables utilities to navigate the Commonwealth's transition to clean energy in a cost-effective manner that provides significant benefits to customers. In today's Order, the Department approves a five-year performance-based ratemaking ("PBR") plan for each of the Company's operating divisions. The plans are intended to incentivize the Company to identify and implement operating efficiencies to minimize future cost increases to customers. As part of the plans, the

Company agrees not to file petitions that seek to increase base distribution rates during the five-year term.

The Department also approves a set of performance scorecard metrics that will measure the range of benefits under a PBR plan in the following categories, which are tied to the goals of the PBR and consistent with the Department's regulatory objectives: (1) improvements to customer service and engagement; (2) reductions in system peak; and (3) strategic planning for climate adaptation.

The Department supports customer conversion to electrified and decarbonized heating technologies, including heat pumps that transfer thermal energy from outside for use in interior structural heating. As such, the Department approves a residential heat-pump rate available to all customers in rate classes RD-1 and RD-2 who install and use heat pumps in all or part of their homes. The Company's proposed heat-pump rate offerings reduce the variable kilowatt-hour rate associated with electric use during the winter when heat pumps would result in increased electricity use to replace traditional gas heating equipment. The Company's heat-pump rate is a reasonable, cost-efficient solution to mitigate the potential high bills associated with heat-pump implementation faced by residential and low-income customers within the context of current rate structure. The Department directs the Company to engage in meaningful outreach and education efforts to raise awareness of the heat-pump rate option.

The Department seeks to dissuade gas customer expansion and to align rate structure with the Commonwealth's climate objectives. To achieve this objective, the Department instructed the Company to revise its per-customer revenue decoupling mechanism to a decoupling approach based on total revenues to discourage the addition of new gas customers.

Under even normal operations, it is essential that utilities maintain a safe and reliable distribution system. As the Commonwealth moves toward electrification, there is heightened scrutiny on the ability of the distribution system to deliver for customers. To that end, the Department has reviewed and modified, as necessary, the Company's vegetation management and storm resiliency programs, which are designed to reduce outages during storms by minimizing the potential for tree and vegetation contact with overhead utility lines and reduce tree exposure along select circuits.

The Department's decision seeks to enable the Commonwealth to move into its clean energy future while simultaneously safeguarding ratepayer interests and maintaining affordability for customers; ensuring safe, reliable, and cost-effective electric and natural gas service; and minimizing the burden on low- and moderate-income households as the transition proceeds.

I. INTRODUCTION

On August 17, 2023, Fitchburg Gas and Electric Light Company, d/b/a Unitil ("Unitil" or "Company") filed separate petitions[1] with the Department of Public Utilities ("Department") to: (1) increase its electric base distribution rates to generate $6,775,526 in additional base distribution revenues;[2] and (2) increase its gas base distribution rates to generate $10,893,803 in additional revenues.[3] Based on changes made during the proceeding, these initial amounts were revised, and the Company's total revenue deficiency for its electric division decreased to $5,142,340, while the total revenue deficiency for the gas division increased to $11,227,825 (Exhs. Unitil-CGDN-10, at 1 (Rev. 4) (electric); Unitil-CGDN-7, at 1 (Rev. 4) (gas)).[4]

In addition to the requested rate increases, Unitil seeks separate five-year performance-based ratemaking ("PBR") plans for its electric and gas divisions, as well as numerous other ratemaking proposals, as discussed in the sections below. Unitil bases its

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1 In the interest of administrative efficiency, the Department investigated both dockets simultaneously and held joint public and evidentiary hearings. Further, we issue only one Order in both dockets. These cases are not consolidated, however, and remain separate proceedings.

2 The Company's initial revenue deficiency included the transfer of $2,673,750 in costs recovered through certain reconciling mechanisms to base distribution rates, effective July 1, 2024. Net of these transfers, the proposed overall increase to distribution revenues was $4,101,776. Unless otherwise noted, the Department has referred to the Company's "AMI Excluded" cost-of-service updates for its electric division.

3 The Company's initial revenue deficiency included the transfer of $4,202,178 in revenue requirement on the capital investments made as part of its Gas System Enhancement Plan to base distribution rates, effective July 1, 2024. Net of these transfers, the proposed overall increase to revenues was $6,691,625.

4 Schedule 1 (electric) and Schedule 1 (gas) below provide the initially requested, adjusted, and final approved revenue requirement for the electric and gas divisions.

proposed base distribution rate increases on a calendar test year of January 1, 2022 through December 31, 2022. The Company was last granted increases in electric base distribution rates and gas base distribution rates through approved settlements in 2020. Fitchburg Gas and Electric Light Company, D.P.U. 19-131 (2020) (gas); Fitchburg Gas and Electric Light Company, D.P.U. 19-130 (2020) (electric). The Department docketed the instant petitions as D.P.U. 23-80 (electric division) and D.P.U. 23-81 (gas division)[5] and suspended the effective date of the proposed rate increase until July 1, 2024, for further investigation.

The Company is a wholly owned utility subsidiary of Unitil Corporation (Exhs. Unitil-RBH-1, at 8 (electric); Unitil-DJH-1, at 8 (gas)). Unitil Corporation is a public utility holding company engaged in the retail distribution of electricity and gas through its three utility subsidiaries: (1) the Company, which provides electric and gas service in Massachusetts; (2) Northern Utilities, Inc. ("Northern Utilities"), which provides gas service in Maine and New Hampshire; and (3) Unitil Energy Systems, Inc. ("UES"), which provides electric service in New Hampshire (Exhs. Unitil-RBH-1, at 8 (electric); Unitil-DJH-1, at 8 (gas)). In addition, Unitil Corporation is the parent company of Granite State Gas Transmission, which is an interstate natural gas pipeline company serving Northern Utilities in Maine and New Hampshire (Exhs. Unitil-RBH-1, at 8 (electric); Unitil-DJH-1, at 8 (gas)).

5 In some instances, the two dockets contain division-specific prefiled direct and rebuttal testimony, supporting schedules, discovery responses, and briefs. For ease of reference, the Department has designated the documents as (electric) or (gas). Where the filing is exactly the same in both dockets, there is no division-specific designation (e.g., Company's Reply Brief).

Unitil Corporation also owns the following subsidiaries: (1) Unitil Service Corp. ("USC"), which provides administrative and professional services to Unitil Corporation's utility subsidiaries; (2) Unitil Realty Corp. ("URC"), which owns and manages its corporate headquarters in Hampton, New Hampshire; (3) Unitil Resources, Inc., which had been the parent of Usource, an energy brokerage and advisory service Unitil Corporation divested in 2019; and (4) Unitil Power Corp., which had functioned as the full requirements wholesale power supply provider for UES, but currently has limited business and operating activities (Exhs. Unitil-RBH-1, at 8-9 & nn.3, 4 (electric); Unitil-DJH-1, at 8-9 & nn.3, 4 (gas)).

The Company provides retail electric and gas distribution service to customers in the City of Fitchburg and the Towns of Ashby, Lunenburg, and Townsend (Tr. 1, at 55). In addition, Unitil provides gas-only distribution service in the City of Gardner and the Town of Westminster (Tr. 1, at 55). In total, Unitil serves approximately 46,600 electric and gas customers in these six communities (Exhs. Unitil-RBH-1, at 8 (electric); Unitil-DJH-1, at 8 (gas); Tr. 1, at 55).

II. PROCEDURAL HISTORY

On August 25, 2023, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention in each docket pursuant to G.L. c. 12, § 11E(a). On September 26, 2023, the Department granted the Department of Energy Resources' ("DOER") petition to intervene as a full party. Pursuant to notice duly issued, the Department held an in-person public hearing in the City of Fitchburg on November 9, 2023, and two virtual public hearings on November 29, 2023. The Department received comments from nearly 30 residents and elected officials opposing the Company's petitions. Numerous commenters raised issues with the Company's energy rates in relation to other Massachusetts distribution utilities and questioned the level of the Company's executive compensation. The commenters also described personal hardships associated with high residential energy bills and noted that commercial and industrial ("C&I") customers were leaving, or choosing not to locate in, the Company's service area.[6] The Department appreciates the thoughtful comments provided by the Company's customers and their representatives.

The Department held eight days of evidentiary hearings from February 1, 2024 through March 1, 2024. In support of its filings, Unitil sponsored the testimony of the following witnesses: (1) Robert B. Hevert, CFA, president and chief administrative officer, Unitil Corporation, and senior vice president, Company; (2) Daniel J. Hurstak, senior vice president, chief financial officer, and treasurer, Unitil Corporation, and vice president and treasurer, Company; (3) Christopher J. LeBlanc, vice president, gas operations, USC; (4) Mark A. Lambert, vice president, customer operations, USC; (5) Carol A. Valianti, vice president, communications and public affairs, USC; (6) Kevin E. Sprague, vice president, engineering, USC; (7) Cindy Carroll, vice president, customer energy solutions, USC; (8) Sara M. Sankowich, director, sustainability and shared services, USC; (9) Christopher J. Goulding, vice president, finance and regulatory, USC; (10) Daniel T. Nawazelski, manager, revenue requirements, USC; (11) Todd R. Diggins, controller and chief accounting officer, Unitil Corporation, and vice president and controller, Company; (12) Andre J. Francoeur, manager, financial planning and analysis, USC; (13) John F. Closson, vice president, shared services and organizational effectiveness, USC; (14) Chad R. Dixon, manager, general accounting, USC; (15) Tressa N.

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6 The Department will address any specific comments, as necessary, in the sections below.

Bickford, manager, utility accounting and budgeting, USC; (16) Laura Terry, manager, total rewards, USC; (17) Jacob Sylvain, supervisor, general accounting, USC; and (18) Emily Anderson, supervisor, regulatory accounting, USC. Unitil also sponsored the testimony of the following external consultant witnesses: (1) Mark Kolesar, managing principal, Kolesar Buchanan & Associates Ltd.; (2) Nicholas A. Crowley, senior economist, Christensen Associates; (3) Ned W. Allis, vice president, Gannett Fleming Valuation and Rate Consultants, LLC; (4) John D. Taylor, managing partner, Atrium Economics, LLC; (5) Ronald J. Amen, managing partner, Atrium Economics, LLC; and (6) Dylan W. D'Ascendis, partner, ScottMadden, Inc.

The Attorney General sponsored the testimony of four witnesses: (1) J. Randall Woolridge, Ph.D., professor of finance at the Pennsylvania State University; (2) David E. Dismukes, Ph.D., consulting economist, Acadian Consulting Group; (3) David J. Garrett, managing member, Resolve Utility Consulting, PLLC; and (4) Lafayette K. Morgan, public utilities consultant, Exeter Associates, Inc. DOER sponsored the joint testimony of three employees from the policy, planning, and analysis division: (1) Marian Harkavy, director, energy policy; (2) Austin Dawson, rates and supply analyst; and (3) Shevie Brown, gas policy analyst.

The Attorney General and DOER each submitted an initial brief in each docket on March 22, 2024. The Company submitted an initial brief in each docket on April 8, 2024. On April 25, 2024, the Attorney General and DOER each submitted a reply brief applicable to both dockets. On May 1, 2024, the Company submitted a single reply brief applicable to both dockets. The evidentiary record in docket D.P.U. 23-80 consists of approximately

2,200 exhibits, while the evidentiary record in docket D.P.U. 23-81 consists of approximately 1,900 exhibits. The evidentiary hearings combined both dockets and included responses to 81 record requests issued at those hearings.

III. PERFORMANCE-BASED RATEMAKING PROPOSALS

A. Introduction

In Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81 (2016), the Company's last adjudicated base distribution rate proceeding, the Department approved a traditional cost-of-service ratemaking structure for both operating divisions and a Capital Cost Adjustment ("CCA") mechanism for the electric division to support capital expenditures between base distribution rate cases. D.P.U. 15-80/D.P.U. 15-81, at 44-55, 364-365. In 2020, the Department approved a settlement that increased base distribution rates by $1.067 million for Unitil's electric division and by $4.596 million (over two years) for Unitil's gas division. D.P.U. 19-131, at 5, 16; D.P.U. 19-130, at 5, 17. The Company continued under a cost-of-service ratemaking structure.[7]

In the instant proceeding, the Company proposes to implement a PBR mechanism for its electric and gas divisions. As discussed in greater detail below, for both its electric and gas divisions, the Company proposes to incorporate revenue cap formulas that include a productivity offset ("X factor"), an explicit consumer dividend, an earnings sharing mechanism and reopener provision, an inflation index based on the Gross Domestic Product Price Index ("GDP-PI") and an exogenous cost recovery provision ("Z factor"). For the electric division's PBR mechanism,

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7 In D.P.U. 19-130, the Company initially proposed a PBR plan but subsequently withdrew the proposal as part of the settlement. D.P.U. 19-130, at 1, 8.

Unitil proposes to use a general total revenue cap, and for the gas division, the Company proposes to use a revenue-per-customer cap. Further, the Company proposes to implement a K-bar mechanism to support electric division capital expenditures between rate cases, consistent with the provision approved for NSTAR Electric Company ("NSTAR Electric") in NSTAR Electric Company, D.P.U. 22-22 (2022).

B. PBR Mechanism Components

1. PBR Plan Term

For both its electric and gas division PBR plans, the Company proposes a five-year term, to begin July 1, 2024, with the first annual rate adjustment thereafter to be effective July 1, 2025 (Exhs. Unitil-RBH-1, at 31 (electric); Unitil-DJH-1, at 26 (gas); proposed M.D.P.U. No. 408, § 1.0 (electric); proposed M.D.P.U. No. 274, § 5.0 (gas)). Under the Company's proposals, annual compliance filings would be submitted on or about March 15th each year for the electric division and on May 15th each year for the gas division (Exhs. Unitil-RBH-1, at 31 (electric); Unitil-DJH-1, at 26 (gas)).

2. X Factor

For both its electric and gas divisions, the Company proposes a productivity offset, or X factor, to be calculated as:

$X = (\%\Delta TFP_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)$, where

$\%\Delta TFP_I$ is the percentage change in the electric/gas distribution industry total factor productivity ("TFP") growth;

$\%\Delta TFP_E$ is the percentage change in economy-wide TFP growth;

$\%\Delta W_E$ is the percentage change in economy-wide input price growth; and

$\%\Delta W_I$ is the percentage change in electric distribution industry input price growth. (Exh. Unitil-NAC-1, at 43, 67-68; proposed M.D.P.U. No. 408, § 2.0 (electric); M.D.P.U. No. 274, § 2.0 (gas)).

For the electric division, Unitil relied on the same TFP study approved for NSTAR Electric in D.P.U. 22-22 (Exh. Unitil-NAC-1, at 35-36). The TFP and input price average in this study spanned fifteen years, from 2006 to 2020 (Exh. Unitil-NAC-1, at 35). The results of the study determined that the empirical X factor for a revenue cap was equal to -1.45 percent (Exh. Unitil-NAC-1, at 35-36). See also D.P.U. 22-22, at 17.[8] For the gas division, Unitil relied on the same TFP study approved for Boston Gas Company ("Boston Gas") in Boston Gas Company, D.P.U. 20-120 (2021) (Exh. Unitil-NAC-1, at 36). The TFP and input price average in this study also spanned fifteen years, but from 2004 to 2018 (Exh. Unitil-NAC-1, at 36). The results of the study determined that the empirical X factor for a revenue cap was equal to -1.30 percent (Exh. Unitil-NAC-1, at 36). See also D.P.U. 20-120, at 34-35.[9] The Company

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8 In D.P.U. 22-22, at 17, the Department found that the TFP study showed that from 2006 through 2020, the average growth in productivity for the regional electric distribution companies was equal to -0.05 percent, while the average productivity growth for the nationwide electric distribution companies was equal to 0.06 percent; the average input price growth for regional electric distribution companies was equal to 3.11 percent, while the average input price growth for the nationwide electric distribution companies was equal to 3.17 percent; and the economy-wide average productivity growth was 0.34 percent, while the economy-wide average input price growth was 2.0 percent. Further, the TFP study calculated the productivity offset using the productivity and input price growth indices for the nationwide electric distribution companies rather than the regional electric distribution companies. D.P.U. 22-22, at 17.

9 In D.P.U. 20-120, at 34-35, the Department found that the TFP study showed that from 2004 through 2018, the average growth in productivity for the regional gas distribution companies was equal to -0.71 percent, while the average productivity growth for the nationwide gas distribution companies was equal to -0.05 percent; the average input price

proposes to set the X factor for both divisions to zero, based on the Department's decision D.P.U. 22-22 (Exh. Unitil-NAC-1, at 43). The Company states that, in doing such, it has constructed implicit consumer dividends for its electric and gas divisions of at least 145 and 130 basis points, respectively, as discussed below (Exhs. Unitil-RBH-1, at 25-26 (electric); Unitil-DJH-1, at 21-22 (gas); Unitil-NAC-1, at 53).

3. Inflation Index and Floor

For both its electric and gas divisions, the Company proposes to base the price inflation index included in the revenue cap formula on the GDP-PI as measured by the U.S. government (Exh. Unitil-NAC-1, at 34-35). Under the Company's proposal, the inflation index would be calculated as the percentage change between the current year's GDP-PI and the prior year's GDP-PI (Exhs. Unitil-NAC-1, at 34-35; proposed M.D.P.U. No. 408, § 6.0 (electric); proposed M.D.P.U. No. 274, § 6.0 (gas)). For each year, the GDP-PI would be calculated as the average of the most recent four quarterly measures of GDP-PI as of the second quarter of the year (proposed M.D.P.U. No. 408, § 6.0 (electric); proposed M.D.P.U. No. 274, § 6.0 (gas)). Additionally, the Company proposes an inflation floor of zero percent and an inflation ceiling (or cap) of five percent (proposed M.D.P.U. No. 408, § 6.0 (electric); proposed M.D.P.U. No. 274, § 6.0 (gas)).

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growth for regional gas distribution companies was equal to 2.37 percent, while the average input price growth for the nationwide gas distribution companies also was equal to 2.37 percent; and the economy-wide average productivity growth was 0.53 percent, while the economy-wide average input price growth was 2.42 percent. Further, the TFP study calculated its proposed productivity offset using the productivity and input price growth indices for the regional gas distribution companies rather than the nationwide gas distribution companies. D.P.U. 20-120, at 35, 82-83.

4. Consumer Dividend

The Company used separate benchmarking studies for each division in support of the consumer dividend proposals, and the studies included both unit cost and econometric analyses (Exhs. Unitil-NAC-1, at 55, 71-109; Unitil-NAC-4; Unitil-NAC-2). For both its electric and gas divisions, the Company proposes to include a consumer dividend of zero basis points (Exhs. Unitil-RBH-1, at 26 (electric); Unitil-DJH-1, at 21-22 (gas); proposed M.D.P.U. No. 408, § 6.0 (electric); proposed M.D.P.U. No. 274, § 6.0 (gas)). The Company states that while the explicit consumer dividend is zero, the proposed zero X factors create an "implicit" consumer dividend of 1.45 and 1.30 for the electric and gas divisions, respectively (Exhs. Unitil-RBH-1, at 25-26 (electric); Unitil-DJH-1, at 21-22 (gas); Unitil-NAC-1, at 53; DPU 13-13 (electric)). Additionally, the Company states that the implicit consumer dividend actually is closer to 1.95 percent for the electric division because the revenue cap has no allowance for customer growth, which the Company assumes will continue to grow at its historical rate of 0.50 percent over the duration of the proposed PBR term (Exh. DPU 13-8 (electric)).

5. K-bar Adjustment

For both its electric and gas divisions, the Company proposes to include 2023 post-test-year capital additions into base distribution rates at the outset of the PBR plan on July 1, 2024 (Exhs. Unitil-KSTB-1, at 27 (electric); Unitil-KSTBCL-1, at 25 (gas)). As part of this proposal the Company would adjust base distribution rates for depreciation expense, return on rate base, associated federal and state income taxes, property taxes, and revenues for all capital additions in service through December 31, 2023.

Further, for the electric division, Unitil proposes, as part of the PBR formula, a K-bar adjustment that would allow additional revenues to be collected through the PBR adjustments, beginning July 1, 2025, to provide funding for capital investments (Exhs. Unitil-NAC-1, at 44; proposed M.D.P.U. No. 408, § 8.0 (electric)).[10] The K-bar approach would establish a level of eligible capital recovery based on a historical average of capital additions placed into service from 2019 through 2023, escalated to current year dollars by the applicable GDP-PI change and an X factor of zero (Exh. Unitil-4 (2/1/24) (electric); proposed M.D.P.U. No. 408, § 8.0 (electric)). Specifically, under the Company's proposal, the K-bar revenue requirement would be calculated by rolling forward 2019 through 2023 plant additions, cost of removal, and retirements and then calculating a revenue requirement based on that theoretical rate base calculation (proposed M.D.P.U. No. 408, § 8.0 (electric)). The K-bar revenue requirement is then compared to the capital investment costs approved in the instant proceeding and adjusted to 2024 costs using the PBR mechanism approved in the instant proceeding to establish the incremental K-bar revenue support (Exh. Unitil-NAC-1, at 46).

Furthermore, the petition for approval of Unitil's Electric Sector Modernization Plan ("ESMP") is currently ongoing in Fitchburg Gas and Electric Light Company, D.P.U. 24-12. In

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10 In 2016, the Alberta Utilities Commission developed a "K-bar" approach to supplemental capital funding for Alberta electric distribution utilities (Exh. Unitil-MK-1, at 37-38 (electric), citing AUC 20414-D01-2016). The Alberta Utilities Commission amended its K-bar method in 2018 (Exh. Unitil-MK-1, at 43 (electric), citing AUC 22394-D01-2018). Under this approach, the I-X PBR formula escalates historical average capital additions not subject to recovery through capital trackers to form the basis of future approved capital recovery (Exh. Unitil-MK-1, at 37-38 (electric)). Recoverable capital expenditures are obtained from the differential between the utility's escalated historical capital needs and what each utility actually will collect under the I-X PBR formula for these types of capital additions (Exh. Unitil-RBH-1, at 26-27 (electric)).

that filing, Unitil is petitioning the Department to recover costs incurred from ESMP investments through a separate reconciling mechanism (Tr. 5, at 511-512). Pursuant to G.L. c. 164, § 92B, the Department must issue an Order in the ESMP docket by August 31, 2024. Thus, due to the uncertainty of the outcome in that proceeding, Unitil provided two illustrative PBR adjustments, one of which includes recovery of ESMP investments through the K-bar mechanism, and another of which does not (Exhs. Unitil-4 (ESMP Excluded) (2/1/24) (electric); Unitil-5 (ESMP Included) (2/1/24) (electric)).

6. Earnings Sharing Mechanism and Reopener Provision

For both its electric and gas divisions, the Company proposes to adopt an earning sharing mechanism ("ESM") consistent with the design approved for NSTAR Electric in D.P.U. 22-22 (Exhs. Unitil-RBH-1, at 28-29 (electric); Unitil-DJH-1, at 23 (gas); Unitil-NAC-1, at 48-50). Specifically, the proposed ESM would trigger a sharing with customers on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) where the computed distribution return on equity ("ROE") exceeds 100 basis points above the ROE authorized in this proceeding (Exhs. Unitil-RBH-1, at 28-29 (electric); Unitil-DJH-1, at 23 (gas); Unitil-NAC-1, at 48-50). The Company's proposed ESM is asymmetric, and customers would not be responsible for earnings deficits at any level (Exhs. Unitil-RBH-1, at 28-29 (electric); Unitil-DJH-1, at 23 (gas); Unitil-NAC-1, at 49). Further, the Company proposes that for any year in which the ROE is above the bandwidth, the percentage of earnings that is to be shared with customers would be credited to customers in the following year and that the impact of the prior year's adjustment would be excluded from the calculation of the subsequent year's sharing (Tr. 5, at 482-483). The Company acknowledges that any ESM adjustment would be subject to a full investigation in an adjudicatory proceeding (proposed M.D.P.U. No. 408, § 10 (electric); proposed M.D.P.U. No. 274, § 10 (gas)).

The Company additionally proposes to include a reopener provision in its proposed electric division and gas division PBR plans (Exhs. Unitil-RBH-1, at 29 (electric); Unitil-DJH-1, at 23 (gas); Unitil-MK-1, at 68-69). Specifically, Unitil proposes to seek to reopen the PBR framework if the Company's earned ROE falls below 6.50 percent in any single calendar year beginning in 2025, or below 7.00 percent for two consecutive calendar years (Exhs. Unitil-RBH-1, at 29 (electric); Unitil-DJH-1, at 23 (gas); Unitil-MK-1, at 68-69). The reopener proceeding would determine the cause of the earnings deficit and whether adjustments should be made to the PBR plan, potentially re-basing the Company's revenue requirement (Exh. Unitil-MK-1, at 68-69).

7. <u>Exogenous Cost Factor</u>

For both its electric and gas divisions, Unitil proposes to include in the PBR adjustment formula an exogenous cost provision, <u>i.e.</u>, Z factor, which it defines as positive or negative changes to its costs that are beyond the Company's control and are not reflected in the GDP-PI or other elements of the PBR adjustment formula (Exh. Unitil-NAC-1, at 47-48). The Company would calculate the exogenous cost factor as a percentage of the previous year's base revenues (proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)).

Unitil proposes that to be eligible for exogenous cost recovery the cost change must: (1) be beyond the Company's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) be unique to the electric (or natural gas) distribution industry as opposed to the general economy; and (4) meet a threshold of "significance" for qualification (Exh. Unitil-NAC-1, at 48; proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)). The Company proposes the significance threshold for exogenous costs to be set for the rate year at $110,000 and $60,000 for the electric and gas divisions, respectively, and for both thresholds to be adjusted annually by the change in GDP-PI (Exh. Unitil-NAC-1, at 48; proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)).

C. Positions of the Parties

1. Attorney General

a. Introduction

As an initial matter, the Attorney General argues that alternative forms of regulation, including PBR plans, do not create ratepayer benefits, particularly during an energy transition like the one in Massachusetts and, as such, the Company's proposed PBR plans should be rejected in favor of a broad-based all-in capital investment tracker (Attorney General Brief at 6-8, 16-18, citing Exhs. AG-DED-1, at 11-12, 16-17; AG-DED-Surrebuttal-1, at 7; Attorney General Reply Brief at 4-6). In particular, the Attorney General rejects the notion that rates under the proposed PBR plans will be stable, predictable, or capped (Attorney General Reply Brief at 8-10). Rather, the Attorney General asserts that rates will increase annually with the PBR adjustment, and the increases will vary (and thus are not capped) depending on certain factors, including inflation (Attorney General Reply Brief at 8-10).

According to the Attorney General, an all-in capital tracker is more transparent and less administratively burdensome compared to the PBR mechanism, and it benefits the Company and ratepayers by balancing timely recovery of prudently incurred capital investments with a proper and thorough review of their necessity and reasonableness (Attorney General Brief at 17). Further, the Attorney General contends that the Company's current electric division capital tracker (i.e., the CCA) has worked well since its inception in 2016 (Attorney General Brief at 17, citing D.P.U. 15-80/D.P.U. 15-81, at 44-55; Attorney General Reply Brief at 11-13). Nevertheless, the Attorney General asserts that if the Department approves a PBR plan for the Company's operating divisions, certain modifications are warranted.

b. X Factor

First, the Attorney General argues that the Company improperly relied on outdated TFP studies from other proceedings and, as such, the proposed negative X factors and implicit consumer dividends are flawed (Attorney General Brief at 10-11; Attorney General Reply Brief at 7-8). Further, the Attorney General contends that with a zero-productivity offset, if the Company's proposed PBR plans are approved, rates will increase annually consistent with the overall rate of inflation over the term of the PBR plan (Attorney General Brief at 10). The Attorney General asserts that the Company's proposed zero X factor is unacceptable (Attorney General Reply Brief at 6-7). Moreover, the Attorney General notes that in Massachusetts Electric Company's and Nantucket Electric Company's (collectively, "National Grid (electric)") pending base distribution rate proceeding the petitioners proposed an X factor of 0.16 percent, and she asserts that an updated TFP study could have just as easily provided a positive X factor for Unitil (Attorney General Brief at 11, citing Exh. NG-MM-NC-1, at 26; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-150).

c. Consumer Dividend

The Attorney General challenges the Company's benchmarking study and the proposed zero percent consumer dividend (Attorney General Brief at 10-12). The Attorney General argues the Department has never approved a consumer dividend of zero and has long recognized ratepayer benefits associated with non-zero consumer dividends (Attorney General Brief at 12, citing D.P.U. 22-22, at 59). Further, the Attorney General notes that even though NSTAR Electric proposed a zero X factor in its last base distribution rate case, the company still proposed to raise the consumer dividend to 0.25 percent (Attorney General Brief at 12, citing D.P.U. 22-22, at 19). Moreover, she asserts that the presence of a so-called implicit consumer dividend is impossible to verify because Unitil relies on outdated TFP analyses and, in any event, is overstated because the capital spending embedded in the calculation of the 1.45 percent productivity factor for the electric division have been increasing at rates higher than those for operation and maintenance ("O&M") expense (Attorney General Brief at 11; Attorney General Reply Brief at 9-10). The Attorney General recommends a consumer dividend for the Company's electric and gas divisions of 0.25 percent (Attorney General Brief at 13, citing Exh. AG-DED-1, at 37).

d. K-bar Adjustment

The Attorney General asserts that if the Department allows the K-bar adjustment, the K-bar revenue requirement should be calculated using a fixed historical average of capital additions placed in service from 2019 through 2023, instead of using a rolling average of capital additions (Attorney General Brief at 13-14, citing Exh. AG-DED-1, at 44). According to the Attorney General, using a rolling average is inappropriate because it could potentially encourage inefficiency and provide an incentive to inflate future K-bar allowances (Attorney General Brief at 13, citing Exh. AG-DED-1, at 44). Further, the Attorney General asserts that any future increases should be adjusted if the Company fails to make minimal capital investments consistent with the K-bar allowance (Attorney General Brief at 13-14, citing Exh. AG-DED-1, at 44-45).

e. Reopener Provision

The Attorney General argues that the Department should reject the proposed reopener provision (Attorney General Brief at 15). According to the Attorney General, the reopener provision would allow Unitil to seek to reset rates, while also insulating the Company from the consequences of poor operating performance (Attorney General Brief at 14 & n.14, citing Tr. 5, at 471). The Attorney General contends that in D.P.U. 22-22, the Department rejected NSTAR Electric's request for a reopener provision and should adhere to that precedent in this case (Attorney General Brief at 15 & n.15, citing D.P.U. 22-22, at 68).

2. DOER

DOER argues that the Company fails to provide any specifics regarding how it would use the purported flexibility in the proposed PBR plans to reduce reliance on natural gas or shift customers to electrified heating or other non-emitting gas alternatives (DOER Reply Brief at 14). DOER does not address any of the specific components in the Company's proposed PBR mechanisms.

3. Company

a. Introduction

The Company asserts that its electric and gas division PBR proposals are necessary to meet the evolving challenges in the current operating environment due to advances in energy technology, various public policies addressing climate change, more stringent customer requirements, additional physical and cybersecurity requirements, and demand for system reliability and resilience (Company Brief at 23 (electric); Company Brief at 24 (gas)). The Company contends that its proposed PBR plans will allow it to accomplish these goals while maintaining its financial integrity (Company Brief at 29 (electric); Company Brief at 38 (gas)). The Company argues that approval of the proposed K-bar mechanism for its electric division is a key component of the PBR plan's ability to accomplish these goals as it will provide adequate and timely revenue support for required capital investments which, in turn, will send positive signals to the financial markets about the Company's outlook (Company Brief at 30 (electric)). Further, the Company maintains that the Department has previously approved plans similar to its current proposal for NSTAR Electric and National Grid (electric) and has done so as a means to meet the challenges of the same operating environment faced by the Company (Company Brief at 57-58 (electric); Company Brief at 25 (gas)).

The Company argues that, taken as a whole, its proposed PBR plans adhere to Department precedent, will provide necessary revenue to support the electric and gas distribution systems, are not excessively focused on cost recovery issues, will achieve specific measurable benefits, and will reduce regulatory and administrative costs (Company Brief at 83 (electric), citing Exhs. Unitil-NAC-1, at 61-67; Unitil-MK-1, at 4-8, 67, 71; Company Brief at 67-68 (gas)).

Thus, the Company asserts that its proposed PBR plans should be approved without modification (Company Brief at 58 (electric); Company Brief at 33 (gas)).

In this regard, the Company disagrees with the Attorney General's position that an all-in capital tracker is a more appropriate alternative than the proposed PBR plans (Company Brief at 83-84 (electric); Company Brief at 69 (gas)). Unitil rejects the notion that the benefits provided by a PBR plan must be greater than any other alternative forms of regulation, and instead the Company submits that it need only demonstrate that the proposed PBR plans are more likely than current regulation to meet Department goals (Company Brief at 84-85 (electric), citing D.P.U. 22-22, at 48; Incentive Regulation, D.P.U. 94-158, at 57 (1995); Company Brief at 69 (gas)). Further, Unitil argues that the Attorney General has provided no evidence to support the claim that the benefits provided by an all-in capital tracker, or those of another alternative form of regulation, would outstrip those of the Company's proposed PBR plans (Company Brief at 84-85 (electric)).

b. X factor

The Company asserts that given the data set used to develop NSTAR Electric's TFP study, as well as the results of more recent TFP studies, it was reasonable for the Company to conclude that the X factor approved in D.P.U. 22-22 was relevant and appropriate for use in the instant proposals (Company Brief at 64-65 (electric), citing Exhs. Unitil-RBH-1, at 4, 25 (electric); Unitil-NAC-1, at 36-38, 42-43; Unitil-MK-1, at 6, 60; Company Brief at 56-57 (gas), citing Exh. Unitil-DJH-1, at 4, 20 (gas)). In this regard, the Company argues that the Attorney General fundamentally misconstrues the role of TFP studies and their relationship to the X factor and has drawn a false comparison between the proposed zero X factors in the instant proceeding and the X factor proposed by National Grid (electric) in D.P.U. 23-150 (Company Brief at 103-104 (electric); Company Brief at 87-88 (gas)).[11] Further, Unitil rejects the notion that the TFP studies are outdated, or the results flawed, as the Company submits that the studies span 15 years of recent data and including "a small number of new observations" would not dramatically change the results (Company Brief at 104 (electric); Company Brief at 88 (gas)).

Finally, Unitil argues that when the empirical X factor is substantially negative, the Company's revenues will grow at a rate that is slower than that of the industry average (Company Brief at 105 (electric); Company Brief at 89 (gas)). Thus, according to the Company, average customer rates will increase more slowly than the industry average, all else equal (Company Brief at 105 (electric); Company Brief at 89 (gas)).

c. Consumer Dividend

Unitil submits that its unit cost benchmarking study demonstrated that the Company's electric and gas divisions face higher costs than most companies, though similar costs compared to other small companies (Company Brief at 70 (electric), citing Exhs. Unitil-NAC-1, at 56; AG 7-52 (electric); RR-AG-30; Company Brief at 61-62 (gas), citing Exh. Unitil-NAC-1, at 57-58). Further, according to Unitil, the econometrics benchmarking studies demonstrated that the Company's costs rose slightly faster than average over the 15-year sample period, but are

11 The Company argues that by referencing the National Grid (electric) TFP study on brief, the Attorney General improperly seeks to introduce extra-record evidence (Company Brief at 103 (electric); Company Brief at 87-88 (gas)). In any event, the Company contends that the Attorney General's argument is invalid because the calculation of the X factor in this proceeding uses the output price measure of GDP-PI rather than the input price measure proposed by National Grid (electric) in D.P.U. 23-150 (Company Brief at 103-104 (electric); Company Brief at 88 (gas)).

not dramatically different from the typical company, both in the national sample and in the Northeast region (Company Brief at 70 (electric), citing Exh. Unitil-NAC-1, at 57; Company Brief at 62 (gas), citing Exh. Unitil-NAC-1, at 58).

The Company asserts that its proposed zero consumer dividend for its electric and gas divisions is appropriate, particularly when viewed in context of the reasonable productivity gains, the PBR mechanism as a whole, and the Company's financial integrity (Company Brief at 71, 110-111 (electric); Company Brief at 63, 96 (gas)). Further, the Company submits that, contrary to the Attorney General's misunderstanding, setting the X factor to zero does, in fact, create an "implicit consumer dividend" of 1.45 for the electric division[12] and 1.30 for the gas division (Company Brief at 47-48, 67, 106 (electric); Company Brief at 40, 58, 90 (gas)). Further, Unitil contends that by proposing a zero X factor, the Company has effectively proposed to reduce the annual revenue adjustment mechanism that would otherwise apply under the Department's PBR method, thereby accepting a significant "stretch factor" that would require meaningful and ongoing operating efficiencies (Company Brief at 65-66, 106 (electric), citing Exh. Unitil-RBH-1, at 4, 25 (electric); Company Brief at 57, 90 (gas), citing Exh. Unitil-DJH-1, at 4, 20 (gas)). According to Unitil, a zero X factor will require the Company to achieve significantly greater efficiency gains than would result if the factor was set closer to the empirical industry average TFP (Company Brief at 66, 106 (electric), citing Exh. Unitil-MK-1, at 6, 60; Company Brief at 57, 90 (gas)). Thus, the Company asserts that because this larger

[12] The Company further argues that the revenue cap formula for its electric division does not allow increases in revenue due to an increase in its customer base, which creates an implicit consumer dividend that is closer to 1.95 if current customer growth continues at its historical pace (Company Brief at 106-107 (electric)).

productivity offset is set out in the I-X mechanism in the PBR plans, consumers will be guaranteed a more immediate and larger share of benefits in the annual rate adjustments, which represent benefits beyond the Department's historically approved consumer dividend amounts (Company Brief at 66, 106 (electric), citing Exh. Unitil-MK-1, at 6, 60; Company Brief at 57, 90 (gas)). The Company also insists that its small size and lack of ability to benefit from economies of scale will make it more difficult to benefit from efficiency improvements, and that due to its size it should not be expected to have a consumer dividend equal to that of its larger peers (Company Brief at 107-108 (electric); Company Brief at 90-91 (gas)).

Finally, the Company rejects the Attorney General's recommendation that the Department should apply a consumer dividend of 0.25 percent, similar to what was approved for NSTAR Electric in D.P.U. 22-22 (Company Brief at 112 (electric); Company Brief at 95-96 (gas)). The Company argues that the consumer dividend in D.P.U. 22-22 essentially was a "negotiated" number that was found to be appropriate when considering the other changes and modifications made to the PBR plan in that proceeding (Company Brief at 112 (electric), citing D.P.U. 22-22, at 59; Company Brief at 95-96 (gas)).

d. K-bar Adjustment

Unitil argues that in approving the K-bar in D.P.U. 22-22, the Department found that NSTAR Electric required flexibility to address evolving energy and climate policies and to maintain aging infrastructure and enhance resiliency to address climate change (Company Brief at 73-74 (electric), citing D.P.U. 22-22, at 60-61). Further, the Company notes that in D.P.U. 22-22, the Department also found that any capital investment program must encourage prudent investments while maintaining efficiencies and appropriate cost control measures

(Company Brief at 74 (electric), citing D.P.U. 22-22, at 60-61). In addition, the Company points to the Department's finding that while capital spending will be critical to achieve the Commonwealth's growing electrification needs and ambitious climate targets, a multi-year PBR plan should have reasonable and predictable rate impacts for distribution customers, especially given the volatility of deregulated energy supply (Company Brief at 74 (electric), citing D.P.U. 22-22, at 60-61). Unitil asserts that it is in the same position as NSTAR Electric and that the foregoing considerations are equally applicable in the instant proceeding as they were in D.P.U. 22-22 (Company Brief at 74-75 (electric), citing Exhs. Unitil-RBH-1, at 26-27; Unitil-NAC-1, at 45; Unitil-MK-Rebuttal at 18-19); Unitil-KSTB-1, at 30-33 (electric); Unitil-KSTB-13 (electric); AG 1-18 (Rev.); DPU 41-2 (electric)).

In particular, the Company argues that consistent with D.P.U. 22-22, the Department should approve a rolling average of historical capital additions for use in calculating the K-bar revenue requirements and should reject the Attorney General's recommendation to use a fixed five-year historical average (Company Brief at 116-119 (electric), citing D.P.U. 22-22, at 66). The Company argues that using a fixed five-year average of capital additions, as recommended by the Attorney General, would not appropriately capture the capital spending that the Company will undergo over the PBR term to further the Commonwealth's energy transition (Company Brief at 118 (electric)). Further, Unitil asserts that using a fixed five-year average of capital additions would provide the Company with a predictable revenue stream regardless of whether it places capital additions into service at an appropriate pace, which could be worse for customers if the Company is under-investing (Company Brief at 118-119 (electric)).

Regarding investing, Unitil rejects the Attorney General's recommendation to adjust allowed K-bar increases if the Company fails to make investments at an appropriate pace (Company Brief at 119 (gas)). According to Unitil, the Department already has the ability to investigate capital spending if it concludes the Company inappropriately over-estimated its budget forecasted in this proceeding ("Forecasted Budget") or is lagging on investment implementation (Company Brief at 119 (electric)). Additionally, the Company notes that in D.P.U. 22-22, the Department implemented a ten-percent cap to allow a degree of flexibility from the Forecasted Budget while still providing protections for customers (Company Brief at 119 (electric), citing D.P.U. 22-22, at 63).

The Company also raises the issue of ESMP recovery and the K-bar (Company Brief at 75-78 (electric)). The Company argues that the optimal route for ESMP recovery, outside of recovery through a separate reconciling mechanism, would be for the Department to approve the K-bar for core capital additions and then also allow the Company to recover the revenue requirement for completed ESMP capital additions as an overlay to the allowed K-bar core capital recovery (Company Brief at 78 (electric)). The Company maintains that if ESMP recovery is not authorized as an aspect of the PBR plan, then the Company will need to deprioritize ESMP investments until later years (Company Brief at 78 (electric)).

e. ESM and Reopener Provisions

Unitil argues that the proposed ESM will provide an opportunity for the Company's customers to more immediately share in the benefits of the PBR plans, rather than receiving the benefits only at the end of the PBR terms when the revenue requirement is rebased (Company Brief at 79-80 (electric), citing Exhs. Unitil-MK-1, at 63-64; Unitil-MK-Rebuttal at 7; Company

Brief at 45-46). Unitil contends that it did not propose a symmetrical ESM where customers would share earnings and deficits to prevent customers from facing price risk if the Company earns less than its authorized return, unless and until the earnings gap is substantial enough to warrant a new base distribution rate case (Company Brief at 80 (electric); Company Brief at 46 (gas)). The Company notes that instead of proposing a symmetrical ESM, it proposed the reopener provision (Company Brief at 80 (electric), citing Exh. Unitil-RBH-1, at 29 (electric); Company Brief at 46 (gas), citing Exh. Unitil-DJH-1, at 23 (gas)).

Unitil asserts that, contrary to the Attorney General's contention, the reopener provision does not insulate the Company from subpar performance, and the Department would be under no obligation to alter the PBR plan to compensate the Company for poor management or inefficiency (Company Brief at 80-81 (electric); Company Brief at 65 (gas)). According to the Company, the Department would have latitude to enact remedial solutions that would leave shareholders, not ratepayers, responsible for corrective measures (Company Brief at 81 (electric); Company Brief at 65-66 (gas)). The Company further contends that the reopener provision is reasonable because Unitil is a small company that will be operating under PBR plans for the first time and, therefore, it requires this additional safeguard to protect its financial integrity (Company Brief at 82 (electric); Company Brief at 66 (gas)).

The Company further rejects the Attorney General's argument that the reopener provision is similar to the ROE risk adjustment that the Department rejected for NSTAR Electric in D.P.U. 22-22 (Company Brief at (electric); Company Brief at 97 (gas)). In particular, the Company asserts that the proposed ROE risk adjustment would have entitled NSTAR Electric to an automatic adjustment without Department review, while the reopener provision proposed by

Unitil carries no such automatic alteration (Company Brief at 123 (electric); Company Brief at 98 (gas)).

f. Exogenous Cost Factor

The Company argues that its proposed Z factor for its electric and gas divisions align with Department precedent as it is consistent with the Z factors recently approved by the Department in other proceedings (Company Brief at 82 (electric), citing D.P.U. 22-22; D.P.U. 20-120; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150 (2019); NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (2017); Company Brief at 67-68 (gas)).

D. Analysis and Findings

1. Introduction

In the sections below, we review our ratemaking authority and conclude that, pursuant to G.L. c. 164, § 94, the Department may implement PBR as an adjustment to cost of service/rate of return regulation. Further, we discuss the factors that the Department has applied to review incentive regulation proposals. Finally, we review the Company's proposed PBR plans, and we determine whether allowing its PBR plans is in the public interest and will result in just and reasonable rates.

2. Department Ratemaking Authority

Pursuant to G.L. c. 164, § 94, the Legislature has granted the Department extensive ratemaking authority over electric distribution companies ("EDCs") and local gas distribution companies ("LDCs").[13] The Supreme Judicial Court has consistently found that the Department's authority to design and set rates is broad and substantial. See, e.g., Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 477, 485 (1956). Because G.L. c. 164, § 94 authorizes the Department to regulate the rates, prices, and charges that EDCs and LDCs may collect, this authority includes the power to implement revenue adjustment mechanisms such as a PBR. Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 234-235 (2002); see also G.L. c. 164, § 1E (authorizes Department to establish PBR for jurisdictional electric and gas companies).

The Department is not compelled to use any particular method to establish rates, provided that the end result is not confiscatory (i.e., deprives a distribution company of the opportunity to realize a fair and reasonable return on its investment). Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 19 (1978). The Supreme Judicial Court has held that a basic principle of ratemaking is that "the department is free to select or reject a particular method as long as its choice does not have a confiscatory effect or is not otherwise illegal." American Hoechest Corporation v. Department of Public Utilities, 379 Mass. 408, 413 (1980), citing Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 302 (1978).

In addition, G.L. c. 164, § 76, grants the Department broad supervision over EDCs and LDCs. Under G.L. c. 164, § 76C, the Department has the authority to establish reasonable rules and regulations consistent with G.L. c. 164, as needed, to carry out its administration of jurisdictional companies in the public interest. Investigation into Rate Structures that Promote

[13] Pursuant to G.L. c. 165, § 2, the Department's ratemaking authority under G.L. c. 164, § 94, also applies to water distribution companies.

Efficient Deployment of Demand Resources, D.P.U. 07-50-B at 26-27 (2008). See also Cambridge Electric Light Company v. Department of Public Utilities, 363 Mass. 474, 494-496 (1973).

Although the Department traditionally has relied on cost of service/rate of return regulation to establish just and reasonable rates, there have been many variations and adjustments in the specific application of this model to individual utilities as circumstances have differed across companies and across time. D.P.U. 07-50, at 8. Over the years, EDCs and LDCs subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See, e.g., D.P.U. 22-22, at 80-81; D.P.U. 20-120, at 102-103; NSTAR Gas Company, D.P.U. 19-120, at 58 (2020); D.P.U. 18-150, at 47; D.P.U. 17-05, at 371-372; Bay State Gas Company, D.T.E. 05-27, at 382 (2005); Boston Gas Company, D.T.E. 03-40, at 471 (2003); The Berkshire Gas Company, D.T.E. 01-56, at 10 (2002); Massachusetts Electric Company and Eastern Edison Company, D.T.E. 99-47, at 4-14 (2000).

Consistent with the discussion above, the Department reaffirms that we may implement PBR as a modification to cost of service/rate of return regulation under the broad ratemaking authority granted to us by the Legislature under G.L. c. 164, § 94. In addition, the Department validates the propriety of the continued use of PBR as a meaningful regulatory format.

3. Evaluation Criteria for PBR

The Department must approach the setting of rates and charges in a manner that: (1) meets our statutory obligations under G.L. c. 164, § 94, to ensure rates that are just and reasonable, not unjustly discriminatory, or unduly preferential; and (2) is consistent with long-standing ratemaking principles, including fairness, equity, and continuity. D.P.U. 07-50, at 10-11. Further, the Department must establish rates in a manner that balances a number of these key principles to reflect and address the practical circumstances attendant to any individual company's base distribution rate case. D.P.U. 07-50-A at 28. The Department has implemented PBR plans or PBR-like mechanisms on a finding that such regulatory methods would better satisfy our public policy goals and statutory obligations. See, e.g., Boston Gas Company, D.P.U. 96-50 (Phase I) at 261 (1996); D.P.U. 94-158, at 42-43; New England Telephone and Telegraph Company, D.P.U. 94-50, at 139 (1995).

As part of our investigation of incentive ratemaking, the Department examined the criteria to evaluate PBR proposals for EDCs and LDCs. D.P.U. 94-158, at 52-66. The Department found that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review established by G.L. c. 164, § 94, which requires that rates be just and reasonable. D.P.U. 94-158, at 52; Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256 n.13 (2002) (in determining propriety of rates under G.L. c. 164, § 94, Department must find that rates are just and reasonable). Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. D.P.U. 94-158, at 57. Finally, a well-designed incentive mechanism should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers that are greater than would be present under current regulation. D.P.U. 94-158, at 57.

In addition to these criteria, the Department established additional factors that it would weigh in evaluating incentive proposals. D.P.U. 94-158, at 57. These factors provide that a well-designed incentive proposal should: (1) comply with Department regulations, unless accompanied by a request for a specific waiver; (2) be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services; (3) not result in reductions in safety, service reliability, or existing standards of customer service; (4) not focus excessively on cost recovery issues; (5) focus on comprehensive results; (6) be designed to achieve specific, measurable results; and (7) provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. D.P.U. 94-158, at 58-64.

4. Rationale for PBR

The production and consumption of electricity in Massachusetts is evolving. Legislative and regulatory initiatives underpin these changes, through policy initiatives designed to address climate change and to foster a clean energy economy through the promotion of energy efficiency, demand response, and distributed generation, and the procurement of long-term contracts for renewable energy. See, e.g., An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, § 68 ("2022 Clean Energy Act"); An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8, § 87 ("2021 Climate Act"); Massachusetts 2050 Decarbonization Roadmap;[14] An Act Relative To Green Communities, St. 2008, c. 169 ("Green

[14] The Massachusetts 2050 Decarbonization Roadmap defines eight decarbonization pathways, and the "All Options" pathway is the benchmark compliant decarbonization

Communities Act"); An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298; An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, § 36; Green Communities Expansion Act, § 83A; Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016). Both EDCs and LDCs must adapt to these policy-driven market developments.

As described above, the Company proposes to operate under a PBR plan for both its electric and gas divisions for the next five years (Exhs. Unitil-RBH-1, at 31 (electric); Unitil-DJH-1, at 26 (gas); proposed M.D.P.U. No. 408, § 2.0 (electric); proposed M.D.P.U. No. 274, § 2.0 (gas)). Unitil states that its operating environment is changing due to evolutions in energy technology, policies addressing climate change, more stringent customer requirements, and a need for system resilience and security, and that the Company's proposals in the instant proceeding are designed to adapt to this evolving environment (Exhs. Unitil-RBH-1, at 13-15 (electric); Unitil-DJH-1, at 14-16 (gas)). According to the Company, PBR affords the Company the latitude to focus on operations and to meet expectations, while providing the critical resources necessary to respond to and meet the public policy objectives outlined above (Exh. Unitil-MK-1, at 70-71). In addition, the Company submits that the PBR plan will support both capital investment and O&M costs (Exh. Unitil-MK-1, at 60-61). Further, the Company expects that without a PBR plan, the Company would likely file at least one additional base distribution rate case through the end of 2029 to keep up with the substantial capital investment

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pathway using midpoint assumptions across most technical parameters (Massachusetts 2050 Decarbonization Roadmap at 15, found at: https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download).

expected over a five-year period (Exhs. Unitil-RBH-Rebuttal at 13 (electric); Unitil-DJH-Rebuttal at 9 (gas)).

As discussed above, the Attorney General argues that the Company's PBR plans do not create ratepayer benefits and should be rejected in favor of an all-in capital tracker (Attorney General Brief at 6-8, 16-18, citing Exhs. AG-DED-1, at 11-12, 16-17; AG-DED-Suirrebuttal-1, at 7; D.P.U. 15-80/D.P.U. 15-81, at 44-55; Attorney General Reply Brief at 4-6, 8-13). Further, as detailed above, the Attorney General recommends several modifications to the Company's proposals, should the Department approve a PBR plan.

The Department finds that the Company has demonstrated that its PBR plans for its electric and gas divisions, as modified below, are appropriate modifications to traditional cost of service/rate of return ratemaking. In particular, the proposed PBR plans are designed to support the Company's ability to adapt to a changing regulatory environment and navigate the demands of the Commonwealth's energy transition in an efficient, cost-effective manner throughout the five-year term (Exhs. Unitil-RBH-1, at 13-15, 19-20 (electric); Unitil-RBH-Rebuttal at 13 (gas); AG 7-28 & Att. (electric); Unitil-DJH-1, at 13-16 (gas); Unitil-DJH-Rebuttal at 10 (gas); AG 7-34 & Att. (gas)). The Department expects that under the PBR plans, Unitil will have a reliable source of revenue to meet the capital and O&M demands necessary to move the Company toward electrification and decarbonization, while also achieving cost efficiencies and ensuring that customers are not subjected to frequent base distribution rate proceedings (Exhs. Unitil-RBH-Rebuttal at 13 (electric); Unitil-DJH-Rebuttal at 10 (gas)). As discussed below, the Department approves for Unitil's electric division a K-bar approach to capital spending within the approved PBR plan. The flexibility and revenue predictability provided by the K-bar approach should allow the Company to address considerable capital spending to meet the clean energy transition goals, as well as other future expenses, without additional cost recovery filings (Exhs. Unitil-RBH-1, at 26-27 (electric); Unitil-KSTB-1, at 30-33 (electric); Unitil-NAC-1, at 45; Unitil-MK-Rebuttal at 18-19; Unitil-KSTB-13 (electric); AG 1-18 (Rev.); DPU 41-2 (electric)). Further, the K-bar approach is formulaic in nature, which provides for simplicity and a measure of administrative ease during the annual PBR filing review (Exh. Unitil-NAC-1, at 47; proposed M.D.P.U. No. 408, § 8.0 (electric)).

In addition, the Department finds that, in this instance, the PBR plans are better suited to satisfy the Department's public policy goals and statutory obligations than the Attorney General's proposed all-in capital tracker. In particular, the Department finds an all-in tracker that provides dollar-for-dollar recovery for investments is inconsistent with the principle of spending efficiency that a PBR plan is intended to encourage. Further, in contrast to the K-bar approach for capital cost recovery, the Attorney General's recommended all-in capital tracker would require annual review of all capital investments, which may be unduly burdensome and difficult to complete in a timely manner.

As discussed in Section IV.D. below, the Department has approved a variety of PBR-specific metrics to measure the Company's performance and the full range of benefits that will accrue under the PBR plan with the goal of assuring customers and stakeholders that standards of service are maintained or improved, and that meeting clean energy goals are advanced during the PBR term. As such, we are satisfied that the Company's proposed PBR plans are not overly focused on cost recovery. Below, the Department addresses the specific components of the PBR plans and whether the proposed PBR mechanisms appropriately balance ratepayer and shareholder risk, are in the public interest, and will result in just and reasonable rates.

5. PBR Plan Components

a. PBR Plan Term

The Company proposes a five-year PBR term for both its electric and gas division (Exhs. Unitil-RBH-1, at 31 (electric); Unitil-DJH-1, at 26 (gas); proposed M.D.P.U. No. 408, § 2.0 (electric); proposed M.D.P.U. No. 274, § 2.0 (gas)). The five-year PBR term would commence on July 1, 2024, and expire on June 30, 2029, during which there would be four annual PBR mechanism adjustments, taking effect each July 1, beginning in 2025 (Exhs. Unitil-RBH-1, at 6 (electric); proposed M.D.P.U. No. 408, § 2.0 (electric); Unitil-DJH-1, at 6 (gas); proposed M.D.P.U. No. 274, § 2.0 (gas)). In conjunction with the PBR term, the Company proposed for both its electric and gas division a stay-out provision whereby the Company may not file a base distribution rate case during the PBR term if it would result in new base distribution rates going into effect earlier than July 1, 2029, subject to the proposed reopener provision (proposed M.D.P.U. No. 408, § 2.0 (electric); M.D.P.U. No. 274, § 2.0 (gas)).

The Department has found that a well-designed PBR plan should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions. D.P.U. 96-5 (Phase I) at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272. In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 19-120, at 63; D.P.U. 18-150, at 53; D.P.U. 17-05, at 402; D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 64.

Previous PBR plans approved by the Department have had terms of five and ten years. See, e.g., D.P.U. 22-22, at 54 (five years, with a possible five-year extension); D.P.U. 20-120, at 72 (five years); D.P.U. 19-120, at 65 (ten years); D.P.U. 18-150, at 56 (five years); D.P.U. 17-05, at 404 (five years); D.T.E 05-27, at 399 (ten years); D.T.E. 03-40, at 495-496 (ten years); D.T.E. 01-56, at 10 (ten years); D.P.U. 96-50 (Phase I) at 320 (five years).

As noted above, the Company intends to undertake substantial capital investments over the next five-year period to meet the Commonwealth's clean energy transition goals of increased electrification and decarbonization, as well as to maintain safe and reliable service (Exhs. Unitil-RBH-1, at 27 (electric); Unitil-KSTB-1, at 30-33 (electric); Unitil-KTSB-13 (electric); Unitil-KSTBCL-1, at 26-29 (gas); Unitil-KSTBCL-13 (gas); Unitil-MK-1, at 61). Based on the specific circumstances presented in this case, the Department concludes that a five-year PBR term will allow for the resources and flexibility necessary for the Company to adjust its operations and investments efficiently and, in turn, best ensures ratepayer benefits of increased operational efficiencies and improved service, and the opportunity for avoided administrative costs. The Department therefore approves a PBR plan term of five years for both Unitil's electric and gas divisions. In addition, a stay-out provision provides the important benefit to ratepayers of ensuring strong incentives for cost containment under the PBR. D.P.U. 22-22, at 55; D.P.U. 19-120, at 65; D.P.U. 18-150, at 55; D.P.U. 17-05, at 403. Accordingly, the Department adopts a stay-out provision in conjunction with the five-year term. We address the reopener provision in Section III.D.5.g. below.

b. Revenue Cap

For the electric division's PBR mechanism, Unitil proposes to use a general total revenue cap based on the I-X formula and also accounting for the Z factor, the K-bar, and the ESM (Exh. Unitil-NAC-1, at 33).[15] For the gas division, the Company proposes a similar cap, but with two differences: (1) there is no K-bar provision; and (2) the proposed revenue cap contains a decoupling mechanism that allows for revenue growth associated with new customers, making it a revenue-per-customer cap (Exh. Unitil-NAC-1, at 34).[16]

The Department approves the revenue cap formula, as proposed for the electric division PBR mechanism. In Section XIII.I.2. below, the Department determined that for its gas division, the Company must transition to a revenue decoupling mechanism ("RDM") based on total revenues, rather than a revenue-per-customer approach. Accordingly, the Department directs the

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15 The formula is as follows:

$$Revenue_t = (Revenue_{t-1} * (1 + I_t – X - CD)) + Z_t + K_t + ESM_t$$

Where $Revenue_t$ represents a given year's allowed revenues; $Revenue_{t-1}$ represents the prior year's allowed revenues; I_t is the measure of inflation in the given year; X is the productivity factor; K_t is the K-bar mechanism in the given year; CD is the consumer dividend; Z_t is the exogenous cost mechanism; and ESM_t is the earnings sharing mechanism.

16 The formula is as follows:

$$Revenue_t / Customer_t = (Revenue_{t-1} / Customer_t * (1 + I_t – X - CD)) + Z_t + ESM_t$$

Where $Revenue_t$ represents a given year's allowed revenues; $Revenue_{t-1}$ represents the prior year's allowed revenues; $Customer_t$ represents the number of customers in the given year; $Customer_{t-1}$ represents the number of customers in the prior year; I_t is the measure of inflation in the given year; X is the productivity factor; CD is the consumer dividend; Z_t is the exogenous cost mechanism; and ESM_t is the earnings sharing mechanism.

Company to modify the gas division's revenue cap formula consistent with the findings in this Order to the following form:

$$Revenue_t = (Revenue_{t-1} * (1 + I_t - X - CD)) + Z_t + ESM_t$$

Where $Revenue_t$ represents a given year's allowed revenues; $Revenue_{t-1}$ represents the prior year's allowed revenues; I_t is the measure of inflation in the given year; X is the productivity factor; CD is the consumer dividend; Z_t is the exogenous cost mechanism; and ESM_t is the earnings sharing mechanism.

c. Productivity Offset

As noted above, the Company proposed for its electric and gas divisions an X factor of zero percent (Exh. Unitil-NAC-1, at 43, 67-68; proposed M.D.P.U. No. 408, § 2.0 (electric); M.D.P.U. No. 274, § 2.0 (gas)). The Department acknowledges the Attorney General's concerns with respect to the Company's reliance on the TFP studies submitted in D.P.U. 22-22 and D.P.U. 20-120 (Exh. AG-DED-1, at 29-33; Attorney General Brief at 10-11; Attorney General Reply Brief at 7-8). We recognize that TFP analyses frequently change from year to year, which suggests that using the most recent range of data is more appropriate and would allow us to verify the Company's claim that the X factor calculates to -1.45 for the electric division and -1.30 for the gas division (Exh. Unitil-NAC-1, at 35-36). In this instance, however, the Department finds that the Company's reliance on the TFP studies submitted in D.P.U. 22-22 and D.P.U. 20-120 do not warrant a rejection of the Company's PBR proposals. Despite Unitil's claims regarding the validity of the TFP studies, the Company voluntarily set the X factors to zero, consistent with NSTAR Electric's proposal in D.P.U. 22-22, to be implemented in conjunction with the K-bar adjustment (Exh. Unitil-NAC-1, at 43).

The Department finds that the Company's proposed X factors of zero are appropriate, particularly when considering the other changes and modifications to the PBR plans approved herein. D.P.U. 22-22, at 57. As such, we approve X factors of zero. Should the Company propose to continue a PBR plan in each of its next base distribution rate cases, the Department directs the Company to use TFP studies that employ the most recent 15 years of data available, as continued reliance on the TFP studies submitted in D.P.U. 22-22 and D.P.U. 20-120 (or TFP studies submitted in other utilities' rate proceedings) would be inappropriate.

d. Inflation Index

In D.P.U. 94-50, at 141, the Department found that the GDP-PI is the most accurate and relevant measure of output price changes for the bundle of goods and services the TFP growth for which is measured by the Bureau of Labor Statistics. In addition, the Department found that GDP-PI is: (1) readily available; (2) more stable than other inflation measures; and (3) maintained on a timely basis. D.P.U. 94-50, at 141. In the instant proceeding, no party disputes that the GDP-PI is an appropriate measure for inflation in a revenue cap PBR formula. The Department finds that the Company's use of GDP-PI as an inflation index in the PBR formula is reasonable and, therefore, we approve its use.

As described above, the Company has proposed to include an inflation cap of five percent in the revenue cap formula for both its electric and gas divisions, meaning that even if inflation rises above five percent, the Company will set the inflation component of the PBR formula at five percent (proposed M.D.P.U. No. 408, § 6.0 (electric); proposed M.D.P.U. No. 274, § 6.0 (gas)). The parties did not raise any objections to the proposed inflation cap. Accordingly, the

Department approves the Company's proposed inflation index using GDP-PI and an inflation cap of five percent.

The Company also proposed an inflation floor of zero so that a negative PBR adjustment would not occur (proposed M.D.P.U. No. 408, § 6.0 (electric); proposed M.D.P.U. No. 274, § 6.0 (gas)). The Department finds that an inflation floor of zero, to correspond with the approved X factor, is a reasonable component of the PBR mechanisms for the Company's electric and gas divisions, particularly when coupled with the inflation index cap approved above. Accordingly, the Department approves an inflation floor of zero for the Company's electric and gas divisions.

e. Consumer Dividend

The consumer dividend is intended to reflect expected future productivity because of the move from cost-of-service ratemaking to incentive regulation. D.P.U. 96-50 (Phase I) at 165-166, 280. As a deduction to the PBR adjustment, the consumer dividend is designed to share these productivity gains with ratepayers (Exhs. Unitil-NAC-1, at 71, Unitil-RBH-1, at 25 (electric); Unitil-DJH-1, at 21 (gas)). The Department has found that a consumer dividend represents an explicit, tangible ratepayer benefit. D.P.U. 22-22, at 59; D.P.U. 20-120, at 83; D.P.U. 19-120, at 86; D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395.

As discussed above, the Company proposed to include a consumer dividend of zero basis points but argues that the X factor set to zero combined with the stretch created by the growth in customer base creates an "implicit" consumer dividend of up to 195 basis points for the electric division and 130 basis points for the gas division (Exhs. Unitil-RBH-1, at 25-26 (electric); Unitil-DJH-1, at 21-22 (gas); Unitil-NAC-1, at 53; DPU 13-8 (electric); DPU 13-13 (electric)).

The Department is not persuaded by the Company's position. First, we are unable to discern from the TFP studies, which as noted do not provide updated data, the accuracy of the Company's calculations. Second, the Department has never approved an explicit consumer dividend of zero, having routinely found a consumer dividend to be an explicit, tangible ratepayer benefit. See, e.g., D.P.U. 22-22, at 59; D.P.U. 20-120, at 83; D.P.U. 19-120, at 86; D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395.[17] Third, the Company acknowledges that a utility implementing a PBR plan for the first time will have a greater potential for incremental performance gains than a utility already operating on such a plan (Exhs. DPU 13-13 (electric); DPU 11-10 (gas)). Fourth, the unit cost and econometrics benchmarking studies demonstrate that the Company's cost performance is below average, and the Department has found that average and below average cost performers, and even utilities where future productivity gains may be lower than expected, should adopt consumer dividends above zero (Exhs. Unitil-NAC-1, at 56-59; AG-DED-1, at 36-40; AG-DED-3, Schs. 3-6; AG 7-52 (electric); AG 7-53 (electric); AG 7-54 (electric); AG 7-55 (gas); AG 7-56 (gas); AG 7-57 (gas)). D.P.U. 20-120, at 92-93; D.P.U. 18-150, at 61-62; D.P.U. 17-05, at 394-395; D.P.U. 03-40, at 485. Fifth, the Company acknowledges that a consumer dividend reflects future expected productivity or cost efficiency gains, and the Department expects that the PBR plans approved in this proceeding will lead to such gains (Exhs. Unitil-RBH-1, at 25 (electric); Unitil-DJH-1, at 21 (gas)).[18]

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17 In D.P.U. 19-120, at 85-86, the Department rejected Boston Gas' decision to not apply a consumer dividend (i.e., effectively a zero percent consumer dividend) and instead set a consumer divided of 0.15 percent.

18 The Department also notes that Unitil has referred to the PBR plan approved in D.P.U. 22-22 as justification for several of the Company's proposals in the instant

Based on the above considerations, the Department finds that it is necessary to approve an explicit consumer dividend for the Company's electric and gas divisions, consistent with our precedent. Given the other components of the PBR mechanisms approved in this proceeding, the Department concludes that a consumer dividend of 25 basis points represents an appropriate explicit, tangible ratepayer benefit. D.P.U. 22-22, at 59; D.P.U. 20-120, at 83; D.P.U. 19-120, at 86; D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395. Further, we find that it is reasonable and appropriate for the consumer dividend to apply when inflation exceeds two percent.

f. K-bar Adjustment

As noted above, the Company proposes a K-bar adjustment that would allow additional revenues to be collected through the PBR adjustments, beginning July 1, 2025, to provide funding for capital investments for its electric division (Exh. Unitil-NAC-1, at 44; proposed M.D.P.U. No. 408, § 8.0 (electric)). The Department recognizes that, during the PBR term, Unitil will require flexibility to address the evolving energy and climate policies governing EDCs, as well as to maintain aging infrastructure and enhance resilience to address the impacts of climate change. To address these issues and keep pace with the Commonwealth's growing electrification needs and ambitious climate targets, the Company likely will need significant capital investments to develop a dynamic and modern distribution network. The Department

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proceeding (see, e.g., Exhs. Unitil-RBH-1, at 21-22 (electric); Unitil-MK-1, at 6-7, 64, 66; Unitil-NAC-1, at 28-31, 35-36, 43; Unitil-MK-Rebuttal at 3-4). NSTAR Electric voluntarily set its consumer dividend to 25 basis points as part of a compromise due to the expected cost-recovery potential of the K-bar mechanism. D.P.U. 22-22, at 59. As noted below, the Department approves the Company's K-bar component in this proceeding, and an explicit consumer dividend will ensure that some benefits of the K-bar-oriented PBR plan for the electric division are returned to ratepayers.

anticipates that Unitil may identify several capital projects to achieve these objectives during the development of its ESMP pursuant to G.L. c. 164, § 92B. The Department recognizes that required investments will go beyond the Company's grid modernization proposals approved in Second Grid Modernization Plans, D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B (2022) ("Second Grid Modernization"). The Department also finds that any capital investment program must encourage prudent investments while maintaining efficiencies and appropriate cost control measures. Further, while capital spending will be critical to achieve the Commonwealth's growing electrification needs and ambitious climate targets, a multi-year rate plan should have reasonable and predictable rate impacts for distribution customers, especially given the volatility of deregulated energy supply. Based on these considerations, the Department finds that the K-bar approach will provide sufficient funds to improve the resiliency and maintain the safety and reliability of the distribution system while maintaining efficient and appropriate cost controls. Therefore, the Department approves the incorporation of the K-bar in the Company's electric division PBR mechanism.

The Department has reviewed both a fixed historical average and annual rolling-average K-bar approach (Exhs. AG-DED-1, at 44; AG-DED-3, Sch. 7; Unitil-4 (2/1/24) (ESMP Excluded) (electric); Unitil-5 (ESMP Included) (electric); DOER 2-10, Att.(electric); RR-DPU-24, Att.). The Department finds that implementing a rolling-average K-bar balances providing a reasonable level of funding for capital improvements while protecting ratepayers from rate increases that have no corresponding benefits. A fixed historical average-based K-bar, on the other hand, would provide the Company with a predictable level of funding each year of the PBR term, but it would be unrelated to the Company's actual capital investments. While the

Department fully expects that Unitil will pursue system improvements annually, we acknowledge that large-scale capital projects may be difficult to forecast (Exh. Unitil-MK-1, at 4).

Further, historically, ratepayers have been financially protected from delays in capital spending due to regulatory lag. Distribution companies generally may not recover costs associated with capital improvements until after the Department completes a prudency review and determines that the capital investments are used and useful to customers. D.P.U. 20-120, at 155; D.P.U. 19-120, at 161-162; D.P.U. 17-05, at 85. The Department is concerned that using a fixed historical average to determine the increase in capital costs could expose customers to rate increases with no corresponding benefit if the Company fails to place projects into service in a timely manner. Thus, as we evaluate the design of the K-bar, the Department is mindful of balancing the Company's capital needs with the important consideration of the level of annual rate adjustments for customers. Based on these considerations, we find that the annual rolling-average K-bar provides an appropriate incentive for the Company to undertake necessary capital projects to meet its system needs and to adequately address relevant environmental and equity issues, as well as provides the flexibility required to adjust to project cost changes and to complete projects in a timely manner (Exhs. Unitil-RBH-1, at 19-20 (electric); Unitil-CGDN-1, at 72 (electric); Unitil-NAC-1, at 46-47; Unitil-MK-1, at 55-56).

Further, while the Department finds that an annual rolling-average K-bar provides ratepayers protection from annual rate increases without associated capital investments, the Department also finds it reasonable and appropriate to protect customers from substantial rate increases in the event that the Company makes significant capital investments in a single year without a full prudency review. To address this concern, Unitil has proposed to limit the amount of capital improvements that may be included in the annual K-bar adjustment. Specifically, the Company proposes an annual capital spending constraint of ten percent from the Forecasted Budget (Exh. AG 1-18, Att. 1; proposed M.D.P.U. No. 408, § 8.0 (electric)). The Department approves the Company's proposed ten percent of forecasted annual capital spending cap on K-bar net plant additions.

Beginning with the annual PBR adjustment effective July 1, 2025, the Company's actual capital costs for the calendar year prior to the year of the annual PBR plan filing (calendar year 2024 investments for rates effective July 1, 2025), shall be allowed for inclusion in the calculation of the K-bar average capital cost to the extent that the actual capital costs do not exceed the Forecasted Budget by more than ten percent, with no prudence review necessary at that time. Rate base included in the revenue requirement approved by the Department in this proceeding shall also be used in the K-bar calculations. The K-bar formula will calculate revenue support for the Company using the approved rate base associated with capital additions to determine the annual revenue support available in the respective PBR year. To the extent that the actual capital costs in the prior year, in aggregate, exceed the Forecasted Budget by more than ten percent, the K-bar allowance shall be capped at the ten-percent variance from the Forecasted Budget by excluding the variance from the K-bar calculation (proposed M.D.P.U. No. 408, § 8.0 (electric)). Projects with the lowest costs will be eligible for inclusion in the annual K-bar adjustment up to the ten-percent cap. The Department finds that this approach is fair to the interests of both ratepayers and the Company, is administratively efficient, and will avoid the burdensome review of an annual capital tracker mechanism.

In its 2025 PBR annual adjustment filing, the Company shall calculate the K-bar adjustment for effect July 1, 2025, using the five-year average of actual plant additions placed in service from 2020 through 2024[19] (Exh. Unitil-4 (2/1/2024); proposed M.D.P.U. No. 408, § 8.0 (electric)). The K-bar adjustment for effect July 1, 2026, will calculate the K-bar using the five-year average of plant additions placed in service from 2021 through 2025 (proposed M.D.P.U. No. 408, § 8.0 (electric)). The K-bar adjustment for effect July 1, 2027, will calculate the K-bar plant additions using the five-year average of plant additions placed in service from 2022 through 2026 (proposed M.D.P.U. No. 408, § 8.0 (electric)). The five-year average will be updated in the same manner for each subsequent year that the K-bar remains in effect (proposed M.D.P.U. No. 408, § 8.0 (electric)). For the K-bar calculation, the depreciation rate shall be calculated by dividing the depreciation expense approved in the instant proceeding by the gross plant approved in the instant proceeding. The property tax rate shall be the property tax expense approved in the instant proceeding divided by the net utility plant in service approved in the instant proceeding. The return on rate base shall be the rate of return as shown in the division-specific Schedule 4 below.

The Department acknowledges the Company's arguments regarding ESMP investment recovery in the context of the PBR plan (Company Brief at 75-78). As noted above, the Department must issue its Order in D.P.U. 24-12 by August 31, 2024. In that docket, the Department will address the appropriate recovery mechanism to be used for ESMP investments. If the Department determines in that docket that Unitil may recover ESMP investment costs

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19 In Section V.B.5. below, the Department approves recovery of the Company's post-test-year capital additions for the electric and gas divisions.

through base distribution rates, the Company may include future ESMP investments in the rolling average K-bar calculation, beginning with ESMP investments placed in service in 2024. Further, any ESMP investments allowed to be recovered through base distribution rates would not be subject to the annual capital spending constraint of ten percent from the Forecasted Budget, so as to not unduly delay the implementation of those investments (Tr. 11, at 1144-1146). Further, if ESMP investments are to be recovered through base distribution rates, the Company shall track those investments separately and provide such information to the Department in the annual PBR adjustment filings, consistent with the filing requirements discussed in Section III.D.6. below.

The Department finds that K-bar design approved above will bring several benefits to customers over the Company's proposal. First, using a rolling average will reduce the K-bar revenue if Unitil (electric) does not timely complete and place in-service projects prior to the next K-bar adjustment. The prospect of less K-bar revenue should incentivize the Company to complete projects in a timely manner and will limit customer exposure to costs associated only with projects actually completed. Further, the spending cap will benefit customers by limiting potential rate increases. Finally, a rolling K-bar is administratively efficient, as it is a formulaic adjustment.

The Department finds, consistent with D.P.U. 22-22, that the rolling-average K-bar mechanism will, given prudent management and decision making, provide the Company with adequate levels of revenue to support the capital investment that will be required in the coming years, while adhering to PBR principles. D.P.U. 22-22, at 66. With the approval of the K-bar mechanism, the Department expects a reasonable level of stability in Unitil's electric division capital project spending over the PBR plan term, as opposed to a disproportionate amount of spending in certain years, such as a proposed test year in the event Unitil files a new base distribution rate case upon expiration of the PBR plan term. The burden will be on the Company to manage expenditures and plan accordingly to keep pace with capital investment while developing and building a distribution network capable of supporting the Commonwealth's decarbonization goals. As part of its annual PBR filings, Unitil shall file a forecast of the capital projects planned to go into service in the subsequent year, and the associated costs of those projects, for informational purposes. Additionally, Unitil will file the actual distribution plant additions for the year prior to the annual PBR filing that will be the basis of the K-bar net plant additions. For example, in its 2025 annual PBR filing, Unitil shall file its forecasted 2026 planned capital projects expected to be in service. Then, in its 2026 annual PBR filing, Unitil will make an informational filing of its actual 2025 capital additions placed in service by the end of the first quarter of 2026. These informational filings will assist the Department and stakeholders to monitor Unitil's (electric) progress on achieving the Commonwealth's 2050 climate targets, as well as increase transparency to stakeholders, provide a measure of accountability in the Company's decision making, and provide a check on the accuracy of the Company's projected capital spending.

g. ESM and Reopener Provision

For both its electric and gas divisions, the Company proposes an asymmetrical ESM that would trigger a sharing with customers on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) where the computed distribution ROE exceeds 100 basis points above the ROE authorized in this proceeding (Exhs. Unitil-RBH-1, at 28-29 (electric);

Unitil-DJH-1, at 23 (gas); Unitil-NAC-1, at 48-50). The Company proposes that for any year in which the ROE is above or below the bandwidth, the percentage of earnings that is to be shared with customers would be credited to customers in the succeeding year and that the impact of this prior year adjustment would be excluded from the calculation of the subsequent year's sharing (Tr. 5, at 482-483).

The Department has found that ESMs may be integral components of incentive regulation plans, as they provide an important backstop to the uncertainty associated with setting the productivity factor. D.P.U. 17-05, at 400; D.P.U. 96-50 (Phase I) at 325; D.P.U. 94-50, at 197 & n.116. An ESM offers important protection for ratepayers in the event that expenses increase at a rate much lower than the revenue increases generated by the PBR. D.P.U. 18-150, at 70; D.P.U. 17-05, at 400; Western Massachusetts Electric Company, D.P.U. 10-70, at 8 n.3 (2011); D.T.E. 05-27, at 404-405. For this reason, the Department finds that there is a significant benefit to implementing an ESM as part of the PBR mechanism approved in this case.

The Company developed the proposed ESM in alignment with recent Department precedent (Exhs. Unitil-RBH-1, at 28 (electric); Unitil-DJH-1, at 23 (gas)). The Department has traditionally found that a PBR term of five years warrants an asymmetrical ESM with upside sharing with customers but no downside adjustments. D.P.U. 18-150, at 70-71; D.P.U. 17-05, at 400-401. Further, the Department has approved ESMs with deadbands of 100 basis points or greater. D.P.U. 22-22, at 70; D.P.U. 19-120, at 89; D.P.U. 18-150, at 71-72; D.P.U. 17-05, at 401; D.T.E. 05-27, at 405; D.T.E. 03-40, at 500; D.P.U. 96-50 (Phase I) at 326.

In this Order, the Department has approved a PBR plan term of five years for Unitil's electric and gas operating divisions. As such, we find it appropriate to approve an asymmetrical

ESM with no downward adjustment. Specifically, the ESM will have a deadband of 100 basis points above the Company's authorized ROE. If the Company's actual ROE exceeds the authorized ROE by more than 100 basis points, the earnings above the deadband will be shared 75 percent with customers and 25 percent with the Company.

The Company's reopener provision would allow the Company to petition the Department to revisit the PBR plans if the Company's earned ROE falls to or below 6.50 percent in any one year, or 7.00 percent for two consecutive years (Exhs. Unitil-RBH-1, at 29 (electric); Unitil-DJH-1, at 23 (gas); Unitil-MK-1, at 68-69). The Department previously rejected a form of a reopener in for NSTAR Electric. D.P.U. 22-22, at 67-68. The Department finds that the Company's stay-out provision would be essentially meaningless with the inclusion of a reopener and would blunt the incentives for cost-control that are supposed to be fostered under a PBR plan. Accordingly, the Department rejects the Company's proposed reopener provision for both its electric and gas divisions.

h. Exogenous Cost Factor

As noted above, the Company proposed to include in the PBR adjustment formula for its electric and gas divisions an exogenous cost provision, i.e., Z factor (Exh. Unitil-NAC-1, at 47-48; proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)). The Company proposed that to be eligible for exogenous cost recovery the cost change must: (1) be beyond the Company's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) be unique to the electric (or natural gas) distribution industry as opposed to the general economy; and (4) meet a threshold of "significance" for qualification (Exh. Unitil-NAC-1, at 47-48; proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)). The Company proposed the significance threshold for exogenous costs to be set at $110,000 for the electric division and $60,000 for the gas division in 2024 and adjusted annually by the change in GDP-PI (Exh. Unitil-NAC-1, at 48; proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)).

In D.P.U. 94-158, at 62, the Department recognized that there may be exogenous costs, both positive and negative, that are beyond the control of a company and, where the company was subject to a stay-out provision, these costs may be appropriate to recover (or return) through the PBR mechanism. The Department has defined exogenous costs as positive or negative cost changes that are beyond a company's control and are not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173. The Department has cautioned against expansion of these categories to a broader range. D.P.U. 96-50 (Phase I) at 290-291; D.P.U. 94-158, at 61-62. The Company proposed to adopt a definition of exogenous costs that is consistent with the definition adopted by the Department in D.P.U. 94-50 (Exh. Unitil-NAC-1, at 47-48; proposed M.D.P.U. No. 408, §§ 3-4 (electric); proposed M.D.P.U. No. 274, § 1 (gas)). Accordingly, the Department finds that the Company's proposed definition of exogenous costs in this instance is appropriate.

As noted above, the Company proposed an exogenous cost significance threshold of $110,000 for the electric division and $60,000 for the gas division for each individual event for the first PBR year ending June 30, 2025, subject to annual adjustments thereafter based on changes in GDP-PI (Exh. Unitil-NAC-1, at 48; proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)). Although the Department must consider the facts and circumstances of each case, the Department has previously found that an exogenous cost significance threshold was reasonable where it was equal to a multiple of 0.001253 times a company's total operating revenues. D.P.U. 22-22, at 73; D.P.U. 20-120, at 97; D.P.U. 19-120, at 93-94; D.P.U. 18-150, at 66-67; D.P.U. 17-05, at 397; D.T.E. 03-40, at 491; D.T.E. 01-56, at 22-46; D.P.U. 96-50 (Phase I) at 293. Consistent with our precedent and facts of this case, the Department finds that $110,000 for the electric division and $60,000 for the gas division is a reasonable exogenous cost significance threshold for the Company, which has total operating revenues of $88,963,526 and $47,823,978, respectively, and is implementing for each division a multi-year PBR plan with the overall design approved herein (Exhs. Unitil-NAC-1, at 48; AG 1-2, Att. 6.04, at 98 (electric); AG 1-2, Att. 7.04, at 41 (gas); proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)).

In addition, the Company has proposed, and we have allowed, that the exogenous cost significance threshold be subject to annual adjustments based on changes in GDP-PI as measured by the U.S. Bureau of Economic Analysis (Exh. Unitil-NAC-1, at 48; proposed M.D.P.U. No. 408, § 9 (electric); proposed M.D.P.U. No. 274, § 9 (gas)). The Department is satisfied that this proposal appropriately considers the effects that inflation will have on the threshold in the later years of the PBR term. D.P.U. 22-22, at 74; D.P.U. 19-120, at 94; D.P.U. 18-150, at 67; D.P.U. 17-05, at 398; D.T.E. 01-56, at 11-14; <u>Eastern Enterprises/Colonial Gas Company</u>, D.P.U. 98-128, at 56-57 (1999). Accordingly, we set the Company's threshold for exogenous cost recovery at $110,000 for the electric division and $60,000 for the gas division, for each individual event in the first PBR year, ending June 30, 2025, subject to annual adjustments thereafter based on changes in GDP-PI as used in the PBR mechanism.

Exogenous cost recovery requires that a company provide supporting documentation and rationale to the Department for a determination as to the appropriateness of the proposed exogenous cost. Boston Edison Company, D.T.E. 99-19, at 25 (1999); D.P.U. 98-128, at 55; Bay State Gas Company, D.T.E. 98-31, at 17-18 (1998). Additionally, any company seeking recovery of an exogenous cost bears the burden of demonstrating the propriety of the exogenous cost and that the proposed exogenous cost change is not otherwise reflected in the GDP-PI. D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 171. For these reasons, the Department does not prejudge the qualification of any future events as exogenous costs and will consider each proposal for recovery of exogenous costs on a case-by-case basis. At the time that it seeks exogenous cost recovery, the Company must demonstrate that the event meets both the definition and threshold for exogenous costs approved herein.

i. PBR Adjusted Revenues

The Department has found it suitable to modify PBR plans or simplified incentive plans to exclude adjustments for certain types of costs. See, e.g., NSTAR Electric Company, D.P.U. 23-92, Exhs. ES-ANB/DJB at 14; ES-ANB/DJB-1, at 3 (2023) (removing solar expansion program costs and certain storm fund costs from PBR adjustment); D.P.U. 22-22, at 76-77 (solar expansion program costs to be removed from PBR adjustment); D.P.U. 18-150, at 73 (excluding solar facility costs from PBR adjustment); NSTAR Electric Company, D.P.U. 18-101, Exhs. NSTAR-DPH at 18; NSTAR-DPH-1, at 1 (2018) (certain storm costs excluded from PBR adjustment); D.P.U. 17-05, at 392 (removal of certain grid modernization investments); NSTAR Electric Company and NSTAR Gas Company, D.P.U. 08-56/D.P.U. 09-96, at 18-19 (2010) (removal of certain pension and post-retirement benefits other than pension ("PBOP") costs).

In Section XIII.D.2. below, the Department approves the transfer of costs from the Company's Solar Cost Adjustment ("SCA") tariff into base distribution rates. As explained in further detail in Section XIII.D. below, the SCA tariff recovers costs and credits revenues to customers associated with the Company's operation of a solar facility at Sawyer Passway in the City of Fitchburg ("Sawyer Passway Project"). The Department finds that it is appropriate to remove these costs from the PBR mechanism adjustment calculation and maintain the revenues associated with the solar facility at the level approved in this proceeding until the Company's next base distribution rate case. The Sawyer Passway project represents power generation costs, rather than distribution costs. Further, the costs associated with the Sawyer Passway project fall outside the Company's regular operations of safely and reliably delivering electricity to customers. Accordingly, even if the Company does not replace these assets when they retire, it could perversely continue to collect a revenue target that increases annually by the PBR mechanism. The Department, therefore, directs the Company to revise the definition of PBR revenue to exclude the costs of the Sawyer Passway project.

Further, the Company's proposed PBR tariff for its electric division notes that the "Major Storm Reserve Fund Contribution and the Storm Resiliency Program Funding" shall be excluded from the PBR revenue requirement (proposed M.D.P.U. No. 408, § 4.0(2) (electric)). As explained in further detail in Section IX. below, the Company's major storm reserve fund ("storm fund") contribution includes the annual storm fund contribution and the annual O&M

expense for storm events collected through base distribution rates (proposed M.D.P.U. No. 408, § 4.0(23) (electric)). Based on its initial proposals in this proceeding, the Company proposed to annually exclude from the PBR revenue requirement $416,000 in storm fund contribution (proposed M.D.P.U. No. 408, § 4.0(23) (electric)). The Department finds it appropriate to exclude the storm fund contribution from the PBR revenue requirement. In Sections IX.D.3.b. & IX.D.3.c. below, however, the Department approves a total storm fund contribution of $383,000 annually.[20] Therefore, the Company shall revise its PBR tariff to reflect the adjusted storm fund contribution.

As set forth in further detail in Section VIII.C. below, Unitil's Storm Resiliency Program ("SRP") funding is an annual amount recovered through base distribution rates associated with the Company's storm resiliency pilot approved in Fitchburg Gas and Electric Light Company, D.P.U. 13-90 (2014). The current annual amount is $501,445. D.P.U. 13-90, at 21. Based on its initial proposals in this proceeding, the Company proposed to annually exclude from the PBR revenue requirement $666,096 in SRP funding, which the Department approves in Section VIII.C.4. below (proposed M.D.P.U. No. 408, § 4.0 (31) (electric)). The Department, however, denies the Company's proposal to annually reconcile SRP costs. Thus, unlike the storm fund mechanism, the Company will be unable to seek recovery of storm resiliency costs above the representative level in base distribution rates. Given this decision, we find that the SRP funding should not be excluded from the PBR revenue requirement, and we direct the Company to revise its PBR tariff accordingly.

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20 The $383,000 comprises $267,000 in annual storm fund contribution and $116,000 in annual O&M expense.

6. Conclusion

In the sections above, the Department has reviewed the Company's PBR plan proposals. We conclude that the proposed PBR plans, as modified above, are likely to advance the Commonwealth's important climate objectives, and to promote the Department's goals of safe, secure, reliable, equitable, and least-cost service and economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. See, e.g., 2021 Climate Act; Green Communities Act; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298; An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, § 36; Green Communities Expansion Act, § 83A; Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016); G.L. c. 25, § 1A.

In addition, we conclude that the PBR plans, as approved, will provide the Company with greater incentives to reduce costs than currently exist and should result in benefits to customers that are greater than would be present under current regulation. Further, the Department is convinced that the PBR plans, as approved, better satisfy our public policy goals and statutory obligations, including promotion of a safe and reliable electric distribution system, and of the Commonwealth's clean energy mandates and goals.

With the modifications required herein, the Department finds that the PBR plans appropriately balance ratepayer and shareholder risk, are in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164, § 94. Accordingly, the Department approves the PBR plans for the Company's electric and gas divisions, subject to the modifications above.

The Company, in its compliance filing, shall submit revised PBR plan tariffs for the electric and gas divisions consistent with the findings in this Order.

Further, the Company shall submit annual PBR adjustment filings for the electric and gas divisions, including all information and supporting schedules necessary for the Department to review the proposed PBR adjustments for the subsequent rate year. Such information shall include the results and supporting calculations of the PBR adjustment factor formula, descriptions and accounting of any exogenous events, and an earnings sharing calculation for the year, two years prior to the rate adjustment. In addition, the Company shall file revised summary rate tables reflecting the impact of applying the base distribution rate changes provided in the PBR adjustment filing.

Unitil proposed to submit its annual PBR adjustment filings on or before March 15 for its electric division and on or before May 15 for its gas division, for rates effective July 1. The Department has previously determined that a minimum of three months is needed to provide the Department and intervenors an opportunity to determine the appropriateness of PBR and other similar filings. Eversource Gas Company of Massachusetts, D.P.U. 22-122, at 11 n.6 (2022); NSTAR Gas Company, D.P.U. 22-121, at 16 n.14 (2022). Thus, we direct the Company to submit its annual PBR adjustment filings for both the electric and gas division on or before March 1 of each year, commencing in 2025 and continuing for the five-year term of the PBR. Consistent with our findings above, the PBRs shall continue in effect for a total of five consecutive years starting July 1, 2024, with the last adjustments taking effect on July 1, 2029, subject to the findings set forth above.

IV. PBR SCORECARD METRICS

A. Introduction

The Company proposes a suite of scorecard metrics for its electric and gas divisions, organized into the following high-level categories: (1) customer satisfaction and engagement (electric and gas divisions); (2) peak demand reduction (electric division); (3) safety and reliability (gas division); (4) climate transition and greenhouse gas ("GHG") emissions reduction (electric and gas divisions); and (5) emissions reductions (gas division) (Exhs. Unitil-RBH-1, at 29-30 (electric); Unitil-ESMP-1, at 7-10 (Rev.) (electric); Unitil-ESMP-Rebuttal at 17-18 (electric); Unitil-DJH-1, at 24-25 (gas); Unitil-GSMP-1, at 6-9 (gas); Unitil-MK-1, at 8).[21]

The Company states that its proposed scorecard metrics are aligned with the Department's policy objectives of improving customer service, safety and reliability, reducing system peak demand, and strategic planning for climate adaptation, and that the metrics will allow the Department and stakeholders to track the benefits that accrue over the PBR term (Exhs. Unitil-ESMP-1, at 8 (Rev.) (electric); Unitil-RBH-1, at 29-30 (electric); Unitil-ESMP-Rebuttal at 7; 21-23; 29 (electric); Unitil-DJH-1, at 24 (gas); Unitil-GSMP-1, at 28 (gas); Unitil-GSMP-Rebuttal at 7; Unitil-MK-1, at 8).

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21 In response to the Attorney General's recommendation, the Company proposed an additional metric to track termination of service to low-income customers for its electric division (Exhs. Unitil-ESMP-Rebuttal at 4, 17-18 & n.5 (electric); AG-DED-1, at 58). Unitil did not propose the same metric for the gas division because the Company does not have census-level data for gas customers (Exh. DPU 43-8 (gas)).

B. Proposed Scorecard Metrics

1. Customer Satisfaction and Engagement Metrics (Electric and Gas Divisions)

a. Introduction

For its electric and gas divisions, Unitil proposes a suite of metrics addressing customer satisfaction and engagement (Exhs. Unitil-ESMP-1, at 9, 10-19 (Rev.) (electric); Unitil-GSMP-1, at 8, 19-28 (gas)). As discussed below, most of these metrics apply to both the Company's electric and gas divisions, while a few are division-specific. Additionally, in response to a recommendation by the Attorney General, Unitil proposes to include a scorecard metric to track termination of electric service to low-income customers (Exh. Unitil-ESMP-Rebuttal at 17 (electric)).

Additionally, the Company is in the process of implementing a large information technology initiative called "Project Phoenix" (Exhs. Unitil-ESMP-1, at 13 (Rev.) (electric); Unitil-GSMP-1, at 23 (gas)). The Company states the project includes an upgraded web portal that is designed, among other things, to provide a more robust customer experience through new customer information system functionality along with an enhanced payment platform (Exhs. Unitil-ESMP-1, at 13 (Rev.) (electric); Unitil-GSMP-1, at 23 (gas)). The Company expects Project Phoenix to be complete by July 1, 2024 (Exhs. DPU 28-10 (electric); DPU 23-3 (gas)). As discussed below, various aspects of the Company's proposed metrics depend on completing Project Phoenix (Exhs. Unitil-ESMP-1, at 14-15 (Rev.) (electric); Unitil-GSMP-1, at 22-23 (gas)).

b. Customer Satisfaction with Customer Service Metric (Electric and Gas Divisions)

Unitil's proposed customer satisfaction with customer service metric is based on a survey conducted by the Company's cloud-based phone system and applies to electric and gas customers (Exhs. Unitil-ESMP-1, at 12-13 (Rev.) (electric); DPU 52-2 (electric); Unitil-GSMP-1, at 21-22 (gas); DPU 40-1 (gas)). All customers who elect to speak to a customer service representative by phone are provided with the option to take the survey at the end of their call (Exhs. DPU 32-5 (electric); DPU 27-3 (gas)). During the survey, the customer is asked six questions about overall call satisfaction: (1) the overall experience with the call; (2) the courtesy demonstrated by the customer service representative; (3) the quality of the response of the customer service department; (4) the level of effort put forth by the agent in assisting the customer; (5) the knowledgeability of the customer service representative; and (6) whether the customer needed to contact the Company more than once to resolve the issue (Exhs. DPU 32-5 (electric); DPU 27-3 (gas)). The customer is asked to respond to these questions on a scale from one to seven where seven describes the highest level of satisfaction, and the percentage of responses with a rating of five to seven are categorized as "satisfied" (Exhs. Unitil-ESMP-1, at 12 (Rev.) (electric); DPU 32-5 (electric); Unitil-GSMP-1, at 21-22 (gas); DPU 27-3 (gas)). The Company's current three-year average is 89 percent of callers qualifying as "satisfied" (Exhs. Unitil-ESMP-1, at 12 (Rev.) (electric); Unitil-GSMP-1, at 22 (gas)). The Company proposes to alter the scale in 2024 so that satisfaction is ranked from zero to ten, and the percentage of responses with a rating of six to ten are categorized as "satisfied" (Exhs. Unitil-ESMP-1, at 12 (Rev.) (electric); DPU 32-5 (electric); Unitil-GSMP-1, at 22 (gas); DPU 27-3 (gas)). The Company proposes a target of 85 percent of calls scoring high enough to qualify as "satisfied" (Exhs. Unitil-ESMP-1, at 9, 12 (Rev.) (electric); Unitil-GSMP-1, at 22 (gas)).

c. Digital Engagement Metrics (Electric and Gas Divisions)

The Company proposes a suite of metrics in the area of digital engagement, with four metrics applicable to the electric and gas divisions, and one metric applicable only to the electric division (Exhs. Unitil-ESMP-1, at 9, 13-19 (Rev.) (electric); Unitil-GSMP-1, at 8, 22-28 (gas)). First, the Company proposes a metric to track the number of MyUnitil profiles that are enabled over the course of the PBR term (Exhs. Unitil-ESMP-1, at 16 (Rev.) (electric); Unitil-GSMP-1, at 25-26 (gas)). A MyUnitil profile allows customers to access their billing history, payment history, usage history, email, SMS notifications, and self-service forms (Exhs. Unitil-ESMP-1, at 16 (Rev.) (electric); DPU 32-6 (electric); Unitil-GSMP-1, at 25-26 (gas); DPU 27-6 (gas)). Unitil does not propose benchmarks or targets for this metric at this time, but the Company plans to do so in a future annual PBR adjustment filing once functionality is enabled by Project Phoenix and the Company can compile sufficient data to support benchmarks and targets (Exhs. Unitil-ESMP-1, at 14, 16 (Rev.) (electric); Unitil-GSMP-1, at 25-26 (gas)).

Second, the Company proposes a metric to track and report on the number of self-service interactions that are enabled over the course of the PBR term (Exhs. Unitil-ESMP-1, at 17 (Rev.) (electric); Unitil-GSMP-1, at 26 (gas)). As examples of self-service interactions, the Company proposes to include live web chats with a customer service representative, new service requests, service disconnection, transfer of service, updates to customer mailing addresses, requests to enroll and update the auto-pay option, and requests to initiate alternative payment plans (Exhs. Unitil-ESMP-1, at 17 (Rev.) (electric); Unitil-GSMP-1, at 26 (gas)). The Company intends to report monthly volumes by transaction type on an annual basis, and it will propose specific targets for this metric in a future annual PBR adjustment filing once functionality is enabled by Project Phoenix and the Company can collect sufficient data (Exhs. Unitil-ESMP-1, at 17 (Rev.) (electric); Unitil-GSMP-1, at 26 (gas)).

Third, the Company states that it is currently working with its vendors to develop a metric for notifications and alerts once Project Phoenix is completed and functionality has been tested (Exhs. Unitil-ESMP-1, at 18 (Rev.) (electric); Unitil-GSMP-1, at 27 (gas)). The Company expects to propose the metric in a future annual PBR adjustment filing (Exhs. Unitil-ESMP-1, at 18 (Rev.) (electric); Unitil-GSMP-1, at 27 (gas)). The Company's notifications and alerts functionality is intended to enable customers to enroll in payment notifications, appointment reminders, and a high usage or bill alert (Exhs. Unitil-ESMP-1, at 17-18 (Rev.) (electric); Unitil-GSMP-1, at 26-27 (gas)).

Fourth, the Company states that it is also working with vendors to develop a metric for mobile applications once Project Phoenix is completed (Exhs. Unitil-ESMP-1, at 19 (Rev.) (electric); Unitil-GSMP-1, at 27-28 (gas)). The Company expects to propose the metric in a future annual PBR adjustment filing (Exhs. Unitil-ESMP-1, at 19 (Rev.) (electric); Unitil-GSMP-1, at 28 (gas)). The mobile application will allow customers to pay their bill, view utility usage, view billing and payment history, enroll in paperless billing, view alerts, update their MyUnitil profile information, obtain electronic access to the customer newsletter, access smart meter data, and access information on ways to save on their bill (Exhs. Unitil-ESMP-1, at 19 (Rev.) (electric); Unitil-GSMP-1, at 27 (gas)).

Finally, Unitil states that it is working with vendors to develop an electric division metric for outage notification once Project Phoenix is completed (Exhs. Unitil-ESMP-1, at 19 (Rev.) (electric)). The Company expects to propose the metric in a future annual PBR adjustment filing (Exh. Unitil-ESMP-1, at 19 (Rev.) (electric)). Outage notification functionality will allow the Company to notify customers when their service is out and provide them with an estimated time of restoration (Exh. Unitil-ESMP-1, at 18-19 (Rev.) (electric)).

d. Average Speed of Answer of Gas Emergency Calls Metric (Gas Division)

Unitil proposes a metric to measure the Company's call response time to emergency calls that report gas leaks and odors (Exh. Unitil-GSMP-1, at 8, 20 (gas)). The proposed metric would measure, in seconds, the time it takes for a customer service representative to answer a customer call reporting a gas leak, odor, or other emergency (Exh. Unitil-GSMP-1, at 20 (gas)). The Company reports that its average response time for gas emergency calls over the last three years is just over four seconds (Exh. Unitil-GSMP-1, at 20 (gas)). As a performance target for the proposed metric, the Company proposes the five-year average response time to gas emergency calls will not exceed ten seconds over the PBR plan term (Exh. Unitil-GSMP-1, at 20 (gas)).

e. Low-Income Service Termination Metric (Electric Division)

In response to a recommendation from the Attorney General during the proceeding, Unitil proposes to develop a metric to track termination of electric service to low-income customers (Exhs. Unitil-ESMP-Rebuttal at 4, 17-18 & n.5 (electric); AG-DED-1, at 58). The proposed metric would provide monthly data (on a going-forward basis) regarding low-income customer service terminations, consistent with the low-income termination metric approved in D.P.U. 22-22 (Exh. Unitil-ESMP-Rebuttal at 17-18 (electric)). According to the Company, the data would include the percent and number of low-income customers by census tract areas who had their service terminated for non-payment and who have accounts with past-due balances at levels eligible for disconnect (Exh. Unitil-ESMP-Rebuttal at 17-18 (electric)).

2. Peak Demand Reductions Metrics (Electric Division)

Unitil proposes four metrics in the category of peak demand reduction (Exh. Unitil-ESMP-1, at 9, 20-28 (Rev.) (electric)). First, the Company proposes to measure the battery output of Company-owned storage at a substation in the Town of Townsend, Massachusetts ("Townsend substation").[22] Unitil's proposed scorecard metric would measure battery output from the Townsend substation during transformer peak load on days that transformer load exceeds 80 percent of its rating (Exh. Unitil-ESMP-1, at 21 (Rev.) (electric)). The Company's goal is to reduce the Townsend substation transformer load by 500 kW during peak hours (Exhs. Unitil-ESMP-1, at 9, 20-21 (Rev.) (electric); Unitil-KSTB-1, at 24-26 (electric); DPU 20-1 (electric)). Peak demand reduction will be measured by metering data at the storage site and the Townsend substation transformer (Exh. Unitil-ESMP-1, at 21 (Rev.) (electric)).

[22] In 2021, the Company installed an energy storage (i.e., lithium battery) and management system at the Townsend substation to help maximize the efficiency of renewable energy and lower costs in the region (Exh. Unitil-KSTB-1, at 25 (electric)). The battery project was designed to use the energy stored at the Townsend substation to reduce load during key hours of the day (Exh. Unitil-KSTB-1, at 25 (electric)). Thus, the battery project serves as a "non-wires alternative" and provides load-shifting and load-shaping capabilities, thereby deferring the installation of additional substation transformer capacity at the Townsend substation (Exh. Unitil-ESMP-1, at 21 (Rev.) (electric)). The Townsend battery project was placed in service in 2021 and has been reviewed by the Department for prudency. Fitchburg Gas and Electric Light Company, D.P.U. 22-82-A at 7 & Exh. Unitil-DJH-2, at 1, line 24 (2023).

Second, the Company proposes a Volt-Var Optimization ("VVO") metric. According to Unitil, VVO technology enables the Company to manage voltage levels and reactive power to achieve efficient electric grid operations by reducing system electrical losses, peak demand, and/or energy consumption (Exh. Unitil-ESMP-1, at 21-22 (Rev.) (electric)). Unitil's VVO investments include the installation of automated controls on voltage and reactive power equipment on all distribution circuits in the Company's service area over the next five to ten years (Exh. Unitil-ESMP-1, at 22 (Rev.) (electric)).[23]

Unitil's proposed VVO scorecard metric would measure peak load reduction resulting from VVO technology at the Company's seven substations[24] once the VVO technology is installed at each substation (Exh. Unitil-ESMP-1, at 9, 22-23 (Rev.) (electric)). The Company proposes a target level two-percent peak reduction at each substation (Exh. Unitil-ESMP-1, at 9, 22-23 (Rev.) (electric)). The Company uses a three-year average annual peak load as the baseline against which to measure the proposed two-percent target reduction (Exh. Unitil-ESMP-1, at 23 (Rev.) (electric)).

Third, the Company proposes an energy efficiency metric to measure the cumulative "Net Summer kW" reductions associated with the Company's interventions in the MassSave

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[23] The Company reports that it has implemented VVO on the circuits served from the Townsend substation, and that testing is underway to verify the VVO system is producing the expected benefits (Exh. Unitil-ESMP-1, at 22 (Rev.) (electric)). The Company states that it has begun the installation and commissioning of field equipment on the circuits served from two other substations – one on Summer Street in Fitchburg and the other in Lunenburg (Exh. Unitil-ESMP-1, at 22 (Rev.) (electric)).

[24] The Company has substations in Townsend, Lunenburg, Summer Street, West Townsend, Beech Street, Pleasant, and Princeton Road (Exh. Unitil-ESMP-1, at 22-23 (Rev.) (electric)).

energy efficiency programs for the period 2022-2028 (Exh. Unitil-ESMP-1, at 26-27 (Rev.) (electric)). The Company proposes a cumulative target level 3.17 MW reduction in Net Summer kW reductions by 2028 (Exh. Unitil-ESMP-1, at 27 (Rev.) (electric); Tr. 6, at 530-531). To establish a baseline against which to measure the proposed target, Unitil used actual results from its energy efficiency program in 2022 (Exh. Unitil-ESMP-1, at 26 (Rev.) (electric)). The target was developed from Department-approved energy efficiency plan values for 2023 and 2024, and the Company's estimated values for 2025-2028 (Exh. Unitil-ESMP-1, at 26-27 (Rev.) (electric)).

Finally, the Company proposes an active demand response ("ADR") metric to measure the peak demand impact of demand response measures implemented by the Company. Unitil states that its ADR programs lower system peak demand by actively calling on customers to briefly reduce their electric loads during targeted periods of high system demand either through direct control or curtailment measures (Exh. Unitil-ESMP-1, at 24 (Rev.) (electric)). The Company relies on two primary ADR strategies: (1) direct control strategies, such as dispatching controllable, customer-owned, behind-the-meter technologies (e.g., wireless thermostats and storage devices); and (2) curtailment efforts, such as offering incentives to customers who, with prior notice, reduce load when called upon to do so (Exh. Unitil-ESMP-1, at 24-25 (Rev.) (electric)). The Company has set a target of a 0.25 MW reduction annually (Exh. Unitil-ESMP-1, at 9, 24-26 (Rev.) (electric)). To establish a baseline against which to measure the proposed target, Unitil used actual results from its energy efficiency program in 2022 (Exh. Unitil-ESMP-1, at 26 (Rev.) (electric)). The target was developed from Department-approved energy efficiency plan values for 2023 and 2024 (Exh. Unitil-ESMP-1, at 26 (Rev.) (electric)).

3. Safety and Reliability Metrics (Gas Division)

For its gas division, Unitil proposes four metrics under the safety and reliability category (Exh. Unitil-GSMP-1, at 7, 10-19 (gas)). First, the emergency response rate within 45 minutes metric is designed to track the time elapsed, in minutes, from when a report of a gas odor is received to when a Unitil representative arrives at the scene (Exh. Unitil-GSMP-1, at 11 (gas)). Unitil's average response rate during the five-year period 2018 through 2022 is approximately 99 percent of calls responded to within 45 minutes (Exh. Unitil-GSMP-1, at 11 (gas)). For purposes of the proposed metric, the Company proposes to commit to a target of 95 percent of calls responded to within 45 minutes (Exh. Unitil-GSMP-1, at 11 (gas)).

Second, the total damages per 1,000 Dig Safe tickets metric is designed to track the number of excavation damages per 1,000 Dig Safe tickets (Exh. Unitil-GSMP-1, at 12-13 (gas)). The Company's baseline for this metric is 1.95 damages per 1,000 Dig Safe tickets based on a five-year average (2018 through 2022) plus one standard deviation (Exh. Unitil-GSMP-1, at 13 (gas)). As a performance target, the Company proposes that the five-year average of total damages per 1,000 tickets will not exceed the baseline of 1.95 damages per 1,000 tickets (Exh. Unitil-GSMP-1, at 13 (gas)). Further, as part of this metric, Unitil proposes to track and report on: (1) total at-fault damages per 1,000 Dig Safe tickets; (2) total at-fault damages due to records per 1,000 Dig Safe tickets; (3) total at-fault damages due to human error per 1,000 Dig Safe tickets; and (4) total damages not-at-fault per 1,000 Dig Safe tickets (Exh. Unitil-GSMP-1, at 15 (gas)).

Third, Unitil proposes a Grade 2 leak metric to measure the Company's commitment to repair or eliminate Grade 2 leaks within nine months of detection (Exh. Unitil-GSMP-1, at 15-16 (gas)). Under this proposed metric, the Company would measure the number of days from the date a Grade 2 leak is reported to the date the leak is repaired (Exh. Unitil-GSMP-1, at 16 (gas)).

Finally, the proposed pipeline safety management system ("PSMS") implementation metric would measure the progress of the Company's pipeline safety efforts (Exh. Unitil-GSMP-1, at 17 (gas)). The PSMS was developed by the American Petroleum Institute Recommended Practice 1173 with input from the National Transportation Safety Board, the Pipeline and Hazardous Materials Safety Administration, states, and industry representatives (Exh. Unitil-GSMP-1, at 16 (gas)). The American Petroleum Institute Recommended Practice 1173 is a management system that is designed to strengthen an organization's safety culture and is organized around certain essential elements for the comprehensive and systematic management of safety-related activities (Exh. Unitil-GSMP-1, at 16 (gas)).[25] The Company would track its progress using a PSMS Maturity Model, which has five levels that evaluate an operator's progress in the implementation and effectiveness of its PSMS: planning, developing, implemented, sustaining, and improving (Exh. Unitil-GSMP-1, at 18-19 (gas)). The Company proposes a target of achieving the "implemented" stage by the end of the PBR term (Exh. Unitil-GSMP-1, at 19 (gas)). Unitil proposes to engage a third party in 2024 to perform an independent assessment of the Company's PSMS implementation and that assessment will set a baseline for this metric (Exhs. Unitil-GSMP-1, at 19 (gas); DPU 23-5 (gas)).

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25 The essential elements are leadership and management commitment; stakeholder engagement; risk management; operational controls; incident investigation, evaluation and lessons learned; safety assurance; management review and continuous improvement; emergency preparedness and response; competence, awareness, and training; and documentation and record keeping (Exh. Unitil-GSMP-1, at 16 (gas)).

4. Climate Transition and GHG Emissions Reductions Metric (Electric and Gas Divisions)

In 2020, Unitil Corporation established two enterprise-wide carbon reduction targets: a 50 percent reduction of direct (Scope 1) emissions[26] by 2030; and a net-zero target for direct emissions by 2050 (Exhs. Unitil-ESMP-1, at 29 (Rev.) (electric); Unitil-GSMP-1, at 32 (gas)). The Company states it is actively taking steps to meet these targets by, among other things, making building efficiency improvements, focusing emissions reduction efforts on the replacement of leak-prone pipe, and transitioning to alternative fuels and electrification for Company-owned vehicles (Exhs. Unitil-ESMP-1, at 29-30 (Rev.) (electric); Unitil-GSMP-1, at 32 (gas)). Unitil completes an annual GHG emissions inventory to monitor progress towards these targets and to assess the effectiveness of reduction initiatives (Exhs. Unitil-ESMP-1, at 30 (Rev.) (electric); Unitil-GSMP-1, at 32 (gas)).

In the instant case, the Company proposes a climate transition metric that will target a ten-percent reduction in Scope 1 emissions by 2027 against a 2022 baseline (Exhs. Unitil-ESMP-1, at 10, 30 (Rev.) (electric); DPU 20-4 (electric); Unitil-GSMP-1, at 9, 32 (gas); DPU 6-10 (gas); DPU 25-6 (gas)). The proposed metric will report the Company's progress towards meeting the target on a Massachusetts-specific basis (Exhs. Unitil-ESMP-1, at 30-31 (Rev.) (electric); DPU 20-4 (electric); Unitil-GSMP-1, at 33 (gas); DPU 25-6 (gas)).

26 Scope 1 emissions are direct emissions resulting from the Company's use of fossil fuels or releases of GHG (i.e., fleet, heating, fugitive pipeline emissions) (Exhs. Unitil-ESMP-1, at 28 (Rev.) (electric); Unitil-GSMP-1, at 32 (gas)).

5. Emissions Reduction Metrics (Gas Division)

Unitil proposes two emissions reduction scorecard metrics (Exh. Unitil-GSMP-1, at 8, 28-31 (gas)). First, the Company proposes a metric that will measure progress in emissions reductions, in metric tons, associated with replacement of leak-prone distribution infrastructure through the Gas System Enhancement Plan ("GSEP") (Exh. Unitil-GSMP-1, at 8, 30 (gas)). The Company established a methane emissions baseline of 2,075 metric tons based on the Company's year-end 2018 distribution system emissions, which were reported to the Massachusetts Department of Environmental Protection ("MassDEP") in April 2019 (Exhs. Unitil-GSMP-1, at 30 (gas); DPU 25-2 & Atts. (gas)).[27] The Company's target for this metric is a 50 percent reduction to this baseline of methane emissions by year-end 2027 (Exh. Unitil-GSMP-1, at 30 (gas)).

Unitil proposes a second emissions reductions metric that will measure the time it takes the Company to repair Grade 3 leaks identified as having a significant environmental impact ("G3SEI") (Exh. Unitil-GSMP-1, at 8, 28 (gas)). The Company is committing to repair all G3SEI leaks located on non-GSEP infrastructure within twelve months of designation, which exceeds the requirement in the Department's regulations (Exh. Unitil-GSMP-1, at 8, 28, 30-31 (gas)).[28]

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[27] Natural gas system emissions on the Company's distribution system are measured pursuant to MassDEP regulations under 310 CMR 7.73 (Exhs. Unitil-GSMP-1, at 30 (gas); DPU 25-2 (gas)).

[28] Department regulations require the following timeframes for eliminating leak-extent designated Grade 3 leaks: (i) leak-extent designated leaks with a leak extent between 2,000 and 10,000 square feet shall be repaired or eliminated within two years of initial designation, provided that any such leaks located on a pipe scheduled for repair under the

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the Company's metrics do not meet the Department's established standards because they produce insufficient and inadequate information and do not measure the benefits attributable to the PBR plans (Attorney General Brief at 15-16, citing D.P.U. 22-22, at 115; D.P.U. 17-05, at 405). In this regard, she asserts that because the proposed metrics are not tied to PBR outcomes, they will not incentivize customer benefits (Attorney General Brief at 16).

Further, the Attorney General argues that due to the lack of penalties for substandard performance, the proposed metrics do not show that the Company is committed to achieving the policy objectives implicit in the metrics (Attorney General Brief at 16). Moreover, the Attorney General claims that the Company's proposed PBR metrics should include financial penalties to rebalance the risk-reward calculus between Company shareholders and ratepayers (Attorney General Brief at 16).

2. DOER

DOER maintains that the Company's proposed metrics are simply tracking metrics (DOER Reply Brief at 14-15). Specifically, DOER contends that the proposed metrics track the Company's own emissions, not those of its customers (DOER Reply Brief at 14-15). In addition,

GSEP within five years shall be repaired or eliminated within three years of initial designation; and (ii) leak-extent designated leaks with a leak extent greater than 10,000 square feet shall be repaired or eliminated within twelve months of initial designation, provided that any such leaks located on a pipe scheduled for repair under the GSEP within three years shall be repaired or eliminated within two years of initial designation. 220 CMR 114.07.

DOER asserts that the Company's proposed emissions metrics track progress on projects related to the GSEP, which are already required by statute (DOER Reply Brief at 14-15).

DOER also contends that the Company's proposed emissions scorecard metrics do not amount to new or incremental commitments to reduce its customers' reliance on natural gas (DOER Reply Brief at 14-15). DOER asserts that to rectify these deficiencies, the Department should direct Unitil to complete the strategic electrification case study on York Avenue in Fitchburg and to file a report with the results in a compliance filing in this docket no later than January 31, 2025, or another date prior to the Company's submission of its first Climate Compliance Plan on April 1, 2025, pursuant to the directives in Investigation into Role of Gas Local Distribution Companies as Commonwealth Achieves Target 2050 Climate Goals, D.P.U. 20-80-B (2023) (DOER Brief at 27-29; DOER Reply Brief at 15). According to DOER, the urgency of the Commonwealth's statutory emissions reduction targets for 2025 and 2030 requires that pilot proposals be as far along as possible prior to utilities making compliance filings required by the Department's decision in D.P.U. 20-80-B (DOER Brief at 28-29; DOER Reply Brief at 15).

3. Company

Unitil asserts that it has provided detailed information on its proposed metrics, sufficient to provide the Department and stakeholders with a means to track how the Company is managing its operations in light of the shifts facing the electric and gas industries (Company Brief at 138 (electric), citing Exh. DPU 38-1 (electric); Company Brief at 117 (gas), citing

Exhs. Unitil-DJH-1, at 15-16, 24-25 (gas); Unitil-GSMP-1, at 6 (gas)).[29] The Company also contends that it has provided substantial evidence that its proposed metrics fully comply with Department precedent, and that all the proposed metrics are based on metrics that have been approved by the Department for use in the context of PBR plans (Company Brief at 139 (electric), citing Exh. Unitil-ESMP-Rebuttal at 22 (electric); Company Brief at 117-118 (gas), citing Exh. Unitil-GSMP-Rebuttal at 22 (gas)). Further, Unitil rejects the Attorney General's contention that the Company's proposed metrics are not linked to PBR outcomes and argues that its proposed metrics are tied to the goals of the PBR plans because a primary goal of the plans is to establish a framework that provides the necessary revenue support, without multiple time-consuming rate cases, to enable the Company to focus on activities that advance state policy (Company Brief at 139 (electric); Company Brief at 118-119 (gas)). According to Unitil, the proposed metrics will track the Company's performance on these activities (Company Brief at 139 (electric); Company Brief at 118-119 (gas)).

Regarding specific metrics, Unitil argues the Department has found there is value in including customer satisfaction metrics as part of a PBR plan evaluation and, as such, the Company proposes the various scorecard metrics focused on customer satisfaction and engagement (Company Brief at 128-132 & n.52 (electric), citing D.P.U. 19-120, at 110). In particular, Unitil asserts that nearly all of these metrics are directly related to digital engagement

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29 The Company concedes that for some proposed metrics, final targets and annual reporting requirements will be set in the context of a future annual PBR adjustment filing as more information becomes available (Company Brief at 124-125 (electric), citing Exhs. Unitil-ESMP-1, at 14-15 (Rev.) (electric); DOER 2-14 (Rev.) (electric); Company Brief at 111 (gas), citing Exh. Unitil-GSMP-1, at 24 (gas)).

with customers and are intended to bring the Company into closer alignment with the expectations of its customers, streamline digital communication options, and modernize the customer experience through technological innovation (Company Brief at 128 (electric)).

The Company also contends that its proposed metric to track termination of electric service to low-income customers is both consistent with the approved metric in D.P.U. 22-22 and is timely given the Department's recently opened investigation into energy affordability for residential customers in Energy Burden Inquiry, D.P.U. 24-15 (Company Brief at 126 (electric), citing Exh. Unitil-ESMP-Rebuttal at 16-18 (electric)). Further, the Company asserts that in several PBR proceedings, the Department has identified system peak demand reduction as an important objective, thus justifying the four proposed peak demand metrics (Company Brief at 132-135 & n.56 (electric), citing D.P.U. 22-22, at 121-122; D.P.U. 17-05, at 407, 409-410). Likewise, for the gas division, the Company stresses that measuring performance in the areas of safety and reliability are key components of a PBR plan and, as such, warrant the proposed safety and reliability metrics (Company Brief at 102-107 (gas)).

Similarly, the Company notes that the Department has previously recognized that metrics measuring progress towards climate transition and GHG emissions reductions are an appropriate component of a PBR plan (Company Brief at 135 (electric); Company Brief at 117 (gas)). The Company contends that its proposed metric is in line with its enterprise-wide carbon targets (Company Brief at 135 (electric), citing Exh. DPU 20-1 (electric); Company Brief at 115, citing Exhs. Unitil-GSMP-1, at 31 (gas); DPU 25-6 (gas)). Unitil also claims that the Department has found that a methane emissions reduction metric tied to the GSEP will assure the Company is achieving the emission target goals while facing future uncertainties in the gas distribution industry (Company Brief at 114 (gas), citing D.P.U. 20-120, at 141; D.P.U. 19-120, at 111). Moreover, the Company reiterates its commitment to repair G3SEI leaks, and notes that if there are changes to the GSEP statute during the PBR term, the Company will revise the G3SEI metric as necessary (Company Brief at 113 (gas), citing Exh. Unitil-GSMP-1, at 8, 28, 31 (gas)).

The Company explains that it did not propose incentives or penalties to its proposed metrics because it maintains that in the initial stages (i.e., first generation) of PBR implementation, "reporting-only" scorecard metrics are more appropriate in identifying the data and information needed, the quality and volume of data generated, as well as how it should be measured, tracked, and reported (Company Brief at 127 (electric), citing D.P.U. 20-120, at 3, 130-141; D.P.U. 19-120, at 106-113; D.P.U. 18-150, at 120-132). Furthermore, according to the Company, several of the metrics relate to processes that are still being developed and, as such, it is too soon to construct reasonable penalties or metric-specific incentives (Company Brief at 127 (electric), citing Exhs. Unitil-ESMP-1 (Rev.) at 14-15, 18-19 (electric); DPU 28-6 (electric); DPU 28-8 (electric); DPU 28-9 (electric); DPU 28-10 (electric); Company Brief at 119 (gas), citing Exhs. Unitil-GSMP-1, at 24, 27-28 (gas); DPU 23-3 (gas); DPU 23-6 (gas)).

Unitil disagrees with the Attorney General's assertion that because the proposed metrics do not include penalties, they do not commit the Company to achieving the Commonwealth's policy objectives, and that penalties are necessary to rebalance the risk-reward calculus between Company shareholders and ratepayers[30] (Company Brief at 139 (electric), citing Attorney

30 Unitil argues that its proposed ESM, under which customers share in earnings surpluses above a threshold but are not responsible for earnings deficits at any level, directly contradicts the Attorney General's assertion that the risk-reward calculus in the

General Brief at 16; Company Brief at 119 (gas)). Unitil argues that an asymmetrical penalty-only framework would shift the focus of the PBR from improving existing processes and services and advancing Commonwealth policy objectives to maintaining the level of performance necessary to avoid penalties (Company Brief at 140 (electric), citing Exh. DPU 13-12; Company Brief at 119 (gas), citing Exhs. Unitil-GSMP-Rebuttal at 7 (gas); DPU 11-8 (gas)). Nonetheless, the Company asserts that it will identify and develop a symmetrical (incentive/penalty) framework by the fourth year of the PBR plans (Company Brief at 142 (electric), citing Exh. Unitil-ESMP-Rebuttal at 10 (electric); Company Brief at 121 (gas), citing Exh. Unitil-GSMP-Rebuttal at 6)). Unitil maintains that collecting data for a minimum of three years to develop a symmetrical penalty/incentive mechanism is consistent with the Department's service quality precedent (Company Brief at 142 (electric), citing Exh. Unitil-ESMP-Rebuttal at 10 (electric), citing Service Quality Guidelines, D.P.U. 12-120-D at 45, 46 n.7, 57 (2015); D.P.U. 12-120-C at 81, 100; Company Brief at 121 (gas)).

Regarding DOER's arguments, Unitil argues that DOER fails to recognize the steps the Company has taken to continue to advance the Commonwealth's energy transition, as embedding sustainability into the Company's strategic decision-making process and lowering GHG emissions are central to its vision and operating philosophy (Company Brief at 100 (gas), citing Exh. Unitil-GSMP-1, at 28 (gas)). The Company notes that these objectives are key

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Company's PBR plans is tilted in favor of investors (Company Brief at 140 (electric), citing Exhs. Unitil-RBH-1, at 28-29 (electric); DPU 41-4 (electric); Company Brief at 120 (gas), citing Exhs. Unitil-DJH-1, at 22-23 (gas); Unitil-GSMP-Rebuttal at 8 (gas); DPU 32-2 (gas)).

components of the proposed PBR plans in the form of relevant scorecard metrics (Company Brief at 100 (gas), citing Exh. Unitil-GSMP-1, at 28-34 (gas)).

Further, the Company notes that the objective of the York Avenue electrification study is to identify the estimated scope, schedule, costs, challenges, benefits, and rate impacts of neighborhood electrification of the gas distribution system (Company Brief at 100-101 (gas), citing Exhs. Unitil-DJH-Rebuttal at 26 (gas); DOER 3-1). According to the Company, the overall goal of the study is to determine the costs and benefits of neighborhood electrification in advance of filing a neighborhood electrification pilot as part of the Company's Climate Compliance Plan as set out in D.P.U. 20-80-B (Company Brief at 101 (gas), citing Exh. DOER 3-1). Unitil asserts that DOER has failed to provide any justification to "artificially accelerate" the Company's timeline for carefully and deliberately investigating and analyzing a complex issue (Company Brief at 101 (gas)).

D. Analysis and Findings

1. Introduction

As discussed in Section III.D.4. above, the Department has approved separate PBR plans for the Company's electric and gas divisions. To measure the full range of benefits that will accrue under the PBR plans, the Department finds that it is appropriate to establish a set of broad performance metrics that are tied to the goals of the PBR plans and are consistent with the Department's regulatory objectives.

The Attorney General and DOER raise concerns that as tracking metrics, the metrics produce insufficient information and will not incentivize customer benefits (Attorney General Brief at 16; DOER Reply Brief at 14-15). The Attorney General also raises concerns regarding the lack of penalties for substandard performance and asserts that the metrics should include financial penalties to rebalance the risk-reward calculus between Company shareholders and ratepayers (Attorney General Brief at 16). The Department is unpersuaded by these concerns. Although the metrics are tracking and reporting in nature, the Company still is subject to penalties for deficient performance under the Department's service quality guidelines. Further, the approved PBR plans should incentivize the Company to reduce costs and operate more efficiently.

The Department has reviewed the extensive record regarding the Company's proposed metrics (see, e.g., Exhs. Unitil-ESMP-1, at 9-31 (Rev.) (electric); Unitil-ESMP-Rebuttal at 3-30 (electric); AG-DED-1, at 46-65; DOER-1, at 34-35; AG 7-32 (electric); DOER 2-13 through DOER 2-15 (electric); DPU 20-1 through DPU 20-13 (electric); DPU 32-1 through DPU 32-8 (electric); DPU 38-1 through DPU 38-13 (electric); DPU 52-2 through DPU 52-9 (electric); Unitil-GSMP-1, at 10-33 (gas); Unitil-GSMP-Rebuttal at 3-29 (gas); AG 7-38 (gas); DOER 2-13 through DOER 2-15; DPU 6-10 (gas); DPU 23-2 through DPU 23-6 (gas); DPU 25-2 though DPU 25-8 (gas); DPU 27-1 through DPU 27-9 (gas); DPU 43-7 (gas)); Tr. 6, at 544-564). As discussed further below, we find that each of the proposed metrics is tied to the goals of the PBR plan and is consistent with the Department's regulatory objectives, subject to the modifications below.

2. Proposed Metrics

a. Customer Satisfaction and Engagement Metrics (Electric and Gas Divisions)

i. Customer Satisfaction with Customer Service Metric (Electric and Gas Divisions)

As noted above, Unitil's proposed customer satisfaction with customer service metric is based on a survey conducted by the Company's cloud-based phone system and applies to electric and gas customers (Exhs. Unitil-ESMP-1, at 12-13 (Rev.) (electric); DPU 52-2 (electric); Unitil-GSMP-1, at 21-22 (gas); DPU 40-1 (gas)). The Department has previously expressed a preference for relative rankings and third-party survey administration for PBR metrics, most recently for NSTAR Electric. D.P.U. 22-22, at 116. The Department, however, recognizes Unitil's limited resources and the potential expense associated with retaining outside survey administrators, and we find that the Company should move forward with its numerical score and self-administration of its satisfaction survey (Exhs. Unitil-ESMP-Rebuttal at 15, 20 (electric); Unitil-GSMP-Rebuttal at 15, 20-21 (gas)). The Company proposes a target of 85 percent of calls scoring high enough to qualify as "satisfied," which is a four-point reduction from its current three-year average of 89 percent of callers qualifying as "satisfied" (Exhs. Unitil-ESMP-1, at 12 (Rev.) (electric); Unitil-GSMP-1, at 22 (gas)). The Department finds that a target that represents a decrease from current performance does not put an appropriate emphasis on customer service, nor does it represent the preservation of an already-high level of customer service. Accordingly, the Department directs the Company to change its customer satisfaction with customer service target to preserve the current customer satisfaction service level of at least 89 percent over the five-year term of the PBR plan.

Further, the Company proposes to alter the customer satisfaction ranking scale from a range of one to seven where the percentage of responses with a rating of five to seven is categorized as "satisfied," to a range of zero to ten where the percentage of responses with a rating of six to ten is categorized as "satisfied" (Exhs. Unitil-ESMP-1, at 12 (Rev.) (electric); DPU 32-5 (electric); Unitil-GSMP-1, at 22 (gas); DPU 27-3 (gas)). The Department is not persuaded that a widening of the range of customer responses that qualify as "satisfied" is appropriate. To properly measure customer satisfaction, and in conjunction with maintaining the customer satisfaction service level of at least 89 percent, we direct the Company to consider only ratings between seven and ten (on a scale of zero to ten) as "satisfied." Further, we direct Unitil to develop options for customers who speak languages other than English and limited English proficient speakers to respond to the survey, and to report on these efforts in the first annual PBR adjustment filing.[31] With these modifications, the Department finds that the customer satisfaction with customer service metric appropriately creates a focus on customer service (Exhs. Unitil-ESMP-1, at 12 (Rev.) (electric); DPU 32-5 (electric); DPU 52-3, Att. 1 (electric); Unitil-GSMP-1, at 21-22 (gas); DPU 27-3 (gas); DPU 40-2, Att. 1 (gas)).

ii. Digital Engagement Metrics (Electric and Gas Divisions)

The Company proposes several metrics in the area of digital engagement: (1) MyUnitil Profiles; (2) self-service transactions; (3) customer notification and alerts; (4) mobile

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31 In selecting the non-English languages, the Company shall be guided by the Massachusetts Office of Environmental Justice and Equity "languages spoken" map, which can be found at the following website: https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts. The Company shall select the languages spoken by more than five percent of the population in the service area.

applications; and (5) outage notifications (Exhs. Unitil-ESMP-1, at 9, 13-19 (Rev.) (electric); Unitil-GSMP-1, at 8, 22-28 (gas)). The Department recognizes that customers rely on digital interactions to pay bills, report outages, receive service updates, etc. As such, there are benefits to providing convenient and accessible digital tools to customers and doing so can improve customer experience and education. It stands to reason that the Company's suite of digital engagement metrics is an important component in this process.

Unitil has not proposed any performance targets for its digital engagement metrics, but the Company intends to do so once Project Phoenix is completed and functionality enabled (Exhs. Unitil-ESMP-1, at 14-19 (Rev.) (electric); Unitil-GSMP-1, at 25-27 (gas)). The Department has found that a lack of historical data is not necessarily a reason to reject proposed metrics, especially if additional reporting over time will ameliorate any concerns and allow the Department to assess improvements. D.P.U. 19-120, at 110. The Department, however, finds that a proposed metric at least should be developed to some degree before it is presented for our evaluation. Based on these considerations, the Department approves the Company's MyUnitil profiles and self-service transactions metrics, and we direct the Company to provide baselines and goals for these metrics as part of its 2025 annual PBR adjustment filings (Exhs. Unitil-ESMP-1, at 16-17 (Rev.) (electric); DPU 28-9 (electric); Unitil-GSMP-1, at 25-26 (gas); DPU 23-6 (gas)).

The remaining three digital engagement metrics – notification and alerts, mobile applications, and outage notifications – are broad categories, and the Company has not described the metrics to any degree of specificity, as it still is working with vendors to develop the metrics (Exhs. Unitil-ESMP-1, at 18-19 (Rev.) (electric); Unitil-GSMP-1, at 27-28 (gas)). Accordingly, the Department finds it is premature to approve these three metrics. The Department directs the Company to develop the metrics and their baselines and targets and to present complete proposals as part of the 2025 annual PBR adjustment filings (Exhs. DPU 28-9 (electric); DPU 23-6 (gas)). The Department will evaluate the appropriateness of the Company's digital engagement metric proposals at that time.

iii. Average Speed of Answer of Gas Emergency Calls Metric (Gas Division)

Finally, Unitil proposed a metric to measure its call response time to gas leak, odor, and emergency calls for its gas division (Exh. Unitil-GSMP-1, at 20 (gas)). The metric measures the amount of time, in seconds, for a customer service representative to answer a customer emergency call (Exh. Unitil-GSMP-1, at 20 (gas)). Unitil's current three-year average is slightly over four seconds, but the Company proposes to maintain an average of ten seconds or better over the PBR term (Exh. Unitil-GSMP-1, at 20 (gas)). The Department finds that a target that represents a significant decrease from current performance does not sustain the Company's level of performance. Accordingly, the Department directs Unitil to change its Gas Emergency Calls – Average Speed of Answer metric target in its annual PBR adjustment filings to five seconds to preserve a similar level of performance over the PBR plan term.

iv. Low-Income Service Termination Metric (Electric Division)

Next, Unitil proposed a metric to track termination of service to low-income electric customers (Exh. Unitil-ESMP-Rebuttal at 18 (electric)). The Department finds that the proposed low-income termination metric is reasonable and reflects important policy goals

(Exh. Unitil-ESMP-Rebuttal at 17 (electric)). Accordingly, the Department approves the low-income termination metric.

b. Peak Demand Reductions Metrics (Electric Division)

As noted above, the Company proposed a total of four metrics in the category of peak demand reduction: (1) a measure of the battery output at the Townsend substation; (2) a measure of the impact of VVO technology on peak load reduction; (3) a measure of the peak demand reduction from the energy efficiency programs; and (4) a measure of the peak demand reduction from ADR (Exh. Unitil-ESMP-1, at 9, 20-27 (Rev.) (electric)). In D.P.U. 17-05, at 409-410, the Department identified system peak demand reduction as an important objective and found that the Company should consider all aspects of its business to set a comprehensive target and identify a separate benchmark to allow for the portion of the target that is enabled by PBR. In D.P.U. 22-22, at 121-122, the Department determined that the proposed peak demand reduction metrics were an appropriate starting point for developing a more advanced system peak reduction metric, and that reporting on the proposed peak demand reduction metric would provide important data to facilitate the evaluation of benefits associated with the Company's demand reduction efforts. D.P.U. 22-22, at 121-122.[32]

As proposed by the Company, the Department finds that the Company's proposed peak demand reduction metrics do not measure how the proposed PBR plan directly impacts the

[32] NSTAR Electric, similar to Unitil, proposed a peak reduction metric which separately measured and reported peak reductions stemming from six measures and programs: (1) energy efficiency; (2) demand response; (3) company-owned storage; (4) company-owned solar; (5) upgrades to standard technologies; and (6) VVO. D.P.U. 22-22, at 91.

demand reduction results (Exhs. Unitil-ESMP-1, at 9, 20-27 (Rev.) (electric); DPU 20-1 (electric); DPU 20-2 (electric)). Further, the targets for these metrics were established outside of the context of the PBR plan, as the Townsend substation project is currently in service and is set to discharge in a manner that reduces peak transformer load by the target amount. The VVO target reductions are based on assumptions reported in the Company's 2022-2025 Grid Modernization Plans, and the energy efficiency and ADR targets are based on and extrapolated from the Company's current energy efficiency plan (Exhs. Unitil-ESMP-1, at 21-26 (Rev.) (electric); DPU 20-1 (electric)). Further, most of the capital costs associated with achieving these targets are recovered through non-PBR avenues, as VVO investments are recovered through the Grid Modernization Factor ("GMF") while energy efficiency and ADR program costs are recovered through the Company's energy efficiency charge (Exh. DPU 20-2 (electric)). Moreover, the Company does not contend that the targets for the four metrics would not be achieved in absence of the PBR plan (Exh. DPU 20-2 (electric)).

The Department recognizes that under the PBR plan, Unitil will be working to manage costs and operations across all of the Company's assets (Exh. DPU 38-10 (electric)). As such, reporting on the proposed metrics could provide important insights into how the Company is working to advance the Commonwealth's policies. Further, Unitil expects that the PBR plan will produce peak load reductions above and beyond what could be achieved under the Company's current regulatory framework (Tr. 6, at 548-549). Additionally, the Company expects that the PBR framework will allow it to manage its costs and operations associated with all its assets to advance the Commonwealth's policies in a more efficient manner (Tr. 6, at 553-554). The Department expects that this increased efficiency should result in improved performance across the associated peak reduction programs. Furthermore, additional reductions could result from the Company leveraging the PBR mechanism to identify and implement additional types of measures that may reduce peak load (Tr. 6, at 549-551).

The Department also expects reductions of peak demand under a PBR plan to exceed the aggregate of reductions forecasted from non-PBR mechanisms, due to the efficiency gains and additional measures discussed above. The proposed peak demand reduction metrics are a starting point for developing a more advanced system peak reduction metric. As such, the Department approves the Company's proposed peak reduction metrics, with the following modifications and additions. First, we direct the Company to report its Company-owned storage metric as a non-asset specific metric, which would allow any future asset contributions to be included and not just limited to the Townsend substation project. Next, the Department directs the Company to include an additional "other" category to track PBR-enabled reductions from yet to be identified and implemented initiatives. Finally, the Department directs the Company to report the aggregate reductions from all tracked categories. As the Department expects the proposed PBR plan to generate peak reduction benefits beyond what is achieved under the Company's current regulatory framework, comparing the actual aggregate reductions to the sum of the targets will provide insight into this performance.

c. Safety and Reliability Metrics (Gas Division)

As described above, Unitil proposed four metrics under the safety and reliability category: (1) emergency response rate within 45 minutes; (2) total damages per 1,000 Dig Safe tickets; (3) total grade 2 leaks older than nine months; and (4) PSMS implementation (Exh. Unitil-GSMP-1, at 7, 10-19 (gas)). First, for the emergency response rate metric, the

Company set a performance target of 95 percent of calls responded to within 45 minutes (Exh. Unitil-GSMP-1, at 11 (gas)). The Company's five-year response rate is 99 percent of calls within 45 minutes (Exh. Unitil-GSMP-1, at 11 (gas)). Although the Company's proposed target is slightly below the average, the Department finds that the proposed target will still maintain a high level of performance over the five-year PBR term. Further, the proposed target compares favorably with the current service quality standard of 97 percent of Class I and Class II odor calls within 60 minutes. Service Quality Investigation, D.P.U. 16-80 through D.P.U. 16-90, Att. A at 14 (2017). Accordingly, the Department approves the Company's metric.

Second, the Department finds that Unitil's total damages per 1,000 Dig Safe tickets metric appropriately creates a focus on risk mitigation and safety, is important for tracking the effectiveness of the Company's damage prevention program, and is consistent with Department precedent. D.P.U. 20-120, at 138-139; D.P.U. 19-120, at 108. The Department, however, directs the Company in its annual PBR adjustment filings to expand the damage prevention metric to include the following additional measures: (1) cost of at-fault damages (Company at fault); (2) cost of not-at-fault damages (third-party contractor); and (3) costs recovered for not-at-fault damages (third-party contractor). These additional measures will provide the Department with more insight and information with which to evaluate the Company's progress in safety over the course of the PBR term. These measures will also allow the Department to assess the impacts of damages that are the Company's fault, versus those that are not. Further, the Department directs the Company to provide in its annual PBR adjustment filings the most recent three years of data of the aforementioned additional measures, if available, to establish an appropriate benchmark. The Department also finds that the Company's proposed baseline and target measure of

1.95 damages per 1,000 Dig Safe tickets is reasonable (Exh. Unitil-GSMP-1, at 13 (gas)). Accordingly, the Department approves this metric with the foregoing modifications.

Third, the Company proposed to repair or eliminate all Grade 2 leaks within nine months of detection (Exh. Unitil-GSMP-1, at 15-16 (gas)). It is a statutory requirement that Grade 2 leaks must be repaired within twelve months from the date of classification. G.L. c. 164, § 144. The Department has found that with respect to emissions reductions, any improvement from the statutory requirements is a noteworthy goal that benefits customers and the environment. D.P.U. 19-120, at 112. Accordingly, the Department approves the Company's metric, as it reflects a commitment to maintaining an aggressive approach toward the elimination of gas leaks.

Finally, with respect to PSMS implementation, the Company proposes a target of achieving the "implemented" stage by the end of the PBR term, and to engage a third party in 2024 to perform an independent assessment of the Company's PSMS implementation and to set a baseline for this metric (Exhs. Unitil-GSMP-1, at 19 (gas); DPU 23-5 (gas)). The Department finds that the Company's proposal is consistent with precedent and the commitment to pipeline safety efforts will result in improvements in safety and reliability, which benefit customers. D.P.U. 20-120, at 139; D.P.U. 19-120, at 108-109. Accordingly, the Department approves this metric.

d. <u>Climate Transition and GHG Emissions Reduction Metric (Electric and Gas Divisions)</u>

As noted above, the Company proposes a climate transition metric that will target a ten-percent reduction in Scope 1 emissions by 2027, against a 2022 baseline (Exhs. Unitil-ESMP-1, at 30 (Rev.) (electric); DPU 20-4 (electric); Unitil-GSMP-1, at 32 (gas);

DPU 6-10 (gas); DPU 25-6 (gas)). The proposed metric will report the Company's progress towards meeting the target on a Massachusetts-specific basis (Exhs. Unitil-ESMP-1, at 30-31 (Rev.) (electric); DPU 20-4 (electric); Unitil-GSMP-1, at 33 (gas); DPU 25-6 (gas)).

The Department recognizes that GHG emissions reductions are broad-ranging initiatives, and that the Company's proposed metric provides a means to track how it is managing its operations working to advance critical policy initiatives (Exhs. Unitil-ESMP-1, at 28 (Rev.) (electric); DPU 38-1 (electric); Unitil-GSMP-1, at 33 (gas)). Additionally, the Department has recognized that metrics measuring progress towards climate adaptation and GHG emissions reductions are reasonable and appropriate in connection with a PBR plan. D.P.U. 22-22, at 122-123; D.P.U. 20-120, at 141; D.P.U. 19-120, at 111-112; D.P.U. 17-05, at 411. As such, the Department approves the Company's climate transition and GHG emissions reduction metric, with one modification. We direct the Company to report its emissions reductions on a Massachusetts-only basis relative to a 2022 baseline, as proposed, and to include segment reporting by source type. Specifically, the Company shall break out its proposed reported Scope 1 emissions into GHG Protocol Standard categories and shall include the Scope 2 category of emissions due to consumption of purchased electricity and electric transmission and distribution line losses. This directive is intended to provide additional insight into the Company's actions to further key policy goals. Finally, we note that Unitil is developing a climate adaptation/transition plan to achieve its stated objectives with respect to reducing GHG emissions (Exhs. Unitil-ESMP-1, at 29 (Rev.) (electric); DPU 20-3 (electric); Unitil-GSMP-1, at 31-32 (gas)). The Department directs Unitil to include in its annual PBR adjustment filings an update to the completion status of its climate adaptation/transition plan and to submit a copy of the plan when it is completed.

e. Emissions Reduction Metrics (Gas Division)

The Company proposes a metric that will measure progress in emissions reductions, in metric tons, associated with replacement of leak-prone distribution infrastructure through the GSEP (Exh. Unitil-GSMP-1, at 8, 30 (gas)). Specifically, the Company targets a 50 percent reduction by 2027 to its 2018 year-end baseline of 2,075 metric tons of methane emissions (Exhs. Unitil-GSMP-1, at 30; DPU 25-2 & Atts. (gas)). As an initial matter, we find that the Company's baseline is appropriate, as it represents the first year of reporting pursuant to 310 CMR 7.73 (Exhs. Unitil-GSMP-1, at 29 (gas); DPU 25-2 & Atts. (gas)). Further, the Department finds that this metric can serve as an indicator of the Company's ability to properly manage the GSEP program among all other necessary work to provide safe and reliable natural gas service, and to continuously achieve the annually declining emissions limits per MassDEP's regulations. Additionally, the metric would provide assurance that the Company is managing its GSEP program in light of the future uncertainties in the gas distribution industry. We also find that the metric is consistent with those previously approved by the Department. D.P.U. 20-120, at 141; D.P.U. 19-120, at 111. Accordingly, the Department approves this metric.

Unitil proposed a second emissions reductions metric that will measure the time it takes the Company to repair G3SEI leaks (Exh. Unitil-GSMP-1, at 8, 28 (gas)). Emissions reductions are important from an environmental policy perspective, and timely G3SEI leak repairs can improve public safety and reduce the risk of long-term environmental impact. The Company's metric will commit it to repairing all G3SEI leaks located on non-GSEP infrastructure within twelve months of designation, which exceeds the requirement in the Department's regulations (Exh. Unitil-GSMP-1, at 8, 28, 30-31 (gas)). 220 CMR 114.07. Accordingly, we approve this metric.

Finally, we address DOER's arguments regarding customer emissions and reliance on natural gas and the York Avenue electrification study (DOER Brief at 27-29; DOER Reply Brief at 14-15). In D.P.U. 20-80-B at 87, the Department directed each LDC to work with the relevant EDC to study the feasibility of piloting a targeted electrification project in its service territory. The Department directed each LDC to file its project proposal by March 1, 2026, for inclusion in its 2030 Climate Compliance Plan. D.P.U. 20-80-B. The Company reports that it is in the early stages of developing the York Avenue neighborhood electrification case study (Exhs. Unitil-RBH-Rebuttal at 33 (electric); Unitil-DJH-Rebuttal at 26 (gas); DOER 3-1). The objective is to identify the estimated scope, schedule, costs, challenges, benefits, and rate effects of electrifying the York Avenue gas distribution system located in Fitchburg, which is scheduled to be part of the GSEP in 2030 (Exhs. Unitil-RBH-Rebuttal at 33 (electric); Unitil-DJH-Rebuttal at 26 (gas); DOER 3-1). Further, the Company intends to determine the likely costs and benefits of neighborhood electrification prior to filing a neighborhood electrification pilot by March 1, 2026, as required by D.P.U. 20-80-B (Exhs. Unitil-RBH-Rebuttal at 33 (electric); Unitil-DJH-Rebuttal at 26 (gas); DOER 3-1).

As noted above, DOER asserts that the Department should direct Unitil to complete the strategic electrification case study on York Avenue in Fitchburg and file a report with the results in a compliance filing in this docket no later than January 31, 2025, or another date prior to the Company's submission of its first individual Climate Compliance Plan on April 1, 2025 (DOER

Brief at 27-29; DOER Reply Brief at 15).[33] We are not persuaded that accelerating the York Avenue study is necessary for approval of the PBR plan or scorecard metrics. Nor do we find it appropriate to treat Unitil differently than other LDCs subject to the same directives in our decision in D.P.U. 20-80-B. Given the directives in D.P.U. 20-80-B, and in recognition of the scope of work necessary to complete the electrification study, we decline to modify the March 1, 2026, deadline established in that proceeding at this time.

V. RATE BASE

A. Introduction

Unitil reported a pro forma total utility plant in service balance of $189,114,975 for its electric division (Exh. Sch. RevReq-4 (Rev. 4) (electric)). The Company reduced its total plant in service by $89,728,816 in accumulated depreciation, resulting in a net utility plant in service of $99,386,159 (Exh. Sch. RevReq-4 (Rev. 4) (electric)). Unitil further reduced its net utility plant in service by the following amounts: (1) $11,650,499 in net deferred income taxes; (2) $4,269,516 in excess deferred income taxes; (3) $1,548,062 for customer advances; (4) $168,431 for customer deposits; and (5) $7,597 for unclaimed funds (Exh. Sch. RevReq-4 (Rev. 4) (electric)). Finally, the Company added $2,121,478 in materials and supplies and $1,043,035 in cash working capital (Exh. Sch. RevReq-4 (Rev. 4) (electric)). Based on these

33 In D.P.U. 20-80-B at 134, the Department directed each LDC to file individual Climate Compliance Plans every five years, with the first such Plan being due on or before April 1, 2025.

adjustments, the Company determined that its total pro forma electric division rate base was $84,906,567 (Exh. Sch. RevReq-4 (Rev. 4) (electric)).[34]

Unitil reported a pro forma total utility plant in service balance of $218,160,275 for its gas division (Exh. Sch. RevReq-4 (Rev. 4) (gas)). The Company reduced its total plant in service by $75,100,925 in accumulated depreciation, resulting in a net utility plant in service of $143,059,350 (Exh. Sch. RevReq-4 (Rev. 4) (gas)). Unitil further reduced its net utility plant in service by the following amounts: (1) $19,268,801 in net deferred income taxes; (2) $5,575,350 in excess deferred income taxes; (3) $21,532 for customer advances; (4) $68,468 for customer deposits; and (5) $7,628 for unclaimed funds (Exh. Sch. RevReq-4 (Rev. 4) (gas)). Finally, the Company added $2,225,875 in materials and supplies and $1,342,689 in cash working capital (Exh. Sch. RevReq-4 (Rev. 4) (gas)). Based on these adjustments, the Company determined that its total pro forma gas division rate base was $121,686,135 (Exh. Sch. RevReq-4 (Rev. 4) (gas)).

B. Plant Additions

1. Introduction

Unitil identified 244 electric division capital projects that were completed between January 1, 2019 and December 31, 2022 (Exh. Sch. Unitil-KSTB-1 (electric)). Moreover, Unitil identified 74 electric division common capital projects that were completed between January 1, 2019 and December 31, 2022 (Exh. Sch. Unitil-KSTB-5 (electric)). Common projects are either: (1) projects allocated across both of the gas and electric divisions of the Company; or (2) USC projects that are allocated across the Company and its affiliates (Exh. Unitil-KSTB-1, at 20 n.2

[34] Minor discrepancies in any of the amounts appearing in this Order are due to rounding.

(electric)). Further, Unitil identified 63 electric division capital projects that were completed between January 1, 2023 and December 31, 2023 (Exh. Sch. Unitil-KSTB-9 (electric)). Finally, Unitil Electric identified 38 electric division common capital projects that were completed between January 1, 2023 and December 31, 2023 (Exh. Sch. Unitil-KSTB-16 (electric)). For each project, the Company provided the funding project number, a brief project description, references to the page numbers of exhibits where construction authorization documentation and cost records can be found for each project, the budgeted amount, the total amount authorized, the plant in service, cost of removal, salvage, and the total amount expended (Exh. Schs. Unitil-KSTB-1 (electric); Unitil-KSTB-5 (electric); Unitil-KSTB-9 (electric); Unitil-KSTB-16 (electric)).

In addition, Unitil proposes to move into rate base capital projects reviewed by the Department in the Company's CCA proceedings for capital additions made since January 1, 2019, including the Townsend Substation Battery Storage Project[35] (Exh. Unitil-KSTB-1, at 23, 24 (electric)). Further, the Company proposes to transfer recovery of the Sawyer Passway Solar Facility[36] into rate base and to flow the market recovery credits associated with the solar investments to customers through the Revenue Decoupling Adjustment Factor ("RDAF") rather

35 The Townsend Substation Battery Storage Project uses the energy stored at the substation in Townsend to reduce load during key hours of the day, which enables the Company to avoid the need for future expensive upgrades at the substation level (Exh. Unitil-KSTB-1, at 25 (electric)). The project was reviewed by the Department in and placed in service in 2021. D.P.U. 22-82-A at 7 & Exh. Unitil-DJH-2, at 1, line 24.

36 This proposal is discussed in Section XIII.D. below.

than continuing to return these credits to customers through the SCA cost recovery factor (Exh. Unitil-CGDN-1, at 7 (electric)).

Unitil identified 135 gas division capital projects that were completed between January 1, 2019 and December 31, 2022 (Exh. Sch. Unitil-KSTBCL-1 (gas)). Unitil identified 74 gas division common capital projects that were completed between January 1, 2019 and December 31, 2022 (Exh. Sch. Unitil-KSTBCL-5 (gas)). Common projects are either: (1) projects allocated across both of the gas and electric divisions of the Company; or (2) USC projects that are allocated across the Company and its affiliates (Exh. Unitil-KSTBCL-1, at 21 n.3 (gas)). In addition, Unitil identified 39 gas division capital projects that were completed between January 1, 2023 and December 31, 2023 (Exh. Sch. Unitil-KSTBCL-9 (gas)). Finally, Unitil Gas identified 38 gas division common capital projects that were completed between January 1, 2023 and December 31, 2023 (Exh. Sch. Unitil-KSTBCL-16 (gas)). For each project, the Company provided the funding project number, a brief project description, references to the page numbers of exhibits where construction authorization documentation and cost records can be found for each project, the budgeted amount, the total amount authorized, the plant in service, cost of removal, salvage, and the total amount expended (Exh. Schs. Unitil-KSTBCL-1 (gas); Unitil-KSTBCL-5 (gas); Unitil-KSTBCL-9 (gas); Unitil-KSTBCL-16 (gas)).

2. Project Documentation

Unitil's electric division annual capital budgeting process relies on engineering planning studies that identify the need for reliability projects and system improvements (Exhs. Unitil-KSTB-1, at 6 (electric); Unitil-KSTBCL-1, at 7 (gas)). Capital budgets are created using a "bottom up" process with input from dozens of engineering, operations, and IT employees and, upon approval by senior management, the final budget is presented to the Board of Directors for final approval (Exhs. Unitil-KSTB-1, at 6-7 (electric); Unitil-KSTBCL-1, at 7-8 (gas)). Each project[37] submitted must meet the following requirements: (1) a well-defined project scope; (2) a detailed justification that describes the need for the project; and (3) the cost of each project estimated to a level of accuracy of 80 percent or better (Exhs. Unitil-KSTB-1, at 8 (electric); Schs. Unitil-KSTB-14 (electric); Unitil-KSTB-15 (electric); DPU 22-1 (electric); Unitil-KSTBCL-1, at 9 (gas); Schs. Unitil-KSTBCL-14 (gas); Unitil-KSTBCL-15 (gas)). In addition, all projects in the capital budget are also assigned one of three priorities, varying from essential to discretionary (Exhs. Unitil-KSTB-1, at 10 (electric); Sch. Unitil-KSTB-15 (electric); Unitil-KSTBCL-1, at 10-11 (gas); Sch. Unitil-KSTBCL-15 (gas)). The Company reviews each electric and gas division project to ensure that it has been appropriately categorized and prioritized within the budget, and to ensure that complete documentation of scope, justification, and cost estimates have been provided (Exhs. Unitil-KSTB-1, at 10 (electric); Schs. Unitil-KSTB-14; Unitil-KSTB-15 (electric); DPU 22-1 (electric); Unitil-KSTBCL-1, at 11 (gas); Schs. Unitil-KSTBCL-14 (gas); Unitil-KSTBCL-15 (gas)).

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[37] Each project is classified into categories, which include transmission, substation, electric distribution, annual requirements, transportation, structures, and general equipment (Exhs. Unitil-KSTB-1, at 9 (electric); Unitil-KSTBCL-1, at 10 (gas)). Each category is further divided into subcategories such as overhead extensions, underground extensions, street light projects, telephone company requests, line relocations (highway projects), and reliability projects for the electric division and main extensions, pipe replacements, highway projects, distribution system improvements, valve installation and other specific projects for the gas division (Exhs. Unitil-KSTB-1, at 9 (electric); Unitil-KSTBCL-1, at 10 (gas)).

Further, a construction authorization must be prepared and submitted for approval for each project in the budget, and each authorization must be fully approved prior to the commencement of any work, except in unforeseen emergencies (Exhs. Unitil-KSTB-1, at 11-12 (electric); Schs. Unitil-KSTB-14 (electric); Unitil-KSTB-15 (electric); Unitil-KSTBCL-1, at 12-13 (gas); Schs. Unitil-KSTBCL-14 (gas); Unitil-KSTBCL-15 (gas)). Each construction authorization form includes: (1) a project description and objectives; (2) a scope and justification; (3) an estimated cost summary; (4) project schedule; (5) project milestones; (6) management/approver authorization signatures; and (7) changes in scope or spending (Exhs. Schs. Unitil-KSTB-4 (electric); Unitil-KSTB-15 (electric); Schs. Unitil-KSTBCL-4 (gas); Unitil-KSTBCL-15 (gas)).

The construction authorizations are approved by one or more managers or department heads, and all authorizations over $50,000 also require the approval of the vice president of finance and regulatory (Exhs. Unitil-KSTB-1, at 12 (electric); Sch. Unitil-KSTB-14 (electric); DPU 22-2 (electric); Unitil-KSTBCL-1, at 13 (gas); Sch. Unitil-KSTBCL-14 (gas)). In addition, all authorizations exceeding $500,000 must be approved by the Company's controller and the chief financial officer (Exhs. Unitil-KSTB-1, at 12 (electric); Sch. Unitil-KSTB-14 (electric); DPU 22-2 (electric); Unitil-KSTBCL-1, at 13 (gas); Sch. Unitil-KSTBCL-14 (gas)). Changes in scope or cost of projects underway require the submission of revised authorizations by the project supervisor and must be resubmitted for approval in the same manner as the original authorization, with the additional approval of the Company's controller and the chief financial officer (Exhs. Unitil-KSTB-1, at 13 (electric); Schs. Unitil-KSTB-14 (electric); Unitil-KSTB-15 (electric); Unitil-KSTBCL-1, at 14 (gas); Schs. Unitil-KSTBCL-14 (gas); Unitil-KSTBCL-15 (gas)). The project supervisor's responsibility is to manage the cost of each project to the original authorized amount; however, a small number of projects may overrun the original estimate due to conditions in the field, increases in material costs, estimating errors, and/or other factors (Exhs. Unitil-KSTB-1, at 13 (electric); Schs. Unitil-KSTB-14 (electric); Unitil-KSTB-15 (electric); Unitil-KSTBCL-1, at 14 (gas); Schs. Unitil-KSTBCL-14 (gas); Unitil-KSTBCL-15 (gas)). For cost control, if the cost of a project exceeds the authorized amount by 15 percent and $5,000, a supplemental authorization must be submitted that includes a detailed description of the reasons the project exceeded its authorized amount and must be resubmitted for approval (Exhs. Unitil-KSTB-1, at 13 (electric); Sch. Unitil-KSTB-14 (electric); Unitil-KSTBCL-1, at 14 (gas); Sch. Unitil-KSTBCL-14 (gas)).

Small, routine projects performed over the course of the year with costs below a specific threshold are budgeted and authorized under a single authorization known as a blanket authorization (Exhs. Unitil-KSTB-1, at 14 (electric); DPU 22-4 (electric); Unitil-KSTBCL-1, at 15 (gas)). Examples include small line extensions, telephone company requests, new outdoor lighting requests, capital repairs to restore service when damage to the electric system occurs, transformer purchases, meter purchases, and requests for billable work (Exh. Unitil-KSTB-1, at 14-15 (electric); Unitil-KSTBCL-1, at 15-6 (gas)). At the beginning of the year, the Company authorizes spending for blanket authorizations for six months; mid-year, the Company reviews the spending against the budget and revises the authorizations for the remainder of the year (Exhs. Unitil-KSTB-1, at 16 (electric); Sch. Unitil-KSTB-14 (electric); DPU 22-4 (electric); Unitil-KSTBCL-1, at 16-17 (gas); Sch. Unitil-KSTBCL-14 (gas)). Individual authorizations are not required for electric division projects where the estimated cost is less than $30,000 and gas division projects where the estimated cost is less than $40,000, provided that such projects are covered by an approved blanket authorization (Exhs. Unitil-KSTB-1, at 15 (electric); Unitil-KSTBCL-1, at 16 (gas)). Similar to other authorizations, if spending under a particular blanket authorization exceeds or is expected to exceed the original authorized amount by 15 percent and $5,000, the blanket authorization must be revised or supplemented (Exhs. Unitil-KSTB-1, at 15 (electric); Unitil-KSTBCL-1, at 16 (gas)).

For the purposes of providing documentation on capital additions, Unitil presented multiple schedules and documents, including: (1) electric and gas plant in service and completed construction not classified from 2019 through 2022; (2) electric and gas plant in service and completed construction not classified by Federal Energy Regulatory Commission ("FERC") account and year from 2019 through 2022; (3) total spend on electric and gas projects closed each year from 2019 through 2022; (4) electric and gas project authorizations, budget inputs, and cost records from 2019 through 2022; (5) for the electric and gas divisions, common plant in service and completed construction not classified from 2019 through 2022; (6) for the electric and gas divisions, common plant in service and completed construction not classified by FERC account and year from 2019 through 2022; (7) total spend on electric and gas common projects closed each year from 2019 through 2022; and (8) for the electric and gas divisions, common project authorizations, budget inputs, and cost records for 2019 through 2022 (Exhs. Schs. Unitil-KSTB-1 through Unitil-KSTB-8 (electric); Schs. Unitil-KSTBCL-1 through Unitil-KSTBCL-8 (gas)). Moreover, Unitil proposed to include in rate base electric and gas division capital additions for projects placed in service and closed to plant by the end of 2023 (i.e., post-test year) (Exhs. Unitil-KSTB-1, at 27(electric); Unitil-KSTBCL-1, at 24-25 (gas)).

During the proceeding, the Company updated the record with the actual 2023 electric and gas plant additions and supporting documentation in a similar manner as outlined above (Exhs. Schs. Unitil-KSTB-9 through Unitil-KSTB-12 (electric); Unitil-KSTB-16 through Unitil-KSTB-19 (electric); DPU 4-1 & Atts. (electric); Sch. Unitil-KSTBCL-9 through Unitil-KSTBCL-12 (gas); Unitil-KSTBCL-16 through Unitil-KSTBCL-19 (gas); DPU 4-1 & Atts. (gas); DPU 32-1 & Atts. (gas)). To support the costs of the capital additions included in the aforementioned listings, the Company provided copies of capital construction authorization forms, supplemental project authorization forms, capital budget estimates, actual project cost records, authority approvals, variance explanations, and closing reports (Exhs. Schs. Unitil-KSTB-1 through Unitil-KSTB-12 (electric); Unitil-KSTB-14 through Unitil-KSTB-19 (electric); DPU 4-1 & Atts. (electric); Schs. Unitil-KSTBCL-1 through Unitil-KSTBCL-12 (gas); Unitil-KSTBCL-14 through Unitil-KSTBCL-19 (gas); DPU 4-1 & Atts. (gas); DPU 32-1 & Atts. (gas)).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's proposed adjustment to the test-year plant in service balances to reflect plant additions and retirements during 2023 should be denied because inclusion of post-test-year expenses is not appropriate when using a historical test year (Attorney General Brief at 62). The Attorney General points out that when using a historical test year, the Department has allowed utilities to recover post-test-year plant additions in limited circumstances, which she claims are not present in this proceeding, such as when a utility sought to include only a specific capital project or initiative representing a significant investment that had a substantial effect on its rate base (Attorney General Brief at 62, citing D.P.U. 20-120, at 79 n.53). According to the Attorney General, the Company seeks to include virtually all 2023 plant additions in its plant in service costs, and in doing so, the Company ignores the Department's past practices or assumes that its proposed PBR plan will be approved (Attorney General Brief at 63). On this last point, the Attorney General argues that the Company, in support of its proposal to include post-test-year plant in service costs, relies on precedent where other utilities were authorized to operate under PBR plans (Attorney General Brief at 64, citing Exh. AG-LKM-Surrebuttal-1, at 2). The Attorney General points out that unlike those companies, Unitil is not currently authorized to operate under a PBR plan and, therefore, the Department should disallow the proposed post-test-year capital projects (Attorney General Brief at 64).

Further, the Attorney General claims that in evaluating the inclusion of post-test-year rate base costs, the prudency of such costs does not overcome the fact that the Department generally does not recognize post-test-year additions or retirements (Attorney General Brief at 64, citing Massachusetts Electric Company, D.P.U. 92-78, at 5 (1992)). Finally, the Attorney General maintains that Unitil's electric division has an existing capital tracker which provides for recovery of all post-test-year capital additions during the annual review of those costs and, therefore, there is no need to include post-test-year capital additions in this case (Attorney General Brief at 64 n.41). For the above reasons, the Attorney General asserts that 2023 plant additions or retirements should not be included in the Company's rate base (Attorney General Brief at 62-64).

b. Company

Unitil maintains that the project documentation provided in this proceeding suffices to facilitate the Department's review of plant additions put into service since the Company's last base distribution rate case and to demonstrate that its capital expenditures were reasonably and prudently incurred (Company Brief at 281, 288 (electric), citing Exh. Schs. Unitil-KSTB-1 through Unitil-KSTB-8 (electric); Company Brief at 234, 242 (gas) citing Exh. Schs. Unitil-KSTBCL-1 through Unitil-KSTBCL-8 (gas)). In addition, Unitil asserts that it provided a detailed explanation of its planning and capital budgeting processes as well as the authorization and control of capital spending (Company Brief at 281 (electric), citing Exhs. Unitil-KSTB-1, at 4, 6-11, 11-18 (electric); DPU 4-1 (electric); Company Brief at 234 (gas), citing Exh. Unitil-KSTBCL-1, at 5, 7-12, 12-19 (gas)). Therefore, the Company maintains that it has demonstrated that its capital additions were prudently incurred and used and useful in providing service to customers and that the Department should approve the capital additions for inclusion in rate base (Company Brief at 281, 288 (electric); Company Brief at 234, 242 (gas)).

Further, Unitil argues that consistent with the Department's decision in D.P.U. 22-22, it is proposing to include in its rate base capital additions for projects placed in service and closed to plant by the end of 2023 (Company Brief at 289 (electric), citing Exh. Unitil-KSTB-1, at 27 (electric); Company Brief at 243-244 (gas), citing Exh. Unitil-KSTBCL-1, at 24 (gas)). The Company submits that during the proceeding, it provided the requisite capital project documentation through the end of calendar year 2023 to support these post-test-year plant additions (Company Brief at 289 (electric), citing Exh. Unitil-KSTB-1, at 28 (electric)).

4. Standard of Review

For costs to be included in rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful to ratepayers. Western Massachusetts Electric Company, D.P.U. 85-270, at 20 (1986). The prudence test determines whether cost recovery is allowed at all, while the used and useful analysis determines the portion of prudently incurred costs on which the utility is entitled to earn a return. D.P.U. 85-270, at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known, or reasonably should have been known, at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (1993); D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. Massachusetts-American Water Company, D.P.U. 95-118, at 39-40 (1996); D.P.U. 93-60, at 35; Fitchburg Gas and Electric Light Company, D.P.U. 84-145-A at 26 (1985).

The Department has cautioned utility companies that, as they bear the burden of demonstrating the propriety of additions to rate base, failure to provide clear and cohesive reviewable evidence on rate base additions increases the risk to the utility that the Department will disallow these expenditures. Massachusetts Electric Company, D.P.U. 95-40, at 7 (1995); D.P.U. 93-60, at 26; The Berkshire Gas Company, D.P.U. 92-210, at 24 (1993); Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967). In addition, the Department has stated that:

> In reviewing the investments …that were made without a cost benefit analysis, the [c]ompany has the burden of demonstrating the prudence of each investment proposed for inclusion in rate base. The Department cannot rely on the unsupported testimony that each project was beneficial at the time the decision was made. The [c]ompany must provide reviewable documentation for investments it seeks to include in rate base.

D.P.U. 92-210, at 24.

5. Analysis and Findings

The Company has provided sufficient project documentation (e.g., capital construction authorization documents, revised or supplemental project authorizations, capital budget estimates, work orders, actual project cost records, the approval routing process, variance explanations, and closing reports) and additional supporting information to enable the Department to determine that the costs associated with its electric division and gas division capital projects through 2023 are known and measurable, prudently incurred, and the capital additions are used and useful in providing service to customers (Exhs. Schs. Unitil-KSTB-1 through Unitil-KSTB-12 (electric); Unitil-KSTB-14 through Unitil-KSTB-19 (electric); DPU 4-1 & Atts. (electric); DPU 22-9 & Att. (electric); DPU 22-10 & Att. (electric); DPU 22-11 & Att. (electric); DPU 22-12 & Att. (electric); DPU 42-37 & Atts. (electric); DPU 42-38 & Atts.

(electric); DPU 42-39 & Atts. (electric); DPU 42-40 & Atts. (electric); DPU 54-7 (electric); Schs. Unitil-KSTBCL-1 through Unitil-KSTBCL-12 (gas); Unitil-KSTBCL-14 through Unitil-KSTBCL-19 (gas); DPU 4-1 & Atts. (gas); DPU 28-7 (gas); DPU 28-8 (gas); DPU 28-9 (gas); DPU 32-1 & Atts. (gas)).

Further, to demonstrate cost control efforts, Unitil provided information regarding its capital planning and authorization procedures, which included the Company's current capital budget input and review processes and the corresponding levels of authorization by dollar threshold, as described above (Exhs. Unitil-KSTB-1, at 12-16 (electric); Schs. Unitil-KSTB-14; Unitil-KSTB-15 (electric); Unitil-KSTBCL-1, at 13-17 (gas); Schs. Unitil-KSTBCL-14 (gas); Unitil-KSTBCL-15 (gas)). In addition to maintaining the documentation required by the construction authorization policy, the record shows that the Company's project supervisors review and analyze every project on a monthly basis for actual spending versus authorized spending, prepare revised or supplemental authorizations for projects that are forecast to exceed 15 percent and $5,000 over the authorized amount, and re-route for approval as necessary (Exhs. Unitil-KSTB-1, at 13-14 (electric); DPU 22-3 (electric); DPU 42-36 (electric); Unitil-KSTBCL-1, at 14-15 (gas)).

The Attorney General argues that post-test-year plant additions should not be included in the Company's rate base and instead should be recovered through its capital tracker, i.e., the CCA (Attorney General Brief at 62-64). As set forth in Section III.D.5.f. above, the Department approves the Company's electric division a PBR plan with a K-bar mechanism to recover capital costs. Further, in Section XIII.A.2. below, the Department accepts the Company's proposal to transition from the CCA to PBR and to phase out the CCA mechanism. Consistent with the findings above and with the Department's recent precedent, we approve Unitil's proposal to include the Company's 2023 electric division plant additions in rate base without regard to the size of the plant additions in relation to rate base. D.P.U. 22-22, at 60-61, 129 n.66, 135-136. As set forth in Section III.D.4. above, the Department also approves a PBR plan for the Company's gas division. Consistent with Department precedent, the Department allows the Company's 2023 gas division plant additions in rate base without regard to the size of the plant additions in relation to rate base. D.P.U. 20-120, at 74-79; D.P.U. 19-120, at 169-170.

No intervenor challenged the prudency of the Company's proposed plant additions. Based on our review of the Company's testimony, capital authorization processes, and capital project supporting documentation, we find that Unitil's cost control measures are reasonable and appropriate, and that costs associated with the subject capital projects were prudently incurred, and the resulting plant additions are used and useful in providing service to ratepayers. Therefore, the Department will include the Company's electric and gas division capital additions placed in service between January 1, 2019 through December 31, 2023 in the Company's plant in service.[38]

C. Cash Working Capital Allowance

1. Introduction

The purpose of conducting a cash working capital lead-lag study is to determine a company's "cash in-cash out" level of liquidity to provide the company an appropriate allowance for the use of its funds. Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23

[38] The Department addresses the Company's CCA mechanism in Section XIII.A. below.

(1988). Such funds are either generated internally or through short-term borrowing. See D.P.U. 96-50 (Phase I) at 26. Department policy permits a company to be reimbursed for costs associated with the use of its funds and for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; D.P.U. 87-260, at 22. The Department requires all electric and gas companies serving more than 10,000 customers to conduct a fully developed and reliable O&M lead-lag study. Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 164 (2011). In the event that the lead-lag factor is not below 45 days, a company will face a high burden to justify the reliability of such a study and the reasonableness of the steps the company has taken to minimize all factors affecting cash working capital requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

2. Company Proposal

Unitil conducted a lead-lag study to determine its cash working capital requirements for its electric and gas divisions (Exhs. Unitil-CRD-2 (electric); Unitil-CRD-3 (electric); Unitil-CRD-2 (gas); Unitil-CRD-3 (gas)).[39] A lead-lag study compares the timing difference between (1) the incurrence of costs by a company and the company's subsequent payment of such costs ("expense lead") and (2) the receipt of service by customers, and the customer's

39 The cash working capital associated with purchased power expense and external transmission expense will be recovered through the Company's Basic Service Cost Adjustment provision, and the cash working capital associated with other operating electric operating expenses will be recovered through inclusion in the Company's rate base (Exh. Unitil-CRD-1, at 3 (electric)). The cash working capital associated with purchased gas expense will be recovered through the Company's Cost of Gas Adjustment provision, and the cash working capital associated with other gas operating expenses will be recovered through inclusion in the Company's rate base (Exh. Unitil-CRD-1, at 3 (gas)).

subsequent payment for these services ("revenue lag"). D.P.U. 11-01/D.P.U. 11-02, at 151. Each component of the Company's cash working capital allowance uses revenue lag days and expense lead days to determine the cash working capital requirement (Exhs. Unitil-CRD-1, at 5 (electric); Unitil-CRD-1, at 4 (gas)). Unitil conducted its lead-lag study using in-house personnel to update the net lag days associated with each component (Exhs. Unitil-CRD-1, at 1 (electric); Unitil-CRD-1, at 1 (gas)).

Unitil calculated a revenue lag to be used in its cash working capital net lag factors (Exhs. Unitil-CRD-1, at 6-7 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-1, at 5 (gas); Unitil-CRD-2, at 2 (gas)). The revenue lag consists of a "service lag," "collection lag," and a "billing lag" (Exhs. Unitil-CRD-1, at 5 (gas); Unitil-CRD-2, at 2 (gas); Unitil-CRD-1, at 6-7 (electric); Unitil-CRD-2, at 2 (electric)). The sum of the days associated with these three lag components is Unitil's total revenue lag (Exhs. Unitil-CRD-1, at 6-7 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-1, at 5 (gas); Unitil-CRD-2, at 2 (gas)).

Unitil calculated a service lag of 15.21 days for both the electric and gas divisions (Exhs. Unitil-CRD-1, at 7 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-1, at 5-6 (gas); Unitil-CRD-2, at 2 (gas)). This lag was derived by dividing the number of billing days in the test year by twelve months and dividing that total in half to arrive at the midpoint of the monthly service periods (Exhs. Unitil-CRD-1, at 7 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-1, at 5-6 (gas); Unitil-CRD-2, at 2 (gas)). The collection lag, which reflects the time delay between the mailing of customer bills and the receipt of the billing revenues from customers, totaled 42.36 days for the electric division and 56.14 days for the gas division (Exhs. Unitil-CRD-1, at 8 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-3, at 1 (electric); Unitil-CRD-1, at 6-7 (gas);

Unitil-CRD-2, at 2 (gas); Unitil-CRD-3, at 1 (gas)). The collection lag was derived by dividing the average daily accounts receivable balance by the average daily revenue amount (Exhs. Unitil-CRD-1, at 8 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-3, at 5 (electric); Unitil-CRD-1, at 5 (gas); Unitil-CRD-2, at 2 (gas); Unitil-CRD-3, at 5 (gas)). Finally, for both divisions the Company applied a billing lag of 1.07 days, based on the fact that customers are billed the day after meters are read and taking into consideration delays for weekends and holidays (Exhs. Unitil-CRD-1, at 7-8 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-3, at 3 (electric); Unitil-CRD-1, at 6 (gas); Unitil-CRD-2, at 2 (gas); Unitil-CRD-3, at 3 (gas)). Based on the foregoing, and by adding the number of days associated with each of the three revenue lag components, Unitil calculated a total revenue lag of 58.63 days for its electric division and 72.41 days for its gas division (Exhs. Unitil-CRD-1, at 9 (electric); Unitil-CRD-2, at 2 (electric); Unitil-CRD-3, at 1 (electric); Unitil-CRD-1, at 8 (gas); Unitil-CRD-2, at 2 (gas); Unitil-CRD-3, at 1 (gas)).

Unitil's O&M cash working capital is composed of O&M expense and other taxes (Exhs. Unitil-CRD-1, at 9-12 (electric); Unitil-CRD-2, at 1 (electric); Unitil-CRD-1, at 8-11 (gas); Unitil-CRD-2, at 1 (gas)). To calculate the O&M expense lead period, Unitil disaggregated its O&M expense into six major cost categories: labor-direct; labor-incentive; medical and benefits; regulatory commission expense; USC charges; and other O&M expenses (Exhs. Unitil-CRD-2, at 1 (electric); Unitil-CRD-2, at 1 (gas)).

Unitil reviewed test-year O&M-related payments and calculated the lead days for each category (Exhs. Unitil-CRD-1, at 6 (electric); Unitil-CRD-2, at 3 (electric); Unitil-CRD-1, at 4-5 (gas); Unitil-CRD-2, at 3 (gas)). Once Unitil determined lead days for each category, it used the sum of the lead days weighted by dollars to arrive at an O&M expense lead of 34.39 days for its electric division and 28.55 days for its gas division (Exhs. Unitil-CRD-1, at 9-12 (electric); Unitil-CRD-2, at 1 (electric); Unitil-CRD-1, at 8-11 (gas); Unitil-CRD-2, at 1 (gas)). For its electric division, the Company then subtracted the expense lead of 34.39 days from the revenue lag of 58.63 days to produce a net O&M expense lag of 24.24; for the gas division, the Company subtracted the expense lead of 28.55 days from the revenue lag of 72.41 days to produce a net O&M expense lag of 43.86 days (Exhs. Unitil-CRD-1, at 3-4, 13 (electric); Unitil-CRD-2, at 1 (electric); Unitil-CRD-1, at 3-4, 11 (gas); Unitil-CRD-2, at 1 (gas)).

For its electric division, the Company derived an O&M expense cash working capital factor of 6.64 percent by dividing the net lag days of 24.24 by 365 days (Exhs. Unitil-CRD-1, at 13 (electric); Unitil-CRD-2, at 1 (electric)). The Company multiplied this factor by the total costs applicable to cash working capital of $15,707,931 to calculate a cash working capital allowance of $1,043,035 (Exhs. Unitil-CRD-1, at 13 (electric); Sch. RevReq-4-5 (Rev. 4) (electric)). For the gas division, the Company derived an O&M expense cash working capital factor of 12.02 percent by dividing the net lag days of 43.86 by 365 days (Exhs. Unitil-CRD-1, at 11 (gas); Unitil-CRD-2, at 1 (gas)). The Company multiplied this factor by the total costs applicable to cash working capital of $11,173,244 to calculate a cash working capital allowance of $1,342,689 (Exh. Sch. RevReq-4-5 (Rev. 4) (gas)).

On brief, Unitil summarizes its lead-lag study calculations and cash working capital requirements and asserts that the Company's calculations are consistent with Department precedent (Company Brief at 252-253 (electric); Company Brief at 215-216 (gas)). No other party addressed Unitil's proposed cash working capital calculations on brief.

3. Analysis and Findings

The Department has reviewed the evidence in support of Unitil's lead-lag study, and we conclude that the Company properly calculated the electric division's total revenue lag of 58.63 days and the gas division's total revenue lag of 72.41 days (Exhs. Unitil-CRD-1, at 9 (electric); Unitil-CRD-2, at 1 (electric); Unitil-CRD-1, at 8 (gas); Unitil-CRD-2, at 1 (gas)). Further, the Department finds that the Company properly calculated the electric division's O&M and other taxes expense lead of 34.39 days and the resulting net lag of 24.24 days, and properly calculated the gas division's O&M and other taxes expense lead of 28.55 days and the resulting net lag of 43.86 days and (Exhs. Unitil-CRD-1, at 3-4, 13 (electric); Unitil-CRD-2, at 1 (electric); Unitil-CRD-1, at 3-4, 11 (gas); Unitil-CRD-2, at 1 (gas)).

Unitil's proposed O&M net lag factors of 24.24 days for its electric division and 43.86 days for its gas division are lower than the Department's 45-day convention (Exhs. Unitil-CRD-1, at 3-4, 13 (electric); Unitil-CRD-2, at 1 (electric); Unitil-CRD-1, at 3-4, 11 (gas); Unitil-CRD-2, at 1 (gas)). Additionally, we find that Unitil's decision to perform a lead-lag study with in-house personnel was a cost-effective means to determine its cash working capital requirement (Exhs. Unitil-CRD-1, at 1 (electric); Unitil-CRD-1, at 1 (gas)). D.P.U. 22-22, at 140; Bay State Gas Company, D.P.U. 12-25, at 97 (2012). For these reasons, the Department accepts the Company's lead-lag studies and the resulting O&M cash working capital factor of 6.64 percent for the electric division (24.24 days/365 days) and 12.02 percent for the gas division (43.86 days/365 days).

As noted above, application of the O&M cash working capital factor of 6.64 percent to the level of O&M and other taxes authorized by this Order produces a cash working capital allowance for the electric division of $1,060,317. Application of the O&M cash working capital factor of 12.02 percent to the level of O&M and other taxes authorized by this Order produces a cash working capital allowance for the gas division of $1,362,546. The derivation of the cash working capital allowances is provided in the division-specific Schedule 6 below.

D. Accumulated Deferred Income Taxes

1. Introduction

The Company's accumulated deferred income taxes ("ADIT") consist of federal and state deferred income taxes and are recorded in subaccounts of Account 283 (RR-DPU-41, Att. 1, at 4, 16-17). These subaccounts include plant-related ADIT and non-plant-related ADIT (Tr. 6, at 588; RR-DPU-41, Att. 1, at 16-17).[40]

Unitil proposes for its electric division an ADIT balance of $11,650,499, comprising $11,867,825 in ADIT associated with utility plant and $335,477 in ADIT associated with non-plant items, less $552,803 in ADIT associated with its Statement of Financial Accounting Standard ("FAS") 109 regulatory asset[41] (Exhs. Sch. RevReq-4 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (electric); Sch. RevReq-4-7 (Rev. 4) (electric)). Unitil proposes for its gas division an ADIT balance of $19,268,801, comprising $19,576,047 in ADIT associated with

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40 Plant-related ADIT results from the differences between accelerated depreciation expense and depreciation expense on utility plant (Tr. 6, at 588). Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 33 (2001); Essex County Gas Company, D.P.U. 87-59, at 27 (1987).

41 FAS 109 establishes financial accounting and reporting standards for the effects of income taxes, including the recognition and treatment of deferred taxes. The regulatory asset is shown as a negative amount because while ADIT is booked to a liability account, the Company's presentation of ADIT in its cost-of-service schedules is represented as a positive entry (Exh. Sch. RevReq-4-6 (Rev. 4) (electric)).

utility plant and $358,283 in ADIT associated with non-plant items, less $665,529 associated with its FAS 109 regulatory asset (Exhs. Sch. RevReq-4 (Rev. 4) (gas); Sch. RevReq-4-6 (Rev. 4) (gas); Sch. RevReq-4-7 (Rev. 4) (gas)). During the proceeding, the Company updated its test-year-end ADIT balances to ADIT balances as of December 31, 2023, adjusted for what the Company considered to be known and measurable changes through June 30, 2024 (Exhs. Sch. RevReq-4-6 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (gas); Tr. 6, at 595-596).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company improperly adjusted the ADIT balances to reflect estimates of 2023 activity and incorrectly includes 2023 ADIT balances in the proposed rate base (Attorney General Brief at 64, citing Exh. AG-LKM-1, at 10). The Attorney General asserts that the Company's adjustment is inconsistent with Department precedent and the Department should eliminate any 2023 estimated activity from ADIT (Attorney General Brief at 64). Additionally, the Attorney General maintains that the Company's electric division has an existing capital tracker, which already provides for recovery of all post-test-year amounts related to capital additions and thereby obviates the need for any post-test-year adjustments in the base distribution rate case (Attorney General Brief at 64).

b. Company

On brief, Unitil summarizes its ADIT calculations (Company Brief at 253-254 (electric); Company Brief at 217-218 (gas)).

3. Analysis and Findings

a. Introduction

Deferred income taxes arise because of the differences between the tax and book treatment of certain transactions, including the use of accelerated depreciation and the treatment of certain operating expenses for income tax purposes. Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 33 (2001); Essex County Gas Company, D.P.U. 87-59, at 27 (1987). This accumulated balance of interest-free funds is available to the utility to further invest until it is then needed to fund the taxes due and payable in later years. Therefore, deferred income taxes represent an offset to rate base. D.P.U. 87-59, at 63; AT&T Communications of New England, D.P.U. 85-137, at 31 (1985); Boston Edison Company, D.P.U. 1350, at 42-43 (1983); Boston Edison Company, D.P.U. 18200, at 33-34 (1975). Nonetheless, the Department has a general policy of matching the recovery of tax benefits and losses to the recovery of the underlying expense with which the tax effects are associated. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 29 (1991); Massachusetts Electric Company, D.P.U. 89-194/195, at 66 (1990).

b. Plant Related ADIT

From the updated ADIT balances, the Company deducted amounts related to costs that are treated as below-the-line activities and costs recovered outside of base distribution rates, such as through reconciling mechanisms, to derive the ADIT associated with base distribution rates (Exhs. Sch. RevReq-4-6 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (gas)). In addition, the Company included in its pro forma adjustments the first six months of ADIT roll-forward amounts in 2024, related to distribution cost recovery items outside of base distribution rates that the Company proposes to roll into base distribution rates in this instant proceeding (Exhs. Unitil-CGDN-1, at 4, 16 (electric); Sch. RevReq-4-7 (Rev. 4) (electric); Unitil-CGDN-1, at 4, 7-9 (gas); Sch. RevReq-4-7 (Rev. 4) (gas)).[42] Unitil also excluded ADIT associated with advanced metering infrastructure ("AMI") costs, because the Company proposes to recover these through a separate reconciliation factor outside of base distribution rates (see Section X. below). For the electric division, the ADIT balance was further adjusted to exclude the amount assigned to internal transmission (Exh. Sch. RevReq-4-6 (Rev. 4) (electric)).

Consistent with the allowed 2023 update of the electric plant additions in Section V.B.5. the Department also recognizes the ADIT associated with that plant. The Department has reviewed the Company's proposed ADIT for the electric division and accepts the Company's calculations on the ADIT associated with the 2023 plant additions. Additionally, the Company proposes roll-forward adjustments of $78,583 and negative $21,900 for January 1, 2024 through June 30, 2024 to account for the activities associated with CCA and SCA, respectively (Exhs. Unitil-CGDN-1, at 68 (electric); Sch. RevReq-4-7 (Rev. 4) (electric)). Consistent with the Department's decision to allow the roll-in of these investments in Sections XIII.A.2. and XIII.D.2., the Department accepts the roll-forward adjustments presented by the Company. Finally, consistent with the Department's decision to transfer the recovery of all costs related to AMI from base distribution rates to the GMF as described in Section X. below, the Department accepts the AMI adjustment presented by the Company (Exh. Sch. RevReq-4-6 (Rev. 4)

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[42] Specifically, the Company proposed to roll into base distribution rates costs currently being recovered through its CCA, SCA, and GSEP reconciling mechanisms (Exhs. Unitil-CGDN-1, at 4, 16 (electric); Unitil-CGDN-1, at 4, 7-9 (gas)).

(electric)). Accordingly, the Department allows the Company's proposed plant-related ADIT for the electric division (Exhs. Sch. RevReq-4 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (electric); Sch. RevReq-4-7 (Rev. 4) (electric)).

Consistent with the Department's approval of the gas division's post-test-year plant additions in Section V.B.5., the Department accepts the Company's calculations on the ADIT associated with the 2023 plant additions (excluding 2023 GSEP plant additions). The Department has reviewed the Company's proposed ADIT for the gas division and accepts the Company's ADIT calculations. Additionally, the Company proposes a roll-forward adjustment of negative $9,377 for January 1, 2024 through June 30, 2024 to account for the activities associated with GSEP plant as of the test-year-end for plant-related ADIT at June 30, 2024 (Exhs. Unitil-CGDN-1, at 8-9 (gas); Sch. RevReq-3 (gas); Sch. RevReq-4-7 (Rev. 4) (gas)). Consistent with the Department's decision to allow the roll-in of the GSEP investment as of the test-year-end in Section V.G.2. below, the Department accepts the roll-forward adjustment presented by the Company. Accordingly, the Department allows the Company's proposed total plant-related ADIT balance for the gas division (Exhs. Sch. RevReq-4 (gas); Sch. RevReq-4-6 (Rev. 4) (gas); Sch. RevReq-4-7 (Rev. 4) (gas)).

c. <u>Non-Plant Related ADIT</u>

The Company's proposed non-plant-related ADIT includes ADIT associated with deferred rate case costs and FAS 109 federal and state income taxes (Exhs. Sch. RevReq-4-6 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (gas)). Additionally, the Company proposes a zero balance in base distribution rates for pension and PBOP related ADIT (Exhs. Sch. RevReq-4-6 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (gas)).

i. Deferred Rate Case Costs

Deferred rate case costs represent cash expenditures made in previous rate cases that have not yet been recovered from the ratepayers (Tr. 6, at 582). The Department has previously determined that deferred income taxes associated with a deferred expense are excluded from the calculation of rate base because ratepayers have not been burdened with the costs. D.P.U. 89-114/90-331/91-80 (Phase One) at 24-30; D.P.U. 89-194/195, at 66. Accordingly, the Department will exclude the ADIT associated with deferred rate case costs from the calculation of the Company's ADIT rate base offset for the Company's electric and gas divisions. Therefore, the Department decreases the ADIT balance by $117,036 for the electric division and $132,140 for the gas division.

ii. Pension and Post-Retirement Benefits Other than Pension

In its non-plant-related ADIT proposal, the Company excludes the ADIT associated with pension and PBOP expenses because they are currently recovered outside of base distribution rates (Exhs. Unitil-CGDN-1, at 65 (electric); Unitil-CGDN-1, at 52 (gas)). As discussed in Section VII.E. below, however, the Department has eliminated the pension adjustment mechanism ("PAM") in favor of recovery of all pension and PBOP expense through base distribution rates. Consistent with this treatment, the Department finds it appropriate to include ADIT associated with pension and PBOP expense in the Company's rate base.

As of the end of the test year, the Company reported that its electric division had an ADIT balance of $1,008,169 related to pension expense and $372,281 related to PBOP expense (Exh. Sch. RevReq-4-6 (electric)). During the proceeding, the Company reported that as of the end of 2023, its electric division had an ADIT balance of $1,122,455 related to pension expense and $276,982 related to PBOP expense (Exh. Sch. RevReq-4-6 (Rev. 4) (electric)). These amounts correspond to the sum of the deferred federal and state income taxes related to pension and PBOP expenses recorded in the Account 283 in the Company's 2023 chart of accounts (Exh. AG 1-34, Att. 2, at 16-17 (electric); RR-DPU-41, Att. 1, at 16-17 (electric)). Among the pension and PBOP expenses related subaccounts of Account 283, there are regulatory asset entries, i.e., $366,694[43] related to pension expense and $585,415[44] related to PBOP expense at the end of 2023, that represent the result of the Company's recording of accrued revenue (Exh. AG 1-34, Att. 2, at 16-17 (electric); Tr. 6, at 580-581 (electric); RR-DPU-41, Att. 1, at 16-17 (electric)). As previously noted, ADIT represents interest-free funds from ratepayers. D.P.U. 87-59, at 63; D.P.U. 85-137, at 31; D.P.U. 1350, at 42-43; D.P.U. 18200, at 33-34. Therefore, in considering the proper ADIT related to pension and PBOP expenses for the electric division, the Department allows the Company's ADIT with only the deferred taxes resulting from the pension and PBOP expenses, resulting in the amounts of $699,060[45] associated with pension and negative $285,293[46] associated with PBOP at the end of 2023 (RR-DPU-41, Att. 1, at 16-17 (electric)).

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43 $259,316 + $107,378 = $366,694 (RR-DPU-41, Att. 1, at 16-17 (electric))

44 $413,991 + $171,424 = $585,415 (RR-DPU-41, Att. 1, at 16-17 (electric))

45 The sum of the deferred federal income taxes of $534,454 and the deferred state income taxes of $221,306 associated with pension expense at the end of 2023 multiplied by the percentage associated with base rates, i.e., 1 – 7.5024 percent, equals $699,060 (Exh. Unitil-WP-1 (Rev. 4) (electric); RR-DPU-41, Att. 1, at 16-17 (electric)).

46 The sum of the deferred federal income taxes of negative $218,115 and the deferred state income taxes of negative $90,318 associated with PBOP expense at the end of 2023

Similarly, for the gas division, the Company provided the total ADIT related to pension and PBOP at the test-year end and at the end of 2023 corresponding to the amounts shown in its chart of accounts, which include the amounts resulting from the Company's recording of accrued revenue (Exhs. Sch. RevReq-4-6 & Revs. 1-4 (gas); AG 1-34, Att. 2, at 4 (gas); RR-DPU-41, Att. 1, at 4 (gas)). Among the pension and PBOP expenses related subaccounts of Account 283, there are regulatory asset entries, i.e., $327,711[47] related to pension expense and $586,725[48] related to PBOP expense at the end of 2023, that represent the result of the Company's recording of accrued revenue (Tr. 6, at 580-581 (electric); RR-DPU-41, Att. 1, at 4 (gas)). Therefore, in considering the proper ADIT related to pension and PBOP expenses for the gas division, the Department allows the Company's ADIT with only the deferred taxes resulting from the pension and PBOP expenses. The Department adjusts the non-plant related ADIT to include $757,630[49] associated with pension and negative $353,888[50] associated with PBOP at the end of 2023, because the ADIT only includes amounts related to pension and PBOP expenses (RR-DPU-41, Att. 1, at 4 (gas)).

multiples the ratio associated with base rates, i.e., 1 – 7.5024 percent, equals negative $285,293 (Exh. Unitil-WP-1 (Rev. 4) (electric); RR-DPU-41, Att. 1, at 16-17 (electric)).

47 $231,749 + $95,962 = $327,711 (RR-DPU-41, Att. 1, at 4 (gas))

48 $414,917 + $171,808 = $586,725 (RR-DPU-41, Att. 1, at 4 (gas))

49 $757,630 is the sum of the deferred federal income taxes of $535,776 and the deferred state income taxes of $221,854 associated with pension expense at the end of 2023 (RR-DPU-41, Att. 1, at 4 (gas)).

50 Negative $353,888 is the sum of the deferred federal income taxes of negative $250,261 and the deferred state income taxes of negative $103,627 associated with PBOP expense at the end of 2023 (RR-DPU-41, Att. 1, at 4 (gas)).

iii. FAS 109 Regulatory Asset

The FAS 109 regulatory asset originated from the Company's implementation of FAS 109 in February 1992 and the revaluation of deferred taxes associated with the increase of the Massachusetts state corporate income tax rate from 6.5 percent to 8.0 percent in 2013 (Exhs. DPU 11-1 & Att. 1 (electric); DPU 9-1 & Att. 1 (gas)). FAS 109 regulatory asset amortization amounts have been included in previous base distribution rate cases (Exhs. DPU 11-1 (electric); DPU 9-1 (gas)). D.P.U. 15-80/D.P.U. 15-81, at 240-241; D.P.U. 13-90, at 198-200; D.P.U. 11-01/D.P.U. 11-02, at 497.

For the electric division, the test-year-end FAS 109 regulatory asset balance recorded in subaccounts to Account 182 is $597,640, according to the Company's chart of accounts (Exhs. AG 1-34, Att. 2, at 16 (electric); DPU 11-1 (electric); RR-DPU-41, Att. 1, at 16 (electric)). The Company includes in its Account 182 balance an accrual of $368,288 from Account 173, representing the sum of the next twelve month of amortizations, resulting in an additional year of amortization being included in the test-year end balance (Exhs. DPU 11-1, Att. 2 (Rev.) (electric); DPU 42-16 (electric); RR-DPU-41, Att. 1, at 16 (electric)). Therefore, the balance proposed by the Company represents the balance at the end of 2023. After adjusting for internal transmission of 7.5024 percent, the FAS 109 regulatory asset balance at the end of 2023 is $552,803[51] (Exh. Sch. RevReq-4-6 (Rev. 4) (electric); RR-DPU-41, Att. 1, at 16 (electric)). The Company proposes to decrease its ADIT by the FAS 109 regulatory asset balance of $552,803 (Exh. Sch. RevReq-4-6 (Rev. 4) (electric)). Because the unamortized

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51 $597,640 x (1 – 7.5024 percent) = $552,803

FAS 109 regulatory asset balance represents the amount to be collected from the customers, the Department finds the Company's proposal is reasonable. D.P.U. 87-59, at 63; D.P.U. 85-137, at 31; D.P.U. 1350, at 42-43; D.P.U. 18200, at 33-34. However, the balance recorded in Account 182 includes $151,026 in tax gross-ups recorded in Account 254 (Exh. DPU 11-1 & Att. 1 (electric)).[52] As such, the Department will exclude the tax gross-ups from the balance, producing a FAS 109 regulatory asset balance of $401,777 for the electric division.[53]

For the gas division, the test-year-end FAS 109 regulatory asset balance recorded in subaccounts of Account 182 is $665,529 according to the Company's chart of accounts (Exhs. AG 1-34, Att. 2, at 3 (gas); DPU 9-1 (gas); RR-DPU-41, Att. 1, at 3 (gas)). The Company includes in its Account 182 balance accrued revenues of $211,188 from Account 173 representing the sum of the next twelve months of amortizations, resulting in an additional year of amortization being included in the proposed balance (Exhs. DPU 9-1, Att. 2 (Rev.) (gas); DPU 34-21 (gas); RR-DPU-41, Att. 1, at 3 (gas)). Therefore, the balance represents the balance at the end of 2023. The Company proposes to decrease ADIT by the FAS 109 regulatory asset balance of $665,529 (Exh. Sch. RevReq-4-6 (Rev. 4) (gas)). Because the unamortized FAS 109 regulatory asset balance represents the amount to be collected from the customers, the Department finds the Company's proposal is reasonable. D.P.U. 87-59, at 63; D.P.U. 85-137, at 31; D.P.U. 1350, at 42-43; D.P.U. 18200, at 33-34. However, the balance recorded in

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52 According to the Company, the asset Account 182 records the total regulatory asset, and the liability Account 254 records the gross-up portion of the regulatory asset (Exh. DPU 11-1, Att. 1 (electric)).

53 $552,803 – $552,803 x (21 percent x (1 – 8 percent) + 8 percent) = $552,803 – $151,026 = $401,777

Account 182 includes $181,823 in tax gross-ups recorded in Account 254 (Exh. DPU 9-1 & Att. 1 (gas)).[54] As such, the Department adjusts the FAS 109 regulatory asset balance to $483,706 to exclude grossed-up taxes of $181,823.[55]

d. Conclusion

Based on the above analysis, the Department finds that the total ADIT for Unitil's electric division is $12,098,256, comprising $11,867,825 in plant-related ADIT and $632,208 in non-plant-related ADIT, less $401,777 in FAS 109 regulatory assets. The total ADIT for the Company's gas division is $19,722,226, comprising $19,576,047 for plant-related ADIT and $629,885 for non-plant related ADIT, less $483,706 in its FAS 109 regulatory assets. The Company has proposed ADIT balances of $11,650,499 for its electric division and $19,268,801 for its gas division (Exhs. Sch. RevReq-4 (Rev. 4) (electric); Sch. RevReq-4 (Rev. 4) (gas)). Accordingly, the Department increases the Company's electric division rate base ADIT offset by $447,757 and increases the Company's gas division rate base ADIT offset by $453,425.

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54 According to the Company, the asset Account 182 records the total regulatory asset, and the liability Account 254 records the gross-up portion of the regulatory asset (Exh. DPU 9-1, Att. 1 (gas)).

55 $665,529 – ($665,529 x (21 percent x (1 – 8 percent) + 8 percent) = $665,529 – $181,823 = $483,706

E. Excess Accumulated Deferred Income Taxes

1. Introduction

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 ("2017 TCJA") was signed into law.[56] In relevant part, the 2017 TCJA reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. Pub. L. No. 115-97, § 13001. On February 2, 2018, the Department, pursuant to G.L. c. 164, §§ 76, 93, 94 and G.L. c. 165, §§ 2, 4, opened an investigation into the effect on rates of the decrease in the federal corporate income tax rate on the Department's regulated utilities. Effect of Reduction in Federal Income Tax Rates on Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15, Order Opening Investigation (February 2, 2018).[57]

The Department determined that for certain regulated utilities, including the Company, the reduction in the federal corporate income tax rate resulted in booked ADIT that was in excess of future liabilities. D.P.U. 18-15, Order Opening Investigation at 4. Thus, as part of the investigation, certain regulated utilities, including the Company, were directed to file a proposal to refund to ratepayers the balance of excess ADIT as of December 31, 2017. D.P.U. 18-15, Order Opening Investigation at 5. On September 24, 2018, the Department approved the Company's proposal to return to ratepayers the balance of protected excess ADIT.

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56 Pub. L. No. 115-97, 131 Stat. 2054: An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018.

57 For a complete background and procedural history, refer to D.P.U. 18-15-A at 1-7.

D.P.U. 18-15-D at 17-21.[58] On December 21, 2018, the Department directed the Company to refund excess ADIT to ratepayers through a 2017 Tax Act Credit Factor ("TACF") to be included as a separate reconciling component in the Company's annual rate adjustment/reconciliation filing for the electric division and in the Company's local distribution adjustment clause for the gas division. D.P.U. 18-15-E at 47.

As part of a settlement in the Company's previous base distribution rate cases for its operating divisions, the Department allowed the Company to eliminate the TACF and instead refund excess ADIT through base distribution rates for its electric and gas divisions. D.P.U. 19-130, at 7-8; D.P.U. 19-131, at 7-8. As a result, the TACF was eliminated effective November 1, 2020, for the electric division and effective March 1, 2020, for the gas division. D.P.U. 19-130, at 7; D.P.U. 19-131, at 7-8.

2. Company Proposal

Unitil proposes for its electric division an accumulated excess ADIT balance of $4,269,516 (Exhs. Sch. RevReq-3 (Rev. 4) (electric); Sch. RevReq-4 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 1) (electric); Sch. RevReq-4-7 (Rev. 2) (electric)). The Company proposes for its gas division an accumulated excess ADIT balance of $5,575,350 (Exhs. Sch. RevReq-3 (Rev. 4) (gas); Sch. RevReq-4 (Rev. 4) (gas); Sch. RevReq-4-6 (Rev. 1) (gas); Sch. RevReq-4-7 (Rev. 4) (gas)). On brief, Unitil summarizes its excess ADIT calculations (Company Brief at 255 (electric); Company Brief at 218 (gas)). No other party addressed Unitil's excess ADIT proposals on brief.

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[58] The Internal Revenue Service classifies certain plant-related excess ADIT as "protected" and subject to specific normalization rules. Pub. L. No. 115-97, § 1561(d)(1), (2).

3. Analysis and Findings

As a result of the 2017 TCJA federal corporate income tax rate reduction, the excess ADIT represents a portion of ADIT that is no longer owed to the government by virtue of the lower tax rates effective January 1, 2018. D.P.U. 18-15-D at 13; D.P.U. 18-15, Order Opening Investigation at 1-2. Nevertheless, the excess ADIT remains on the Company's books, and thus represents an offset to the Company's rate base for the same reason that other ADIT represents an offset to the Company's rate base. D.P.U. 18-15-E at 46.

As of the end of 2023, Unitil reported for its electric division an excess ADIT balance related to pension and PBOP of negative $409,728 before the tax gross-up and negative $563,742 after the tax gross-up and, for its gas division, an excess ADIT balance of negative $324,987 before the tax gross-up and negative $447,148 after the tax gross-up (Exhs. Sch. RevReq-4-6 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (gas)). According to the Company's 2017 TCJA implementation plan, the excess ADIT was created through an additional $12 million pension contribution made on September 7, 2018,[59] and included in its 2017 federal and state tax returns (Exhs. DPU 14-2, Att. at 66 (electric); DPU 12-1, Att. at 66 (gas)). Unitil's decision to make additional pension contributions for plan year 2017 was made after discussions with the Company's actuary on May 17, 2018, and after the Company's participation in conference calls with other New England utilities during the first quarter of 2018 (Exhs. DPU 14-2, Att. at 25, 58 (electric); DPU 12-1, Att. at 25, 58 (gas)). The additional

59 The deadline for contributions to a pension plan is eight and a half months after the close of the plan year; if there is no minimum contribution required, the contribution can be designated for either the prior or current plan year. 26 C.F.R. § 1.430(j)-1.

pension contributions contributed to a net operating loss in 2017 (Exhs. DPU 14-2, Att. at 53-54, 58 (electric); DPU 12-1, Att. at 53-54, 58 (gas)). In a subsequent re-evaluation of its net operating loss, the Company determined that the excess ADIT associated with its pension was a negative $1.4 million (Exhs. DPU 14-2, Att. at 21, 69 (electric); DPU 12-1, Att. at 21, 69 (gas)). As a result, the Company's PAM filings incorporated additional amounts of excess ADIT related to the 2017 TCJA that would be paid by customers (Exhs. DPU 14-3, Att. (electric); DPU 12-2, Att. (gas)). Fitchburg Gas and Electric Light Company, D.P.U. 23-76, Exh. Sch. PAF-1, at 2 (2023); Fitchburg Gas and Electric Light Company, D.P.U. 22-97, Exh. Sch. PAF-1, at 2 (2022); Fitchburg Gas and Electric Light Company, D.P.U. 21-94, Exh. Sch. PAF-1, at 2 (2021); Fitchburg Gas and Electric Light Company, D.P.U. 20-87, Exh. Sch. PAF-1, at 2 (2020).

The Company maintains that the additional costs to customers are due to deficiencies in its excess ADIT balance associated with pension and PBOP balances (Tr. 6, at 596-598). The Department disagrees with the Company's treatment of its pension-related excess ADIT. The Department previously ordered the Company to refund the excess ADIT resulting from the 2017 TCJA through reconciling mechanisms for amounts related to those costs recovered outside of base distribution rates so that Massachusetts customers received a prompt benefit of the federal income tax decrease. D.P.U. 18-15-F at 15; D.P.U. 18-15-E at 47. Because the excess ADIT represents interest-free funds from ratepayers, it is inappropriate for the Company to collect additional charges from ratepayers as a result of the federal income tax decrease. D.P.U. 87-59, at 63; D.P.U. 85-137, at 31; D.P.U. 1350, at 42-43. Accordingly, the Department directs the Company to eliminate in its entirety the negative refund of excess ADIT associated with pension and PBOP. The effect of this adjustment is provided below.

For the electric division, Unitil records excess ADIT as a regulatory liability balance of $4,634,150 recorded to a subaccount to Account 254, and a short-term regulatory liability of $676,515 recorded to a subaccount to Account 242 representing the amount scheduled to be refunded in 2024 (RR-DPU-41, Att. 1, at 16-17 (electric)). The sum of these accounts is $5,310,665, which corresponds to the 2023 year-end balance the Company provided during the proceeding (Exh. DPU 14-3, Att. (electric); RR-DPU-41, Att. 1, at 16-17 (electric)). This balance includes a tax gross-up of $1,450,877 recorded in a subaccount to Account 283, resulting in an overall excess ADIT balance of $3,859,789 (RR-DPU-41, Att. 1, at 16-17 (electric)). The differences of the Company's calculations presented in its cost-of-service schedule are due to its inclusion of additional account balances related to transmission that are recorded separately in subaccounts 2540504 and 2830504 according to the Company's chart of accounts (Exh. Sch. RevReq-4-6 (Rev. 4) (electric); RR-DPU-41, Att. 1, at 16-17 (electric)). Therefore, to derive the Company's excess ADIT balance, the Department relies on the information provided in the response and attachment to information request DPU 14-3 (electric) and its chart of accounts without the additional transmission adjustments presented in the cost-of-service schedule (Exh. DPU 14-3, Att. (electric); RR-DPU-41, Att. 1, at 16-17 (electric)). Because the 2023 year-end amount includes a negative liability balance of $409,728 related to pension and PBOP, the rate year excess ADIT balance is increased to $4,269,517 (Exh. Sch. RevReq-4-6 (Rev. 4) (electric)).

Because the Department has directed the Company to eliminate the excess ADIT associated with pension and PBOP in its entirety, the Department increases the excess ADIT balance by $139,963[60] representing negative refunds as of the end of 2023 and producing an overall excess ADIT balance of $4,409,480 (RR-DPU-32, Att. (electric)). Accordingly, the Department increases the Company's proposed excess ADIT balance associated with its electric division by $139,963.

For the gas division, Unitil records excess ADIT as a regulatory liability balance of $6,480,611 recorded to a subaccount to Account 254, and a short-term regulatory liability of $743,334 recorded to a subaccount to Account 242 representing the amount scheduled to be refunded in 2024 (RR-DPU-41, Att. 1, at 4 (gas)). The sum of these accounts is $7,233,945, which corresponds to the 2023 year-end balance the Company provided during the proceeding (Exhs. DPU 12-2, Att. (gas); RR-DPU-41, Att. 1, at 4 (gas)). This balance includes a tax gross-up of $1,973,582 recorded in a subaccount to Account 283, resulting in an overall excess ADIT balance of $5,250,363 at the end of 2023 (RR-DPU-41, Att. 1, at 4 (gas)). Consistent with the Department's treatment of the Company's negative liability balance associated with pension and PBOP for its electric division, the Department eliminates the negative liability balance of $324,987 related to pension and PBOP for the Company's gas division. This adjustment produces a revised test-year end excess ADIT balance of $5,575,350 (Exh. Sch. RevReq-4-6 (Rev. 4) (gas)).

Because the Department has directed the Company to eliminate the excess ADIT associated with pension and PBOP in its entirety, the Department increases the excess ADIT

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60 $30,828 + $33,995 + $36,319 + $38,820 = $139,963 (RR-DPU-32, Att. (electric))

balance by $126,431[61] representing the negative refunds as of the end of 2023 and producing an overall excess ADIT balance of $5,701,781 (RR-DPU-32, Att. (gas)). Accordingly, the Department increases the Company's proposed excess ADIT balance associated with its gas division by $126,431.

F. Contributions in Aid of Construction – Gas Division

1. Introduction

Contributions in aid of construction ("CIAC") are defined as donations or contributions in cash, services, or property from states, municipalities or other governmental agencies, individuals, and others for construction purposes. See 220 CMR 50.00, Uniform System of Accounts for Gas Companies ("USOA-Gas"), Balance Sheet Accounts, Account 271.[62] Between January 1, 2015 and December 31, 2022, the Company collected $134,450 in CIAC (Exh. DPU 17-1, Att. at 2 (gas)). The Company credits CIAC contributions against Account 107, Construction Work in Progress, thus serving to reduce plant in service by the CIAC payments once that plant is completed and placed into service (Exh. DPU 17-1 (gas); Tr. 8, at 819-820, 821). Consequently, as of the end of the test year, the Company reported a zero balance in Account 271 (Exh. DPU 17-1 (gas)).[63]

61 $31,145 + $32,010 + $31,757 + $31,519 = $126,431 (RR-DPU-32, Att. (gas))

62 The USOA-Gas is informally referred to as the "Brown Book." D.P.U. 12-25, at 110 n.65.

63 The Company's annual returns to the Department indicate negative balances for this account (Exhs. DPU 17-1 (gas); AG 1-2, Att. 7.04, at 8 (gas); Tr. 8, at 822). These balances represent deferred income taxes associated with CIAC (Exh. AG 1-2, Att. 7.04, at 8 (gas); RR-DPU-37).

During the proceedings, the Company stated that it was amenable to booking CIAC in a different manner from its current practice, through the use of subaccounts as approved by the Department in Boston Gas Company and Colonial Gas Company, D.P.U. 17-170 (2018) and D.P.U. 12-25 (Tr. 8, at 825-826).[64] The Company indicated that while its CIAC records went back to 1992, much of the associated plant had likely been retired during the interceding years (Tr. 8, at 826-827). Neither Unitil nor any intervenor addressed this issue on brief.

2. Analysis and Findings

Under long-standing Department practice, property that has been contributed to a utility is not included in rate base. NSTAR Gas Company, D.P.U. 14-150, at 106-109 (2015); New England Gas Company, D.P.U. 10-114, at 100-101 (2011); Milford Water Company, D.P.U. 771, at 21(1982); Oxford Water Company, D.P.U. 18595, at 7-8 (1976); Commonwealth Gas Company, D.P.U. 18545, at 2-4 (1976); Hingham Water Company, D.P.U. 16054 (1969). This ratemaking treatment is intended to recognize that a utility is not entitled to a return on investment that was paid for by customers; otherwise, ratepayers would end up paying twice for the same plant - once through the contribution, and again through a return of and on the plant through depreciation and return on rate base. D.P.U. 10-114, at 100-101; D.P.U. 771, at 21-22.

General Laws c. 164, § 81, requires gas and electric companies to maintain their books and accounts in a manner prescribed by the Department. The need to ensure accounting

[64] Under this approach, a company creates a new subaccount to Account 101, Utility Plant in Service, which would offset all CIAC that is currently embedded in that company's plant accounts and allow the balance in Account 101 to remain unchanged. D.P.U. 17-170, at 62; D.P.U. 12-25, at 112. The company continues to record CIAC as a credit against plant, but the CIAC would be booked to the new subaccount, with an offsetting credit to Account 271. D.P.U. 17-170, at 62; D.P.U. 12-25, at 112.

uniformity, as well as to facilitate the Department's ability to exercise its general supervisory authority over the industries that it regulates, warrants the use of a standardized system of accounts for the companies subject to this agency's jurisdiction. New England Gas Company, D.P.U. 08-35, at 43-44 (2009); Aquaria LLC, D.T.E. 04-76, at 21 (2005); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240-A, Introductory Letter (May 19, 1941); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 104, Introductory Letter (May 27, 1921); Second Annual Report of the Board of Gas Commissioners, 2 Ann. Rep. Mass. Gas Comm. at 61, App. B (1887). The Department has long prescribed its own accounting system for gas companies in the form of the USOA-Gas and its predecessors. 220 CMR 50.00.[65] The Department's accounting regulations, not those of FERC, govern the Company's operations in Massachusetts.

The Company uses Account 271 to book deferred income taxes associated with CIAC (Exh. AG 1-2, Att. 7.04, at 8 (gas); RR-DPU-37). The USOA-Gas specifies that Account 271 "shall include donations or contributions in cash, services, or property from states, municipalities or other governmental agencies, individuals, and others for construction purposes." 220 CMR 50.00, USOA-Gas, Balance Sheet Accounts, Account 271. The associated instructions contained in the USOA-Gas are unambiguous on this point:

> Gas plant contributed to the utility or constructed by it from contributions to it of cash or its equivalent shall be charged to the gas plant accounts at cost of construction, estimated if not known. There shall be credited to the accounts for reserves for depreciation and amortization the estimated amount of depreciation and amortization applicable to the

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65 The Department has adopted the Uniform System of Accounts for Electric Companies prescribed by FERC with several modifications. 220 CMR 51.01(1). The Department, however, has not adopted FERC's Uniform System of Accounts for Gas Companies. 220 CMR 50.00.

> property at the time of its contribution to the utility. The difference between the amounts included in the electric plant accounts and the amounts credited to the reserves for depreciation and amortization shall be credited to Account 271, Contributions in Aid of Construction.

220 CMR 50.00, USOA-Gas, Gas Plant Instructions; § 2.E.

Under this instruction, CIAC, whether in the form of contributed property or cash received for construction, is added to the plant account, and any accumulated depreciation associated with CIAC in the form of contributed property accrued up to the time the associated property is transferred to the utility is booked to the depreciation reserve account. The remaining difference is booked to Account 271. The Department has consistently required that CIAC be booked to Account 271 to ensure accounting transparency for ratemaking purposes. D.P.U. 12-25, at 114; D.P.U. 08-35, at 44-45; New England Gas Company, D.P.U. 07-46, at 9 (2007).

Rather than require gas companies to adjust their books to properly record all CIACs associated with plant currently in service, the Department has accepted the use of an alternative accounting treatment involving the use of subaccounts. D.P.U. 19-120, at 193-196; D.P.U. 17-170, at 60-62; D.P.U. 12-25, at 111-112, 115. Under this approach, the Company would create a new subaccount to Account 101, Utility Plant in Service, which would offset all CIAC collected since January 1, 2014, and allow the balance in Account 101 to remain unchanged. D.P.U. 19-120, at 189; D.P.U. 17-170, at 56; D.P.U. 12-25, at 112. The Company would continue to record CIAC as a credit against plant, but the CIAC would be booked to the new subaccount, with an offsetting credit to Account 271. D.P.U. 19-120, at 189; D.P.U. 17-170, at 56; D.P.U. 12-25, at 112. As part of this accounting treatment, the Company would add a new line to the plant detail pages of its Annual Return to the Department to record a debit for contributions received, thereby offsetting the credit to Account 271. D.P.U. 19-120, at 189; D.P.U. 17-170, at 57-62; D.P.U. 12-25, at 112. This accounting treatment would bring the Company's books into conformance with the USOA-Gas, while allowing the Company to continue to maintain its gas plant accounts net of contribution and ensuring that its depreciation calculations and all other downstream recordings are unaffected by the accounting change. D.P.U. 17-170, at 56; D.P.U. 12-25, at 112.

Based on our review of the CIAC accounting procedures accepted for other gas companies and the relevant provisions of 220 CMR 50.00, the Department finds that this alternative approach provides a reasonable method of accounting for the Company's CIAC. D.P.U. 19-120, at 193-195; D.P.U. 17-170, at 57-62; D.P.U. 12-25, at 112-116. The procedure properly provides a separate account for CIAC, supports the integrity of the Department's prescribed accounting system, ensures accounting transparency for ratemaking purposes, and is consistent with similar proposals approved by the Department. D.P.U. 19-120, at 195; D.P.U. 17-170, at 62; D.P.U. 12-25, at 115. Therefore, the Department directs the Company to implement the accounting method as described above to record CIAC.

Because the Company's accounting practice has been longstanding, it would be difficult to identify and locate all of the work orders recording CIAC, and some portion of the CIAC is associated with plant that has now been retired (Tr. 8, at 827). In recognition of the difficulty that would be associated with extracting CIAC balances from the Company's plant accounts and determining what portion was associated with plant that remains in service, the Department will not require the Company to adjust its plant accounts for all CIAC historically received by the Company. Instead, the Department directs the Company to debit its plant in service accounts by those CIAC received since January 1, 2015. The Company shall credit Account 271 by the sum of $134,450, plus all CIAC received since the end of the test year (see Exh. DPU 17-1, Att. at 2 (gas)). The Company shall distribute the $134,450 among the work orders listed in Exhibit DPU 17-1, Attachment (gas) and shall distribute all CIAC received since the end of the test year to the appropriate plant accounts. The Company is further directed to provide the Department with the related journal entries within 30 days of the date of this Order. Finally, the Department directs the Company to ensure that its booking of depreciation expense does not result in depreciation being taken on CIAC. Milford Water Company, D.P.U. 84-135, at 32-33 (1985); Dedham Water Company, D.P.U. 84-32, at 18-20 (1984); Hingham Water Company, D.P.U. 1590, at 22-23 (1983).

G. GSEP Investments – Gas Division

1. Introduction

In Fitchburg Gas and Electric Light Company, D.P.U. 14-130, at 126-127 (2015), the Department approved the Company's GSEP pursuant to G.L. c. 164, § 145.[66] In D.P.U. 19-131, the Department approved a settlement, where the cost recovery of GSEP investments placed in service from January 1, 2015 through December 31, 2018 were transferred into base distribution rates. D.P.U. 19-131, at 6, 15. Unitil has made eight filings seeking cost recovery through the

[66] The GSEP, which is authorized by statute, is designed to recover annually, on a reconciling basis, the revenue requirement (including a return on investment, property taxes, and depreciation on capital investments made after January 1, 2015) to replace mains, services, meter sets, and other ancillary facilities composed of non-cathodically protected steel, cast iron, and wrought iron. G.L. c. 164, § 145; D.P.U. 14-130, at 2-3; M.D.P.U. No. 250, § 6.10 (gas). The Department also determined that copper as well as Aldyl-A pipe installed prior to 1985 should be included as eligible infrastructure. Fitchburg Gas and Electric Light Company, D.P.U. 18-GSEP-01, at 36-37 (2019).

GSEP factors for GSEP-related investments placed in service from January 1, 2019 through December 31, 2022. Fitchburg Gas and Electric Light Company, D.P.U. 23-GREC-01 (2023) (reconciliation of 2022 projects); Fitchburg Gas and Electric Light Company, D.P.U. 22-GREC-01 (2022) (reconciliation of 2021 projects); Fitchburg Gas and Electric Light Company, D.P.U. 21-GSEP-01 (2022) (proposed 2022 projects); Fitchburg Gas and Electric Light Company, D.P.U. 21-GREC-01 (2021) (reconciliation of 2020 projects); Fitchburg Gas and Electric Light Company, D.P.U. 20-GSEP-01 (2021) (proposed 2021 projects); Fitchburg Gas and Electric Light Company, D.P.U. 20-GREC-01 (2020) (reconciliation of 2019 projects); Fitchburg Gas and Electric Light Company, D.P.U. 19-GSEP-01 (2020) (proposed 2020 projects); Fitchburg Gas and Electric Light Company, D.P.U. 18-GSEP-01 (2019) (proposed 2019 projects). In the instant case, Unitil proposes transferring the cost recovery of GSEP investments placed in service from January 1, 2019 through December 31, 2022 into base distribution rates (Exh. Unitil-CGDN-1, at 7-8 (gas)). To effectuate this transfer, the Company proposes that on the effective date of new base distribution rates (i.e., July 1, 2024) it will file new gas system enhancement adjustment factors ("GSEAFs") to recover the July 2024 through December 2024 revenue requirement associated with calendar year 2023 and 2024 vintage GSEP investments, as well as the GSEP reconciliation adjustment balance as of June 30, 2024 (Exh. Unitil-CGDN-1, at 9 (gas)).

In addition, the Company proposes to adjust rate base and depreciation expense to account for: (1) the additional accumulated depreciation amount of $444,877; (2) the reduction to ADIT of $9,377; and (3) the reduction in the excess ADIT of $542,735 associated with the proposed GSEP investment roll-in for the period December 31, 2022 to July 1, 2024 (Exhs. Unitil-CGDN-1, at 50, 53 (gas); Sch. RevReq-4-7 (Rev. 4) (gas)).

The Company asserts that it submitted in the annual GSEP-related filings documentation for GSEP investments placed in service from January 1, 2019 through December 31, 2022, and that the Department reviewed and approved such investments (Company Brief at 242-243, citing Exh. Unitil-KSTBCL-1, at 24 (gas)). No other party addressed this issue on brief.

2. Analysis and Findings

The Department previously determined that the Company's GSEP investments placed into service between January 1, 2019 and December 31, 2022 were prudently incurred and used and useful in providing service to ratepayers. D.P.U. 23-GREC-01, at 19-20; D.P.U. 22-GREC-01, at 22; D.P.U. 21-GREC-01, at 15; D.P.U. 20-GREC-01, at 18. Additionally, the Company's proposal to roll these investments into rate base is consistent with Department precedent. D.P.U. 20-120, at 158; D.P.U. 19-120, at 165; D.P.U. 17-170, at 40 n.25, 47-48. For these reasons, the Department allows the inclusion in the Company's rate base of GSEP investments placed into service between January 1, 2019 and December 31, 2022.

Finally, the Department has reviewed the Company's proposals to (1) recover through the GSEAF proposed to be effective July 1, 2024, the July 2024 through December 2024 revenue requirement associated with calendar year 2023 and 2024 vintage GSEP investments and the GSEP reconciliation adjustment balance as of June 30, 2024, and (2) adjust rate base and depreciation expense to account for the additional accumulated depreciation amount, the reduction to ADIT, and the reduction in excess ADIT associated with the proposed GSEP investment roll-in (Exhs. Unitil-CGDN-1, at 9, 50, 53 (gas); Sch. RevReq-4-7 (Rev. 4) (gas)).

The Department finds these proposals to be reasonable and appropriate to avoid double recovery of costs and consistent with the Company's GSEAF tariff, M.D.P.U. No. 250 (gas), and G.L. c. 164, § 145. Accordingly, the Department approves these proposals.

H. Conclusion

Based on our findings above, the Department finds that Unitil's electric and gas division plant additions were prudently incurred and that the resulting plant is used and useful in providing service to the Company's customers. The Department allows the Company's electric division rate base of $84,336,128 and the gas division rate base of $121,126,138 (Exhs. Sch. RevReq-4 (Rev. 4) (electric); Sch. RevReq-4 (Rev. 4) (Gas)).

VI. OPERATION AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Payroll

a. Introduction

When determining the reasonableness of a company's employee compensation expense, the Department reviews the company's overall employee compensation expense to ensure that its compensation decisions result in a minimization of unit-labor costs. D.P.U. 96-50 (Phase I) at 47; Cambridge Electric Light Company, D.P.U. 92-250, at 55 (1993). This approach recognizes that the different components of compensation (e.g., wages and benefits) are to some extent substitutes for each other and that different combinations of these components may be used to attract and retain employees. D.P.U. 92-250, at 55. In addition, the Department requires a company to demonstrate that its total unit-labor cost is minimized in a manner supported by its overall business strategies. D.P.U. 92-250, at 55. The individual components of a company's employment compensation package, however, will be appropriately left to the discretion of a company's management. D.P.U. 92-250, at 55-56.

A company is required to provide a comparative analysis of its compensation expenses to enable a determination of reasonableness by the Department. D.P.U. 96-50 (Phase I) at 47. The Department evaluates the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory and utilities in the region that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47; D.P.U. 92-250, at 56; Bay State Gas Company, D.P.U. 92-111, at 103 (1992); D.P.U. 92-78, at 25-26.

Unitil's employee compensation program provides for: (1) base pay; (2) incentive compensation; (3) vacation and holiday pay; (4) medical and dental insurance; (5) life and disability insurance; (6) matching contributions to a 401(k) savings plan; (7) pension and other post-retirement benefits; (8) wellness benefits; and (9) educational assistance (Exhs. Unitil-CGDN-1, at 23-31 (electric); Unitil-JFC-1, at 2 (electric); AG 1-40, Att. 2 (Rev.) (electric); DPU 39-9 (electric); Unitil-CGDN-1, at 25-29 (gas); Unitil-JFC-1, at 2 (gas); AG 1-40, Att. 2 (Rev.) (gas); DPU 33-9 (gas)).

b. Union Wage Increases

i. Introduction

During the test year, Unitil booked $1,168,113 in union payroll O&M expense to its electric division, and $1,265,878 to its gas division (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Unitil-WP 2.1 (Rev. 4) (electric); Sch. RevReq-3-8 (Rev. 4) (gas); Unitil-WP 1.1 (Rev. 4) (gas)). The Company proposes to increase union payroll expense by $86,327 for its electric division and

$96,722 for its gas division (see Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Sch. RevReq-3-8 (Rev. 4) (gas)).

The proposed adjustments to the test-year expense include a three percent annualized pay raise that took effect on June 1, 2022, a three percent pay raise that took effect on June 1, 2023, and a three percent pay raise for effect on June 1, 2024, in accordance with union contracts (Exhs. Unitil-CGDN-1, at 23-25 (electric); Sch. RevReq-3-5 (Rev. 4) (electric); Unitil-WP 2.6 (Rev. 4) (electric); Unitil-CGDN-1, at 20-22 (gas); Sch. RevReq-3-8 (Rev. 4) (gas); Unitil-WP 1.6 (Rev. 4) (gas); AG 1-42, Atts. 3-5).

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that the Department should disallow the proposed 2024 union wage increase because it would occur beyond the end of the historical test year and is speculative (Attorney General Brief at 65, citing Exh. AG-LKM-1, at 18).[67] In addition, the Attorney General objects to the inclusion of costs associated with mobile data systems (Attorney General Brief at 67). The Attorney General argues that the Company has not offered any evidence to demonstrate that mobile data systems charges have increased, or will increase, at the same rate as wages and salaries (Attorney General Brief at 67).

67 On brief, the Attorney General did not differentiate between union and non-union wage increases. Based on the exhibits cited on brief, the bulk of her positions are inapplicable with respect to the proposed union wage increases (see, e.g., Attorney General Brief at 65-66, citing Exhs. Unitil-Rev-Req-Rebuttal at 10).

(B) Company

The Company asserts that the Company's union wage increases are established periodically through the collective bargaining process (Company Brief at 185, citing Exhs. Unitil-JFC-1, at 9, 11; DPU 25-7 (electric); Company Brief at 156, citing Exh. DPU 22-3 (gas)). The Company maintains that union wages within the utility industry are increasing on average by three percent per year, and Unitil contends that this equates to its current annual wage increases in its collective bargaining agreements (Company Brief at 185, citing Exhs. AG 1-41; AG 1-42, Att. 3, at 49-55; AG 1-43; AG 4-3; RR-DPU-16 (electric); Company Brief at 156 (gas)).

With respect to mobile data system costs, the Company maintains that charges displayed in its supporting workpapers represent the service technicians' wages, and that these payroll expenses are charged to various general ledger accounts that are determined by the individual employee timecard entries based on the work performed (Company Brief at 206 (electric), citing Exhs. Unitil-WP 2.4 (electric); AG 4-5 (electric); Company Brief at 177 (gas), citing Exhs. Unitil-WP 1.4; AG 4-9 (gas)). Unitil asserts that, given that the mobile data system charges represent the technicians' wages, they are appropriate to include in the payroll expenses. Company Brief at 207 (electric)); Company Brief at 177 (gas)).

iii. Analysis and Findings

The Department's standard for union payroll adjustments requires that three conditions be met: (1) the proposed increase must take effect before the midpoint of the first twelve months after the date of the rate increase; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the Company must demonstrate that the proposed increase is reasonable. D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35; Western Massachusetts Electric Company, D.P.U. 86-280-A at 73-74 (1987).

In this proceeding, December 31, 2024, represents the midpoint of the rate year.[68] The Company's proposed union payroll adjustments include increases that have been granted or will be granted by June 1, 2024 (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Sch. RevReq-3-8 (Rev. 4) (gas); AG 1-42, Atts. 3-5). Because the increases occur prior to the midpoint of the rate year, we find that the Company meets the first condition. With respect to the second condition, the union payroll increases are based on signed collective bargaining agreements (Exh. AG 1-42, Atts. 3-5). Thus, the Department finds that the proposed increases are known and measurable.

The Department has found that reasonableness is determined by evaluating the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory and utilities in the region that compete for similarly skilled employees. D.P.U. 96-50 (Phase I) at 47-48; D.P.U. 92-250, at 56; D.P.U. 92-111, at 103; D.P.U. 92-78, at 25-26. Between 2013 and 2022, annual union wage increases were three percent (Exh. AG 1-41, Att.). The Company provided evidence of comparable wage increases provided by regional utilities (RR-DPU-16 & Atts.). Based on these considerations, the Department finds that the proposed union wage increases of three percent are reasonable.

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68 The rate year begins July 1, 2024, and ends June 30, 2025.

We determine that the Attorney General's arguments with respect to the mobile data system charges lack merit.[69] The mobile data system is used by the Company's service technicians to track their time and materials associated with billable and non-billable service calls (Exhs. DPU 6-16 & Att. (electric); AG 4-5 (electric); DPU 5-8 & Att. (gas); AG 4-9 (gas)). The record evidence demonstrates that Unitil included in its payroll expenses costs associated with service technicians' wages only, and the payroll expenses are charged to various general ledger accounts that are determined by the individual employee timecard entries based on the work performed (Exhs. AG 4-5 (electric); Unitil-WP 2.4 (Rev. 4) (electric); AG 4-9 (gas); Unitil-WP 1.4 (gas)). There is no evidence to suggest that these union employees are not covered by the unions' collective bargaining agreements and, as such, they should experience increases based on collective bargaining agreements on the same basis as other union members (Exhs. AG 4-5 (electric); AG 4-9 (gas)). Therefore, any disallowance based on the Attorney General's rationale would be inappropriate.

Based on the foregoing findings, the Department approves the Company's proposed union wage expense. Accordingly, the Department allows the Company's proposed increases of $86,327 for the electric division and $96,722 for the gas division.

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69 The Attorney General sought to deny $244,015 and $356,364 for the electric division and gas division, respectively, but did not itemize between union and non-union costs (Attorney General Brief at 67). Based on the record, the union costs are $188,136 and $248,386 for the electric division and gas division, respectively (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Unitil-WP 2.4 (electric); Sch. RevReq-3-8 (Rev. 4) (gas); Unitil-WP 1.4 (gas)).

c. Non-Union Wage Increases

i. Introduction

During the test year, Unitil booked $3,450,763 in non-union payroll O&M expense to its electric division, consisting of $358,381 in direct wages and salaries and incentive compensation, and $3,092,382 in allocated payroll from USC (Exh. Sch. RevReq-3-5 (Rev. 4) (electric)). During the test year, Unitil booked $2,772,000 in non-union payroll O&M expense to its gas division, consisting of $559,693 in direct wages and salaries and incentive compensation, and $2,212,306 in allocated payroll from USC (Exh. Sch. RevReq-3-8 (Rev. 4) (gas)).

Based on revisions made during the proceeding, the Company proposes to increase non-union payroll expense by $521,533 for the electric division to reflect: (1) $16,020, representing a non-union wage increase of 4.47 percent effective January 1, 2023; (2) $16,773, representing a non-union wage increase of 4.48 percent effective January 1, 2024; (3) $11,735, representing a non-union wage increase of 3.00 percent effective January 1, 2025; (4) $177,503, representing a USC non-union wage increase of 5.74 percent effective January 1, 2023; (5) $195,539, representing a USC non-union wage increase of 5.98 percent effective January 1, 2024; and (6) $103,963, representing a USC non-union wage increase of 3.00 percent effective January 1, 2025 (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); AG 4-11 (Rev.) (electric); AG 4-12 (Rev.) (electric); Unitil-1 (2/1/24) (electric)).

For the gas division, the Company proposes to increase non-union payroll expense by $424,900 to reflect: (1) $32,798, representing a non-union wage increase of 5.86 percent effective January 1, 2023; (2) $32,113, representing a non-union wage increase of 5.42 percent effective January 1, 2024; (3) $18,738, representing a non-union wage increase of 3.00 percent effective January 1, 2025; (4) $126,986, representing a USC non-union wage increase of 5.74 percent effective January 1, 2023; (5) $139,890, representing a USC non-union wage increase of 5.98 percent effective January 1, 2024; and (6) $74,375, representing a USC non-union wage increase of 3.00 percent effective January 1, 2025 (Exhs. Sch. RevReq-3-8 (Rev. 4) (gas); AG 4-15 (Rev.) (gas); AG 4-16 (Rev.) (gas); Unitil-1 (2-1-24) (gas)).

The non-union wage increases were determined based on salary surveys and a compensation study performed by Willis Towers Watson in 2019 on behalf of the Unitil Corporation companies, including the Massachusetts operating divisions (Exhs. Unitil-JFC-1, at 7-8 (electric); DPU 6-9, Att. 2 (electric); DPU 31-6 & Atts. (electric); Unitil-JFC-1, at 7-8 (gas); DPU 5-1, Att. 2 (gas); DPU 26-5 & Atts. (gas)).

ii. Positions of the Parties

(A) Attorney General

The Attorney General argues that the Department should disallow the proposed 2024 and 2025 non-union wage increases (Attorney General Brief at 65). The Attorney General disputes the Company's assertion that the Department allows non-union salary increases that are scheduled to become effective no more than six months after the date of the Department's Order (Attorney General Brief at 66, citing Exh. Unitil-Rev-Req-Rebuttal at 10). Specifically, the Attorney General asserts that post-test-year adjustments are not appropriate under cost-of-service ratemaking (Attorney General Brief at 66). The Attorney General contends that such post-test-year increases are allowed only for companies operating under a PBR plan, which she maintains is inapplicable to Unitil (Attorney General Brief at 66).

The Attorney General also claims that the Company's adjustment does not consider any change in the number of employees or employee mix that may occur during 2024 (Attorney General Brief at 65, citing Exh. AG-KLM-1, at 18). The Attorney General argues that the compensation review performed by Willis Towers Watson does not capture details about the employee mix because it does not evaluate compensation at the individual level (Attorney General Brief at 66). According to the Attorney General, when new employees assume vacated positions, they do not automatically receive the same salary as the previous employees in the same positions (Attorney General Brief at 66; Attorney General Reply Brief at 18). As a result, the Attorney General argues that the Company's salary change is speculative and inflated (Attorney General Reply Brief at 18).

In addition, the Attorney General objects to the inclusion of costs associated with mobile data systems (Attorney General Brief at 67). The Attorney General argues that the Company has not offered any evidence to demonstrate that mobile data systems charges have increased, or will increase, at the same rate as wages and salaries (Attorney General Brief at 67).

(B) Company

The Company claims that the Unitil Companies' policy is to compensate employees at (or near) the median of the marketplace for base pay and total cash compensation (Company Brief at 178 (electric), citing Exh. Unitil-JFC-1, at 3 (electric); Company Brief at 148 (gas), citing Exh. Unitil-JFC-1, at 3 (gas); Company Reply Brief at 58). Unitil maintains that the Department's standard for post-test-year payroll adjustments is well-established, and that the Company has met such standards (Company Brief at 204 (electric), citing Exh. Unitil-RevReq-Rebuttal at 10 (electric); Company Brief at 174 (gas), citing

Exh. Unitil-RevReq-Rebuttal at 9 (gas); Company Reply Brief at 57). The Company further argues that the established precedent is applicable regardless of whether a company is operating under a PBR plan (Company Brief at 204 (electric), citing Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 152-153 (2016); D.P.U. 14-150, at 142-144; Bay State Gas Company, D.P.U. 13-75, at 150-154 (2014); D.P.U. 12-25, at 151-154; Boston Gas Company, Essex Gas Company, and Colonial Gas Company, D.P.U. 10-55, at 243-245 (2010); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 128-132 (2009); Bay State Gas Company, D.P.U. 09-30, at 188-189 (2009)); Company Brief at 174-175 (gas)).

The Company additionally argues that Unitil has demonstrated that its post-test-year wage increases are appropriate, regardless of the mix of employees at the time of the increase, based on the way the Company determines the annual salary budget and individual employees' annual increase (Company Brief at 205 (electric); Company Brief at 175 (gas)). According to the Company, an analysis regarding the employee mix and its impact on future wage increases is not required under the Department's standard for non-union wage increases (Company Reply Brief at 58). Moreover, Unitil contends that the annual wage increases are employee-specific, and that the Company does not simply apply the annual percentage increase to each employee regardless of tenure (Company Brief at 206 (electric); Company Brief at 175 (gas)). Unitil also contends that it uses WorldAtWork salary data to inform any changes when calculating the non-union annual salary budget (Company Brief at 205 (electric), citing Exh. DPU 31-6, Att. 1, at 45 (electric); RR-DPU-45). The Company claims such steps are necessary to ensure that the Company and USC can attract and retain skilled individuals to undertake work that assists in providing customers with safe and reliable service at a reasonable cost (Company Brief at 181 (electric); Company Brief at 151 (gas)). Finally, Unitil asserts that, given that the mobile data system charges represent a portion of the technicians' wages, they are appropriate to include in the payroll expenses (Company Brief at 207 (electric); Company Brief at 177 (gas)).

iii. Analysis and Findings

To recover an increase in non-union wages, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is a historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983). In addition, only non-union salary increases that are scheduled to become effective no later than six months after the date of the Order may be included in rates. Boston Edison Company, D.P.U. 85-266-A/271-A at 107 (1986).

The Company provided confirmation of the increase in the form of a management commitment letter stating that a three percent payroll increase for non-union employees will be granted (Exhs. Unitil-1 (2/1/24) (electric); Unitil-1 (2/1/24) (gas)). Thus, the Company has met the first requirement by demonstrating that there is an express commitment by management.

The Company must next demonstrate that there is a historical correlation between union and non-union raises. Between 2013 and 2022, the Company provided annual wage increases for both union and non-union employees (Exh. AG 1-41, Att.). Those annual union wage increases were three percent and non-union increases were between three and 4.5 percent (Exh. AG 1-41, Att.). Accordingly, the Department finds that the Company has shown a sufficient correlation exists between union and non-union wage increases (Exh. AG 1-41, Att.). Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); D.P.U. 87-59-A at 18.

With respect to the reasonableness of the non-union wage increase, the Company's policy is to compensate employees at or near the median of the marketplace for base pay and total cash compensation (Exhs. Unitil-JFC-1, at 3 (electric); DPU 6-9, Att. 2, at 7 (electric); Unitil-JFC-1, at 3 (gas); DPU 5-1, Att. 2, at 7 (gas)).[70] The Willis Towers Watson study concluded that the Company's pay structure was very close to market median for most positions and paygrades, but that some positions and pay grades were below market median (Exhs. Unitil-JFC-1, at 8 (electric); DPU 6-9, Att. 2 (electric); Unitil-JFC-1, at 8 (gas); DPU 5-1, Att. 2 (gas)). Willis Towers Watson made specific recommendations for changes to these pay levels (Exhs. Unitil-JFC-1, at 8 (electric); DPU 6-9, Att. 2 (electric); Unitil-JFC-1, at 8 (gas); DPU 5-1, Att. 2 (gas)). In 2020, the Company implemented the Willis Towers Watson recommendations and adjusted the pay ranges for positions that were below the market median (Exhs. Unitil-JFC-1, at 8 (electric); Unitil-JFC-1, at 8 (gas)).

In 2023 and 2024, the Company granted raises ranging from 4.47 percent to 5.98 percent (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Sch. RevReq-3-8 (Rev. 4) (gas)).[71] The Company

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70 The Department analyzes the reasonableness of the executive compensation in Section VI.A.1.d. below.

71 For the electric division, the Unitil non-union raises are 4.47 percent and 4.48 percent effective January 1, 2023, and January 1, 2024, respectively (Exh. Sch. RevReq-3-5 (Rev. 4) (electric)). For the gas division, the Unitil non-union raises are 5.86 percent and 5.42 percent effective January 1, 2023, and January 1, 2024, respectively (Exh. Sch. RevReq-3-8 (Rev. 4) (gas)). For both the electric division and gas division, the USC increases are 5.74 percent and 5.98 percent effective January 1, 2023, and January 1, 2024, respectively (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric);

states that such increases are informed by WorldAtWork surveys and employee-specific increases determined by the employee's wage relative to the median and the employee's tenure at Unitil (RR-DPU-45). The record shows that WorldAtWork's 2022/2023 and 2023/2024 salary budget surveys estimated the 2023 and 2024 increases to be four percent (Exhs. DPU 31-6, Att. 1, at 32, 35 (electric); DPU 26-5, Att. 1, at 32, 35 (gas)). Further the 2023/2024 budget increases in the WorldAtWork surveys incorporate additional increases, such as merit increases (Exhs. DPU 31-6, Att. 1, at 28, Figures 1 and 2 (electric); DPU 26-5, Att. 1, at 28, Figures 1, 2 (gas)). The Department finds, in this instance, that increasing the non-union wages beyond the recommended WorldAtWork amounts is unreasonable. Basing the annual increases on the four percent estimated by the WorldAtWork surveys results in a revenue requirement reduction of $127,980 associated with 2023 and 2024 non-union wage increases, or $121,450 net of internal transmission, for the electric division and $108,760 associated with 2023 and 2024 company wage increases for the gas division.

The Company's proposed non-union payroll adjustments include increases that have been granted or will be granted through January 2024, with one exception (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Sch. RevReq-3-8 (Rev. 4) (gas)). The Company proposes, for its electric and gas divisions, a USC non-union wage increase of three percent effective January 1, 2025 (Exhs. Unitil-CGDN-1, at 24-25 (electric); Sch. RevReq-3-5 (Rev. 4) (electric); Unitil-CGDN-1, at 21-22 (gas); Sch. RevReq-3-8 (Rev. 4) (gas)). Although the six-month mark from the date of

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Sch. RevReq-3-8 (Rev. 4) (gas)). For both the electric division and gas division, the Unitil and USC increases effective January 1, 2025, are 3.0 percent (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Sch. RevReq-3-8 (Rev. 4) (gas)).

this Order is December 30, 2024, and the salary increase is effective January 1, 2025, we find the time difference to be de minimis and not critical to the Company's proposal.

The Department is not persuaded by the Attorney General's argument that post-test-year wage increases are dependent on whether the Company operates under a PBR plan. The Department's well-established standard allows for post-test-year non-union wage increases so long as the aforementioned conditions are met, regardless of whether a utility operates under a PBR. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 101-103 (2014 test year, allowing non-union wage increases effective in 2015 and 2016); D.P.U. 11-01/D.P.U. 11-02, at 177-179 (2009 test year, allowing union wage increases effective in 2010 and 2011).

Further, contrary to the Attorney General's assertions, the Department has not previously required that non-union wage increases account for employee mix.[72] We also determine that the Attorney General's arguments with respect to the mobile data system charges lack merit.[73] As outlined in Section VI.A.1.b.iii. above, the record evidence demonstrates that these charges represent salaries only and, as such, these employees will experience increases on the same basis as other non-union employees (Exhs. AG 4-5 (electric); AG 4-9 (gas)).

Based on the above, we find that Unitil has demonstrated that: (1) there is an express commitment to grant the increases; (2) there is a historical correlation between union and

[72] The Attorney General did not cite to any Department precedent in making her assertions.

[73] The Attorney General sought to deny \$244,015 and \$356,364 for the electric division and gas division, respectively, but did not itemize between union and non-union costs (Attorney General Brief at 67). Based on the record, the non-union costs are \$55,879 and \$107,978 for the electric division and gas division, respectively (Exhs. Sch. RevReq-3-5 (Rev. 4) (electric); Unitil-WP 2.4 (electric); Sch. RevReq-3-8 (Rev. 4) (gas); Unitil-WP 1.4 (gas)).

non-union increases; and (3) the 2025 non-union pay raises will occur within an appropriate timeframe after issuance of this Order. At the same time, the Company has failed to provide evidence that a portion of the wage increases are reasonable. Based on the foregoing, the Department reduces the Company's cost of service by $121,450 (net of internal transmission) for the electric division non-union payroll expense and by $108,760 for the gas division non-union payroll expense.

d. Executive Compensation

i. Introduction

As noted above, in 2019 Willis Towers Watson performed a compensation study on the Company's behalf (Exhs. DPU 6-9, Atts. 1-4 (electric); DPU 5-1, Atts. 1-4 (gas)). The compensation study separately reviewed non-union staff compensation, executive compensation, benefits valuation, and board of directors' compensation (Exhs. DPU 6-9, Atts. 1-4 (electric); DPU 5-1, Atts. 1-4(gas)). At that time, there were 23 executives who held positions at one or more of the following entities: Unitil Corporation, USC, and the Company (Exhs. DPU 6-9, Att. 1, at 3 (electric); DPU 5-1, Att. 1, at 3 (gas)). Compensation for some of these 23 executives was allocated from USC to the Company, as well as other affiliates, using a three-factor allocator derived from ratios of data for revenue, customers, and utility plant assets (Exh. AG 1-28, Att. 1, at 30). The amount billed to and incurred by Unitil was further allocated among the Company's operating divisions using a labor allocator, with 51.30 percent and 48.70 percent apportioned to the electric division and gas division, respectively (Exhs. Unitil-WP 4.2 (Rev. 4) (electric); DPU 10-12, Att. 2 (electric); Unitil-WP 3.2 (Rev. 4) (gas); DPU 10-11, Att. 2 (gas)).[74]

ii. Positions of the Parties

(A) Company

The Company argues that it has demonstrated that its executive salaries are reasonable and consistent with the Department's standard (Company Brief at 183 (electric); Company Brief at 153 (gas)). Further, the Company contends that the level at which it offers executive compensation (i.e., base salary, annual incentive compensation, long-term equity compensation) is consistent with the market, as it is 95 percent of the market median on average (Company Brief at 184 (electric), citing Exh. DPU 6-9, Att. 1, at 7 (electric); Company Brief at 154 (gas), citing Exh. DPU 5-1, Att. 1, at 7 (gas)). Finally, the Company asserts that it has carefully and deliberately constructed its executive compensation package, consistent with industry norms, to ensure that it has access to executives who will advance the Company's overall corporate mission to provide customers with high-quality, safe, and reliable service at reasonable rates and that it has the means to retain these executives (Company Brief at 184 (electric), citing Exhs. DPU 24-13 (electric); DPU 42-12 (electric); RR-DPU-46; Company Brief at 154-155

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74 The Company notes that the number of executives increased from 2019 through the test year, as several positions were added to ensure continued compliance with state and federal laws and regulations, incorporate rapidly advancing technology, provide uninterrupted safe and reliable service, and guarantee a continuity of leadership through succession in key roles in the future (RR-DPU-46).

(gas), citing Exhs. DPU 20-13 (gas); DPU 34-18 (gas); RR-DPU-46). No intervenor addressed this issue on brief.[75]

iii. Analysis and Findings

The Department analyzes executive compensation as part of its evaluation of non-union wages. D.P.U. 01-56, at 55. Where questions are raised regarding the reasonableness of the executive compensation, the Department provides additional analysis with respect to reasonableness. D.P.U. 01-56, at 56-57. The Willis Towers Watson compensation study used: (1) published compensation surveys focused on comparably sized organizations in the utility sector where the data were size-adjusted based on Unitil's current revenues; and (2) 2019 proxy statements of 13 comparably sized public organizations in the utility sector (Exhs. DPU 6-9, Att. 1, at 4-5 (electric); DPU 5-1, Att. 1, at 4-5 (gas)). Regarding the size-adjusted data, the Company's chief executive officer's total target direct compensation was 86 percent of the market median, while the chief financial officer's total target direct compensation was 78 percent of the market median and 103 percent of the 25th percentile (Exhs. DPU 6-9, Att. 1, at 21 (electric); DPU 5-1, Att. 1, at 21 (gas)). When compared to companies of a similar size to Unitil, the chief executive officer's compensation was 63 percent of the 25th percentile and the chief financial officer's compensation was 76 percent of the 25th percentile (Exhs. DPU 6-9, Att. 1, at 21 (electric); DPU 5-1, Att. 1, at 21 (gas)). While the compensation of the chief executive officer and chief financial officer, respectively, is in line with the Company's policy of

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75 Although no intervenor addressed this issue on brief, numerous commenters raised questions about executive compensation during the public comment period (see, e.g., Tr. A at 45, 58).

compensating employees at the median of the marketplace, to evaluate the reasonableness of Unitil's executive compensation, it is necessary to review a broader range of the Company's executives. D.P.U. 11-01/D.P.U. 11-02, at 184. As noted above, the compensation study provides data on the Company's top 23 executives and compares their compensation with those of comparable organizations (Exhs. DPU 6-9, Att. 1, at 2-4 (electric); DPU 5-1, Att. 1, at 2-4 (gas)). Overall, the Company's target total direct compensation was 104 percent of the 25th percentile and 84 percent of the market median (Exhs. DPU 6-9, Att. 1, at 21-22 (electric); DPU 5-1, Att. 1, at 21-22 (gas)). Regarding actual total direct compensation, Unitil's executives as a group were compensated at 95 percent of the market median (Exhs. DPU 6-9, Att. 1, at 23-24 (electric); DPU 5-1, Att. 1, at 23-24 (gas)). Moreover, the record shows that salaries have increased from 2019 through the test year by an annualized 3.9 percent,[76] while overall compensation and benefits (including health and wellness and retirement benefits) increased by an average of 3.0 percent[77] annually (Exh. AG 1-36, Att.). Based on these considerations, we are satisfied that the overall compensation levels paid to Unitil executives from 2019 through the test year do not support a finding of excessive executive compensation.

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76 The top 23 employees made a total of $4,793,921 in 2019 and $5,373,190 in 2022, which equates to an annualized 3.9 percent increase (Exh. AG 1-36, Att.).

77 Including incentive compensation, restricted stock, health and wellness benefits, and retirement benefits, the top 23 employees received $9,138,493 in benefits in 2019 and $9,998,962 in 2022, corresponding to an overall annual increase of three percent (Exh. AG 1-36, Att.).

2. Incentive Compensation

a. Introduction

The Company offers three incentive compensation programs. The first, the Unitil Corporation Incentive Plan ("Incentive Plan"), is open to all employees of Unitil except: (1) those named by the board of directors to participate in the Unitil Corporation Management Incentive Plan ("Management Plan"); and (2) union members, unless participation is allowed under the terms of a collective bargaining agreement (Exhs. Unitil-JFC-1, at 4 (electric); DPU 31-3, Att. 1 (electric); Unitil-JFC-1, at 4 (gas); DPU 26-2, Att. 1 (gas)). The second program is the Management Plan, for which all executives, including named executive officers, are eligible to participate (Exhs. Unitil-JFC-1, at 4 (electric); AG 1-2, Att. 5-5, at 60 (electric); DPU 31-3, Att. 2 (electric); Unitil-JFC-1, at 4 (gas); DPU 26-2, Att. 2 (gas)). The third program is the Restricted Stock Plan, which is available to all non-union employees, although restricted stock grants are typically awarded to employees in key management positions (Exhs. Unitil-JFC-1, at 4 (electric); AG 1-2, Att. 5-5, at 61; DPU 31-3, Att. 3 (electric); Unitil-JFC-1, at 4 (gas); DPU 26-2, Att. 3 (gas); DPU 26-3 (gas)).

Under the Incentive Plan, employees of Unitil Corporation and its subsidiaries, including the Company, are eligible for an annual target incentive award equal to a predetermined percentage of their individual base salaries, net of any adjustments associated with their 401(k) plans (Exhs. DPU 31-3, Att. 1, at 1 (electric); DPU 26-2, Att. 1, at 1 (gas)). Prior to, or soon after the start of each performance period, a compensation committee establishes performance objectives and weights for the upcoming year based on recommendations made by

Unitil Corporation's chief executive officer (Exhs. DPU 31-3, Att. 1, at 1 (electric); DPU 26-2, Att. 1, at 1 (gas)).

Similarly, under the Management Plan, members are eligible for an annual target incentive award equal to a predetermined percentage of their individual base salaries, net of any adjustments associated with their 401(k) plans (Exhs. DPU 31-3, Att. 2, at 1 (electric); DPU 26-2, Att. 2, at 1 (gas); AG 1-2, Att. 5-5, at 60). A compensation committee establishes the individual targets (Exhs. DPU 31-3, Att. 2, at 1 (electric); DPU 23-2, Att. 1, at 1 (gas); AG 1-2, Att. 5-5, at 60). Finally, under the Restricted Stock Plan, the compensation committee may grant shares to participants in such amounts as the committee shall determine and subject to any restrictions the committee may deem appropriate (Exhs. DPU 31-3, Att. 3, at 7 (electric); DPU 26-2, Att. 3, at 7 (gas)).

The performance goals for the three incentive plans are: (1) electric reliability based on the system average interruption duration index ("SAIDI"); (2) gas safety (i.e., response rate to odor calls); (3) customer satisfaction; (4) O&M cost-per-customer; and (5) earnings per share ("EPS") (Exhs. Unitil-JFC-1, at 5 (electric); DPU 31-8 (electric); Unitil-JFC-1, at 5 (gas); DPU 26-7 (gas)). The performance objectives are evaluated based on three levels of achievement upon which different payout levels are established: (1) a threshold level for which 50 percent of the target payout is made; (2) a target level for which 100 percent payout is made; and (3) a maximum level for which 150 percent of the target incentive payment is made (Exhs. DPU 31-3, Att. 1, at 2 (electric); DPU 26-2, Att. 1, at 2 (gas)). During the test year, the Company paid out 124 percent of target compensation levels (Exhs. DPU 39-4, Att. 1, at 2 (electric); DPU 53-3 & Att. (electric); DPU 53-5 & Att. (electric); DPU 33-4, Att. 1, at 2 (gas);

DPU 42-7 & Att. (gas); DPU 42-9 & Att. (gas)). The test-year cost of service, however, was adjusted to reduce incentive compensation to a target level of payout so that only the target level of performance is included in the revenue requirement, and any compensation paid in excess of target levels is borne entirely by shareholders (Exhs. Unitil-JFC-1, at 5 (electric); Unitil-WP 2.2 (Rev. 4) (electric); Unitil-WP 2.7 (Rev. 4) (electric); DPU 6-19, Att. (Rev.) (electric); DPU 53-3 & Atts. (electric); DPU 53-5 & & Atts (electric); Unitil-WP 1.2 (Rev. 4) (gas); Unitil-JFC-1, at 5 (gas); Unitil-WP 1.7 (Rev. 4) (gas); DPU 5-11, Att. (Rev.) (gas); DPU 42-7 & Atts. (gas); DPU 42-9 (gas)). Finally, the amount was reduced by an additional 40 percent to exclude costs associated with financial incentives (Exhs. Unitil-JFC-1, at 6 (electric); Unitil-CGDN-1, at 24-27 (electric); Unitil-WP 2.2 (Rev. 4) (electric); Unitil-WP 2.7 (Rev. 4) (electric); DPU 6-19, Att. 1 (Rev.) (electric); Unitil-JFC-1, at 5 (gas); Unitil-CGDN-1, at 21-22, 24 (gas); Unitil-WP 1.2 (Rev. 4) (gas); Unitil-WP 1.7 (Rev. 4) (gas); DPU 5-11, Att. 1 (Rev.) (gas)).

As a result of these adjustments, the Company proposes to include in its cost of service a total of $281,488 in incentive compensation ($11,431 in direct company expense and $270,057 in allocations from USC) for the electric division and $189,830 in incentive compensation ($9,391 in direct company expense and $180,440 in allocations from USC) for the gas division (Exhs. Unitil-WP 2.7 (Rev. 4) (electric); Unitil-WP 1.7 (Rev. 4) (gas); Tr. 4, at 368-371).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's Restricted Stock Plan expense should be removed from the cost of service (Attorney General Brief at 68-69; Attorney General Brief at 14-17). The Attorney General asserts that the Company's Restricted Stock Plan is typically paid only to employees in key management positions and is distinct from the other incentive plans because the full award is tied to earning goals (Attorney General Brief at 68, citing Exh. AG-KLM-1, at 19). In particular, the Attorney General contends that the performance objectives of the Restricted Stock Plan are not job performance standards designed to encourage good employee performance but rather are designed to align the interests of employees and shareholders and measure employee performance by financial earnings alone (Attorney General Reply Brief at 17).

The Attorney General argues that the Department has "flatly rejected" the inclusion of financial components in evaluating the Incentive Plan and Management Plan and should do the same with the Restricted Stock Plan (Attorney General Brief at 68-69, citing D.P.U. 15-80/D.P.U. 15-81, at 117; D.P.U. 11-01/D.P.U. 11-02, at 193-194). The Attorney General further asserts that by including the entire compensation paid under the Restricted Stock Plan in the cost of service, the Company erroneously increased the electric division's operating expense by $271,591 and the gas division's operating expense by $223,111 (Attorney General Brief at 69, citing Exh. AG-LMK-1, at 20; Attorney General Reply Brief at 14).

ii. Company

Unitil asserts that its incentive compensation program is a fundamental component of the Company's overall compensation package, which in the aggregate is consistent with market levels and designed to attract and retain the sort of highly skilled employees that enable the Company to meet its service obligations for the direct benefit of its customers (Company Brief at 186 (electric); Company Brief at 157 (gas)). The Company argues that each of its incentive plans is consistent with the Department's standard for inclusion of the relevant costs in the revenue requirement (Company Brief at 189 (electric); Company Brief at 159 (gas)). Further, the Company maintains that, consistent with Department precedent, it has removed from its cost of service the portion of incentive compensation tied to EPS, and it has adjusted the revenue requirement so that only the target level of performance is included for recovery (Company Brief at 188 (electric); Company Brief at 158 (gas)).

Regarding the Restricted Stock Plan, the Company contends that the weight given to EPS under the plan (i.e., 40 percent) shows that this metric acts as a threshold component, and that failure to achieve the EPS metric would likely result in the compensation committee determining not to fund the incentive pool or, at the very least, reducing funding significantly (Company Brief at 191 (electric), citing Exh. AG 4-9 (electric); Company Brief at 161 (gas), citing Exh. AG 4-13 (gas)). Further the Company submits that job performance standards designed to encourage good employee performance (e.g., safety, reliability, customer satisfaction goals) are used as the basis for determining individual incentive compensation awards (Company Brief at 190 (electric); Company Brief at 160-161 (gas); Company Reply Brief at 55-57). Thus, the Company asserts that it has met the Department's standard for inclusion of these costs in the revenue requirement (Company Brief at 190 (electric); Company Brief at 160-161 (gas)). Unitil asserts, however, that if the Department accepts the Attorney General's recommendation, the disallowance should be modified (Company Reply Brief at 57). Specifically, the Company contends that because the EPS component accounted for 40 percent of the performance metrics under the Restricted Stock Plan, and the Plan's participants' awards are determined based on their performance under all of the metrics, the disallowance would total $113,615 for the electric division and $79,994 for the gas division, not the $271,591 and $223,111, respectively, as calculated by the Attorney General (Company Reply Brief at 57, citing Exhs. AG 4-9, Att. 1 (electric); AG 4-10, Att. 1 (electric); AG 4-13, Att. 1 (gas); AG 4-14, Att. 1 (gas)).

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if: (1) the expenses are reasonable in amount; and (2) the incentive plans are reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; D.P.U. 89-194/195, at 34. For an incentive plan to be reasonable in design, it must both encourage good employee performance and result in benefits to ratepayers. D.P.U. 93-60, at 99.

The Department first determines whether Unitil's Incentive Plan, Management Plan, and Restricted Stock Plan are reasonable in design. During the test year, a portion of the Company's Incentive Plan, Management Plan and Restricted Stock Plan expenses were tied to meeting an EPS metric (Exhs. DPU 31-3, Att. 3, at 10 (electric); DPU 31-8 (electric); AG 4-9 & Att. 1 (electric); AG 4-10 & Att. 1 (electric); DPU 26-2, Att. 3, at 10 (gas); DPU 26-7 (gas); AG 4-13 & Att. 1 (gas); AG 4-14 & Att. 1 (gas)).

The purpose of the Company's Incentive Plan and Management Plan is to provide employees of Unitil Corporation and its subsidiaries with incentives related to the performance of the corporation and thereby to motivate them to maximize their efforts on the corporation's behalf (Exhs. DPU 31-3, Atts. 1-2, at 1 (electric); DPU 26-2, Atts. 1-2, at 1 (gas)). The objectives of the Restricted Stock Plan, however, are, in part, to optimize the profitability and growth of Unitil Corporation through incentives that are consistent with the corporation's goals and that link personal interests of the participants to those of the corporation's shareholders

(Exhs. DPU 31-3, Att. 3, at 2 (electric); DPU 26-2, Att. 3, at 2 (gas); AG 8-5, Att. 1). The record shows that the three performance plans are tied, in part, to achieving performance metrics (Exhs. DPU 31-3, Atts. 1-3 (electric); DPU 31-8 (electric); AG 4-9, Atts. 1, 3 (electric); AG 4-10, Att. 1 (electric); DPU 26-2, Atts. 1-3 (gas); DPU 26-7 (gas); AG 4-13, Atts. 1, 3 (gas); AG 4-14, Att. 1 (gas)).

For the three plans, the incentive compensation budgets are prepared at the beginning of each fiscal year based on the number of employees participating in the relevant compensation plan and the opportunities for the employees in the plan to achieve specific performance metrics set by a compensation committee (Exhs. Unitil-JFC-1, at 4 (electric); DPU 31-3, Atts. 1-2, at 1 (electric); Unitil-JFC-1, at 4 (gas); DPU 26-2, Atts. 1-2, at 1 (gas)). The compensation committee establishes performance objectives, assigns a weight to each objective, and determines performance standards (Exhs. Unitil-JFC-1, at 4 (electric); DPU 31-3, Atts. 1-2, at 1-2; Att. 3, at 1, 10 (electric); Unitil-JFC-1, at 4 (gas); DPU 26-2, Atts. 1-2, at 1-2; Att. 3, at 3, 10 (gas)). The performance target levels are based on past performance with an eye on continuous improvement, or on industry standards for performance (Exhs. Unitil-JFC-1, at 4 (electric); Unitil-JFC-1, at 4 (gas)). As noted above, the current performance objectives in the plans are: (1) electric reliability based on SAIDI; (2) gas safety; (3) customer satisfaction; (4) O&M cost-per-customer; and (5) EPS (Exhs. Unitil-JFC-1, at 5 (electric); DPU 31-8 (electric); Unitil-JFC-1, at 4 (gas); DPU 26-7 (gas)). During the year, the compensation committee is updated on the Company's performance against the performance metrics (Exh. Unitil-JFC-1, at 5 (electric); Unitil-JFC-1, at 4 (gas)). The Company noted that decisions as to how much incentive compensation will be paid out on an annual basis is solely up to the discretion of the compensation committee, but its decisions are informed by the Company's performance against the annual metrics (Exhs. Unitil-JFC-1, at 5 (electric); DPU 31-3, Atts. 1-2, at 2-3; Att. 3, at 5-6 (electric); Unitil-JFC-1, at 5 (gas); DPU 26-2, Atts. 1-2, at 2-3; Att. 3, at 5-6 (gas)). The amount of the incentive award earned by each employee participating in the plan depends on the degree of achievement of the performance metrics and the percentage weighting assigned to the metrics (Exh. DPU 31-3, Att. 1 (electric); DPU 26-2, Att. 1 (gas)).

The Department has articulated its expectations on the use of financial targets in incentive compensation plans and the burden required to justify the recovery of such costs in rates. D.P.U. 13-90, at 82-83; D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. Specifically, where companies seek to include financial goals as a component of incentive compensation design, the Department expects to see the attainment of such goals as a threshold component, with job performance standards designed to encourage good employee performance (e.g., safety, reliability, customer satisfaction goals) used as the basis for determining individual incentive compensation awards. D.P.U. 13-90, at 82-83; D.P.U. 11-01/D.P.U. 11-02, at 192-193; D.P.U. 10-70, at 105-106; D.P.U. 10-55, at 253-254. Companies that nonetheless wish to maintain financial metrics as a component of the formula used to determine individual incentive compensation must be prepared to demonstrate direct ratepayer benefit from the attainment of these goals or risk disallowance of the related incentive compensation costs. D.P.U. 13-90, at 83; D.P.U. 11-01/D.P.U. 11-02, at 193; D.P.U. 10-70, at 106; D.P.U. 10-55, at 253-254.

Consistent with Department precedent and the treatment of incentive compensation in the Company's previous adjudicated rate cases, the Department finds that Unitil has appropriately removed the EPS components of its Incentive Plan and Management Plan (Exhs. Unitil-JFC-1, at 6 (electric); Unitil-CGDN-1, at 24-27 (electric); Unitil-WP 2.2 (Rev. 4) (electric); Unitil-WP 2.7 (Rev. 4) (electric); DPU 6-19, Att. 1 (Rev.) (electric); Unitil-JFC-1, at 5 (gas); Unitil-CGDN-1, at 21-22, 24 (gas); Unitil-WP 1.2 (Rev. 4) (gas); Unitil-WP 1.7 (Rev. 4) (gas); DPU 5-11, Att. 1 (Rev.) (gas)). D.P.U. 15-80/D.P.U. 15-81, at 116-117; D.P.U. 13-90, at 83-84; D.P.U. 11-01/D.P.U. 11-02, at 193. The remaining performance objectives of electric reliability based on SAIDI, gas safety, customer satisfaction, and O&M cost-per-customer are reasonably designed to encourage good employee performance and provide direct ratepayer benefits (Exhs. Unitil-JFC-1, at 5 (electric); DPU 31-8 (electric); Unitil-JFC-1, at 5 (gas); DPU 26-7 (gas)). Based on these considerations and our review of the structure and application of the Incentive Plan and Management Plan, we find these plans to be reasonable in design.

While the Company has appropriately removed the EPS components of its Incentive Plan and Management Plan, the same cannot be said for the Restricted Stock Plan. Further, the Department does not agree with the Company's arguments that the entire amount should be included in the cost of service. As the Restricted Stock Plan is a component of Unitil's incentive compensation and calculated using the same performance standards, the Department finds it appropriate to treat the restricted stock expense in a similar manner (Exhs. AG 4-9, Att. 1 (electric); AG 4-10, Att. 1 (electric); AG 4-13, Att. 1 (gas); AG 4-14, Att. 1 (gas)). As a result, an adjustment reflecting the removal of the EPS amount from the cost of service must be made. Based on the above analysis, we remove from the Company's proposed cost of service the portion of incentive compensation tied to financial metrics (i.e., 40 percent) for the Restricted

Stock Plan, resulting a cost-of-service reduction of $113,615 for the electric division, and $79,994 for the gas division.

With respect to the issue of whether remaining amounts of the Company's incentive compensation expense are reasonable in amount, the results of the compensation study indicate that Unitil's incentive compensation target levels are aligned with, or slightly below, the market median (Exhs. DPU 6-9, Att. 1, at 21-24 (electric); DPU 5-1, Att. 1, at 21-24 (gas)). Thus, we find that the remaining amounts are reasonable.

3. Healthcare Expenses

a. Introduction

During the test year, the Company booked $376,652 in medical, dental, and vision insurance expenses to its electric division, comprising $41,841 in Unitil direct costs and $334,811 allocated from USC (Exhs. Sch. RevReq-3-6 (Rev. 4) (electric); Unitil-WP 3.1 (Rev. 4) (electric); Unitil-WP 3.2 (Rev. 4) (electric)). The Company proposes to increase its healthcare expense for its electric division by $304,355 (Exh. Sch. RevReq-3-6 (Rev. 4) (electric)). Of the proposed increase, $15,528 is allocated to internal transmission and the remaining $288,826 is allocated to base distribution (Exh. Sch. RevReq-3-6 (Rev. 4) (electric)).

During the test year, the Company booked $261,373 in medical, dental, and vision insurance expenses to its gas division, comprising $37,668 in Unitil direct costs and $223,705 allocated from USC (Exhs. Sch. RevReq-3-9 (Rev. 4) (gas); Unitil-WP 2.1 (Rev. 4) (gas); Unitil-WP 2.2 (Rev. 4) (gas)). The Company proposes to increase its healthcare expenses for its gas division by $247,004 (Exh. Sch. RevReq-3-9 (Rev. 4) (gas)).

The Company offers group medical coverage to their employees through Anthem, Inc., and group dental coverage through Northeast Delta Dental (Exhs. Unitil-JFC-1, at 16 (electric); DPU 12-20 (electric); DPU 46-16 (electric); Unitil-JFC-1, at 16 (gas); DPU 11-24 (gas); DPU 37-16 (gas)). Non-union employees receive medical coverage through the Consumer Directed Health Plan while union employees receive medical coverage through either the Consumer Directed Health Plan or an Exclusive Provider Organization plan (Exh. Unitil-JFC-1, at 16 (electric); Unitil-JFC-1, at 16 (gas)). The Company self-insures its employee benefits for medical, dental, and vision coverage, such that the first $200,000 in medical claims is covered through self-insurance, while claims over $200,000 per family are covered by reinsurance (Exh. AG 1-63). In addition, if total medical claims for the year exceed 125 percent of expected claims, then all claims above 125 percent of expected claims are also paid by the reinsurer (Exh. AG 1-63).

To determine its pro forma medical, dental, and vision insurance expense, the Company first developed an employee participant count for each insurance plan by type of coverage, excluding those employees who choose to opt out of medical plans (Exhs. Unitil-JFC-1, at 16 (electric); Unitil-JFC-1, at 16 (gas)). The Company applied 2023 working rates[78] to employee participant counts to derive estimated 2023 plan costs (Exhs. Unitil-JFC-1, at 16-17 (electric); Unitil-JFC-1, at 16-17 (gas)). These costs were then reduced by employee contributions and increased by the Company's health spending account contributions, as well as payments to those employees who opt out of coverage (Exhs. Unitil-JFC-1, at 17 (electric); Unitil-JFC-1, at 17

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78 A working rate represents the per-employee expected claims levels for the following year. D.P.U. 17-05, at 147 n.70.

(gas)). These costs were then increased by 2024 working rates to arrive at the pro forma medical and dental insurance expenses, which were allocated to the electric and gas divisions accordingly (Exh. Unitil-JFC-1, at 17; Unitil-JFC-1, at 17 (gas)).

b. Positions of the Parties

Unitil contends that all employees are eligible for some form of health insurance, and all are able to opt out of receiving healthcare coverage through the Company (Company Brief at 197 (electric); Company Brief at 167 (gas)). Unitil asserts that there is a significant savings to the Company when employees enroll in a plan that is not Company-sponsored, such as eligible medical plans through their spouse (Company Brief at 197(electric); Company Brief at 167 (gas)). Unitil maintains that it has taken appropriate steps to identify and implement measures that will mitigate healthcare expenses, while maintaining the strength and value of benefits offered to employees (Company Brief at 193-198 (electric); Company Brief at 163-168 (gas)). Specifically, the Company asserts that it compares the coverage and cost of its insurance programs to market alternatives to ensure that the value for the cost of insurance is maintained and that costs are contained as much as feasible (Company Brief at 193 (electric), citing Exh. Unitil-JFC-1, at 13 (electric); Company Brief at 163 (gas)). In addition, the Company contends that it meets with outside insurers to determine if a vendor change, plan change, or cost increases are necessary to manage the insurance plan responsibly (Company Brief at 193 (electric), citing Exhs. DPU 12-7 & Atts. (electric); DPU 46-5 (electric); Company Brief at 163-164 (gas)). No intervenor addressed the Company's healthcare expenses on brief.

c. Analysis and Findings

To be included in rates, healthcare expenses, such as medical, dental, and vision, must be reasonable. D.P.U. 92-78, at 29-30; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53 (1991). Further, companies must demonstrate that they have acted to contain their healthcare costs in a reasonable, effective manner. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; D.P.U. 91-106/91-138, at 53. Finally, any post-test-year adjustments to healthcare expense must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986).

As an initial matter, the Department finds that Unitil's test-year healthcare expenses are in line with our standard and that the Company has taken reasonable and effective measures to contain its healthcare costs (see, e.g., Exhs. Unitil-JFC-1, at 13-17 (electric); AG 1-52 (electric); DPU 12-7 (electric); DPU 12-9 & Atts.; DPU 12-17 & Atts. (electric); DPU 12-18 (electric) DPU 46-10 & Att.; DPU 46-12 (electric); Unitil-JFC-1, at 13-17 (gas); AG 1-52 (gas); DPU 11-11 & Atts. (gas); DPU 11-13 & Atts. (gas); DPU 11-21 & Atts. (gas); DPU 37-5 (gas); DPU 37-10 & Att. (gas)). These efforts include frequently comparing the coverage and cost of medical insurance to market alternatives; working with a benefits broker to ensure that the benefits offerings are competitive, reasonable, and cost effective; offering an alternative plan for non-union employees that included higher deductibles and coinsurance payments; switching plans for qualified retirees; using a third-party administrator for self-funded health plans; offering a healthcare shopping and savings program; and offering wellness programs to plan participants to defer the need for medical services through the promotion of healthy habits and education. The record shows that these efforts have led to meaningful cost savings

(Exhs. DPU 12-9 & Atts. (electric); DPU 12-17 & Atts. 3-4 (electric); DPU 46-10 & Att. (electric); DPU 11-13 & Atts. (gas); DPU 11-21 & Atts. 3-4 (gas); DPU 37-10 & Att. (gas)).

With regard to Unitil's proposed post-test-year adjustments, the Department has previously denied recovery of pro forma healthcare expenses based on working rates derived from actuarial estimates encompassing a broad-based pool of insured parties. D.P.U. 15-80/D.P.U. 15-81, at 137; D.P.U. 13-90, at 94. In this case, however, the working rates were determined using information from the claims experience within Unitil's health plans (see, e.g., Exhs. Unitil-JFC-1, at 16-18 (electric); DPU 46-6 (electric); Unitil-JFC-1, at 16-18 (gas) DPU 37-6 (gas)). The Company's external benefits consultants developed the working rate using actuarial principles, and the rates were based on the Company's actual insurance claims and cost trends experienced during the two years prior to the test year (Exhs. Unitil-JFC-1, at 16 (electric); DPU 46-6 (electric); DPU 46-7, Atts. 1-2 (electric); Unitil-JFC-1, at 16 (gas); DPU 37-6 (gas); DPU 37-7 & Atts. 1-2 (gas)). Therefore, we conclude that Unitil's proposed working rates are sufficiently correlated to its actual healthcare expense accounting, rather than that of a broad-based pool of insured entities, to warrant its use in determining the Company's healthcare expenses in this proceeding. D.P.U. 15-155, at 176-177. Based on the foregoing, the Department accepts the Company's test-year healthcare expense and proposal to increase it by $304,355 ($15,528 assigned to internal transmission and $288,826 assigned to base distribution) and $247,004 for its electric and gas divisions, respectively.

B. 401(k) Plan Expenses

1. Introduction

During the test year, Unitil booked $339,775 in 401(k) plan expense to its electric division, of which $88,580 represents direct Company expense and $251,195 represents expense allocated from USC (Exhs. Sch. RevReq-3-7 (Rev. 4) (electric); Unitil-WP 4.3 (Rev. 4) (electric)). Of the total 401(k) plan expense, $322,439 represents distribution-related expense after assigning $17,336, or 5.1021 percent, to internal transmission (Exh. Sch. RevReq-3-7 (Rev. 4) (electric)). During the test year, Unitil booked $251,358 in 401(k) plan expense to its gas division, of which $83,522 represents direct Company expense and $167,837 represents expense allocated from USC (Exhs. Sch. RevReq-3-10 (Rev. 4) (gas); Unitil-WP 3.3 (Rev. 4) (gas)). Unitil tracks its 401(k) expense by combining Company contributions and Company matches into a single expense for the Company and USC (Exhs. DPU 42-4 (electric); DPU 34-7 (gas)). For Unitil's direct expense, it allocates its 401(k) expense, exclusive of capitalization, to the electric and gas divisions based on the Company's O&M allocation factors (Exhs. Unitil-WP 4.3 (Rev. 4) (electric); Unitil-WP 3.2 (Rev. 4) (gas)).

In its initial filing, the Company proposed to increase its test-year 401(k) expense by $42,969 and $31,556 for the electric (net of internal transmission) and gas divisions, respectively, to incorporate the effect of wage increases that took effect during 2023, as well as anticipated 2024 and 2025 wage increases (Exhs. Unitil-JFC-1, at 21 (electric); Unitil-JFC-1, at 21-22 (gas); Sch. RevReq-3-7 (electric); Sch. RevReq-3-10 (gas)). During the proceeding, Unitil updated its proposed increases to 401(k) expense to $43,108 and $33,185 for the electric (net of internal transmission) and gas divisions, respectively, incorporating the effects of updating the Company's non-union payroll expense for actual increases granted in 2023 and 2024, as well as USC's actual payroll increase granted in 2024 (Exhs. Sch. RevReq-3 (Rev. 4) (electric); Sch. RevReq-3-7 (Rev. 4) (electric); Sch. RevReq-3 (Rev. 2-4) (gas); Sch. RevReq-3-10 (Rev. 2-4) (gas)). The Company reiterated its proposal on brief (Company Brief at 198-199 (electric); Company Brief at 169-170 (gas)). No other party addressed this issue on brief.

2. Analysis and Findings

The Department has found that employee contributions to utility-sponsored savings plans are voluntary and, thus, subject to fluctuation. D.P.U. 13-90, at 96; D.P.U. 92-250, at 48; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; Commonwealth Electric Company, D.P.U. 88-135/151, at 68 (1989). In the absence of a demonstration that the post-test-year participation levels are more representative of future participation than the total employee contributions made during the test year, the Department has declined to permit any adjustment above the expense booked during the test year. D.P.U. 17-170, at 99-100; D.P.U. 13-90, at 96-97; D.P.U. 92-250, at 48; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; D.P.U. 88-135/151, at 68. One factor that would influence the 401(k) expense level would be the hiring of additional employees. D.P.U. 13-90, at 97-98; D.P.U. 10-114, at 150.

Unitil's 401(k) plan options include a regular plan for participants in the Company's pension plan and an enhanced plan available to non-participating employees (Exhs. DPU 10-13 & Att. (electric); DPU 10-14 & Att. (gas)). Unitil's regular 401(k) plan provides for a Company match of up to three percent of the eligible compensation (Exhs. DPU 10-13 & Att. (electric); DPU 10-14 & Att. (gas)). Non-union employees hired after January 1, 2010, as well as non-union employees who elect a frozen pension benefit and union employees hired after January 1, 2013, participate in Unitil's 401(k) enhanced plan, which provides for a Company contribution equal to four percent of eligible compensation, plus a Company match of up to six percent of the eligible compensation (Exhs. DPU 10-13 & Att. (electric); DPU 10-14 & Att. (gas)).

During the proceeding, the Company stated that its 401(k) expense obligation increases when payroll increases because the 401(k) expense, including the Company contribution and Company match, is a percentage of an employee's pay (Exhs. DPU 10-13 (electric); DPU 10-14 (gas)). Nonetheless, the Company's test-year 401(k) expense decreased from 2021 by 3.99 percent[79] for the electric division and increased by 1.96 percent[80] for the gas division, while the overall payroll increases for union and non-union employees in 2022 averaged 3.7 percent[81] (Exhs. AG 1-40, Att. 1 (Rev. 2) (electric); AG 1-40, Att. 1 (Rev. 2) (gas); AG 1-41, Att.). Similarly, the test-year 401(k) expense allocated from USC decreased from 2021 by

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79 [($193,449 - $104,863) ÷ ($199,975 - $107,704)] – 100 percent = -3.99 percent (Exh. AG 1-40, Att. 1 (Rev. 2) (electric))

80 [($183,645 - $100,125) ÷ ($180,930 - $99,013)] – 100 percent = 1.96 percent (Exh. AG 1-40, Att. 1 (Rev. 2) (gas))

81 (3.5 percent + 3.9 percent) ÷2 = 3.7 percent (Exh. AG 1-41, Att.)

3.59 percent[82] and 1.17 percent[83] for the electric and divisions, respectively, while the payroll increase was 5.1 percent (Exhs. Unitil-WP 4.3 (Rev. 4) (electric); AG 1-40, Att. 2 (Rev.) (electric); Unitil-WP 3.3 (Rev. 4) (gas); AG 1-40, Att. 2 (Rev.) (gas); AG 1-41, Att.). Moreover, the Company's 401(k) plan participants decreased by seven percent from 2022 levels, or five employees, and USC's 401(k) plan participants decreased by nine percent, or 30 employees in 2023 (Exh. DPU 24-10 (electric); DPU 20-10 (gas)). After the test year, the total number of employees at the Company increased by three and at USC increased by four (Exh. AG 1-44, Att.).

Based on the foregoing, the Company has not demonstrated that the post-test-year participation levels are more representative of future participation than those contributions made during the test year. As such, the Department declines to adjust the test-year 401(k) expense. Accordingly, the Department decreases the Company's proposed 401(k) expense for the electric division by $43,108 and reduces the Company's proposed 401(k) expense for the gas division by $33,185.

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82 $251,195 divided by $260,557, the 2021 401(k) expense allocated from USC for the electric division, results in 96.41 percent, representing a decrease of 3.59 percent (Exhs. Unitil-WP 4.3 (Rev. 4) (electric); AG 1-40, Att. 2 (Rev.) (electric)).

83 $167,837 divided by $169,830, the 2021 401(k) expense allocated from USC for the gas division, results in 98.83 percent, representing a decrease of 1.17 percent (Exhs. Unitil-WP 3.3 (Rev. 4) (gas); AG 1-40, Att. 2 (Rev.) (gas)).

C. Deferred Compensation

1. Introduction

Unitil has provided its key employees a nonqualified deferred compensation plan as part of its competitive compensation package since 2019, in recognition of the enrollment restrictions in its other pension plans (Exhs. Unitil-CGDN-1, at 30 (electric); Unitil-JFC-1, at 22 (electric); Unitil-CGDN-1, at 28 (gas); Unitil-JFC-1, at 22 (gas)). In its initial filing, the Company reported test-year deferred compensation expenses of $21,374 for its electric division (net of internal transmission) and $15,792 for its gas division (Exhs. Sch. RevReq-3-7 (electric); Sch. RevReq-3-10 (gas)). During the proceeding, the Company revised its proposal to base its proposed deferred compensation expense adjustment on 2023 eligible compensation expense, and made corrections to the USC labor and overhead billing rates for the electric and gas divisions from 15.76 percent to 15.14 percent and from 11.05 percent to 11.10 percent, respectively, resulting in a revised expense of $18,617 for the electric division (net of internal transmission) and $14,664 for the gas division (Exhs. Sch. RevReq-3-7 (Rev. 4) (electric); Unitil-WP 4.6 & Rev. 4 (electric); Sch. RevReq-3-10 & Rev. 4 (gas); Unitil-WP 3.6 & Rev. 4). The Company proposes to increase the deferred compensation by $10,128 for the electric division (net of internal transmission) and $5,575 for the gas division to incorporate USC's salary increases of 5.74 percent for 2023, 5.98 percent for 2024, and a proposed three percent increase for 2025 (Exhs. Sch. RevReq-3-7 (Rev. 4) (electric); Unitil-WP 4.6 & Rev. 4 (electric); Sch. RevReq-3-10 (Rev. 4) (gas); Unitil- WP 3.6 & Rev. 4 (gas); AG 4-12 (Rev.)).

The Company reiterated its proposal on brief (Company Brief at 200 (electric); Company Brief at 170 (gas)). No other party addressed this issue on brief.

2. Analysis and Findings

In a regulated monopoly environment, such as the one in which EDCs and LDCs operate, companies compete with other regulated and non-regulated companies to attract and retain employees. Accordingly, regulated monopolies must offer employee compensation packages that are competitive with these other companies. D.P.U. 92-250, at 55. Because regulated monopolies are not subject to the same level of product competition that creates the downward pressure on employee compensation expenses in a competitive market environment, regulators review a company's employee compensation expenses to ensure the reasonableness of such expenses. D.P.U. 92-250, at 55; see also D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 45-46; D.P.U. 86-86, at 8. Further, any post-test-year adjustments must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 45-46; D.P.U. 86-86, at 8.

As an initial matter, the Company's proposal to base its deferred compensation expense on 2023 operations departs from the test-year expense on which the Department relies for setting the representative level of expense. See Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); New England Telephone & Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). Consistent with our precedent, the Department will rely on the 2022 test-year expense as a starting point to determine the reasonableness of the deferred compensation expense (Tr. 4, at 391-392). D.P.U. 92-250, at 55.

To determine the allowed 2022 test-year deferred compensation amounts, the Department relies on USC's chart of accounts. The Company derives its proposed deferred compensation expense from the eligible compensation of the participants according to the deferred compensation plan document rather than the actual expense allocated from USC (Exhs. Unitil-WP 4.6 (Rev. 4) (electric); DPU 10-18 (electric); Unitil-WP 3.6 (Rev. 4) (gas); DPU 10-19 (gas)). According to Unitil's deferred compensation plan documentation, participants in the plan are required to make an annual deferral election on the percentage of the compensation to be deferred, and a default six percent deferral is applied if the participants fail to make the election (Exhs. DPU 10-13, Att. 1, at 78 (electric); DPU 10-14, Att. 1, at 78 (gas)). The Company also makes a fail-safe contribution of four percent of the compensation regardless of the employee's participating status (Exhs. DPU 10-13, Att. 1, at 10 (electric); DPU 10-14, Att. 1, at 10 (gas)). The Company's proposal in the instant case assumes ten percent of the total eligible compensation of the plan participants, and not the deferred compensation expense recorded for the test year before adding pro forma adjustments (Exhs. Unitil-WP 4.6 (Rev. 4) (electric); DPU 42-2, Att. (electric); DPU 42-10 (electric); Unitil-WP 3.6 (Rev. 4) (gas); DPU 34-5, Att. (gas); DPU 34-16 (gas)). The cost allocation from USC for deferred compensation is recorded in the Company's O&M expense accounts (Tr. 4, at 385). Therefore, the Department uses the Company's O&M expense amounts recorded in the 2022 test year.[84] After applying USC's labor and overhead ratios exclusive of capitalization, the test-year deferred compensation allocated to the electric division is $14,424 (net of internal transmission) and the

84 During the proceeding, the Company provided the deferred compensation expense for the years 2019 through 2023 that correspond to the amounts recorded in USC's chart of accounts (Exhs. DPU 10-14 (electric); DPU 10-18 (electric); AG 1-34, Att. 1, at 4 (electric); RR-DPU-41, Att. 2, at 3 (electric); DPU 10-18 (gas); DPU 10-19 (gas); AG 1-34, Att. 1, at 4 (gas); RR-DPU-41, Att. 2, at 3 (gas)).

amount allocated to the gas division is $10,156 (Exhs. DPU 42-2, Att. (electric); DPU 34-5, Att. (gas)).[85] Therefore, the Department allows test-year deferred compensation for the electric division of $14,424 and for the gas division of $10,156.

Finally, during the proceeding, Unitil stated that its deferred compensation is directly correlated with payroll expense due to employee contributions and the Company match, which equal a percentage of the employee's compensation (Exh. DPU 10-15 (electric); DPU 10-16 (gas)). Nonetheless, Unitil's test-year deferred compensation contribution increased by 34.95 percent while the payroll increase was 5.1 percent, and the 2021 deferred compensation contribution increased by 18.1 percent while the payroll increased 4.5 percent (Exhs. AG 1-41, Att. (electric); DPU 10-18 (electric); DPU 10-19 (gas)). The percentage of compensation deferred for each participant varies depending on the annual election by the participants (Exhs. DPU 10-13, Att. 1, at 78 (electric); DPU 10-14, Att. 1, at 78 (gas)). While Unitil's fail-safe contribution portion may be quantifiable, the Department finds that the Company's assumption that all participating employees will opt for six percent deferral is speculative. As such, the Department finds that the post-test-year adjustment to test-year deferred compensation expenses is not known and measurable for either the electric or gas divisions. D.P.U. 17-170, at 99-100; D.P.U. 13-90, at 96-97; D.P.U. 92-250, at 48; D.P.U. 89-114/90-331/91-80 (Phase One) at 66-67; D.P.U. 88-135/151, at 68. Accordingly, the Department decreases the

85 The expense amounts are the Company's allocated deferred compensation contribution made to the individual deferred compensation accounts managed by John Hancock (Tr. 4, at 376-378).

Company's total proposed deferred compensation expense by $14,321[86] for the electric division and by $10,083[87] for the gas division.

D. Payroll-Related Taxes

1. Introduction

Unitil initially proposed to increase its cost of service by $35,900 (with $1,832 assigned to internal transmission and $34,068 assigned to base distribution) and $31,417 for the electric division and the gas division, respectively, to recognize additional payroll taxes associated with its Social Security and Medicare taxes (Exhs. Unitil-CGDN-1, at 59 (electric); Unitil-JFC-1, at 12-13 (electric); Sch. RevReq-3-23 (electric); Unitil-CGDN-1, at 47 (gas); Unitil-JFC-1, at 12-13 (gas); Sch. RevReq-3-23 (Rev. 4) (gas)). After updating its payroll expense based on the wage increases described in Sections VI.A.1.b.iii. and VI.A.1.c.iii. above, the Company proposes to increase its cost of service by $32,926 and $30,373 for the electric division and the gas division, respectively (Exhs. Sch. RevReq-3-23 (Rev. 4) (electric); Sch. RevReq-3-23 (Rev. 4) (gas)). For the electric division, $1,680 is assigned to internal transmission and $31,246 is assigned to base distribution (Exh. Sch. RevReq-3-23 (Rev. 4) (electric)).

On brief, the Company summarized its calculation of the payroll taxes (Company Brief at 248 (electric); Company Brief at 212 (gas)). No intervenor addressed this issue on brief.

86 $14,424 (allowed) - $28,745 (Company proposed) = - $14,321 (see Exh. Sch. RevReq-3-7 (Rev. 4)) (electric))

87 $10,156 (allowed) - $20,239 (Company proposed) = - $10,083 (see Exh. Sch. RevReq-3-10 (Rev. 4) (gas))

2. Analysis and Findings

The Department has examined Unitil's supporting workpapers and finds that the Company has appropriately applied the correct tax rates for Social Security and Medicare (Exhs. Sch. RevReq-3-23 (Rev. 4) (electric); Sch. RevReq-3-23 (Rev. 4) (gas)). Based on the reduction associated with the non-union wage increases in Section VI.A.1.c.iii. above and the removal of the EPS component of the Restricted Stock Plan in Section VI.A.2.c. above, appropriate adjustments must be made to payroll tax expense.

Based on the reduction of non-union payroll increase, the Department calculated a revised payroll tax of $26,392 for the electric division ($1,347, or 5.102 percent, is assigned to internal transmission, and the remaining $25,045 is assigned to base distribution), and $24,303 for the gas division, a reduction of $6,200 (net of internal transmission) and $6,070, respectively. Based on the adjustment to the Company's Restricted Stock Plan to remove the component associated with EPS, a corresponding adjustment must be made to payroll tax expense. Utilizing the Medicare tax rate of 1.45 percent, the Company has calculated the effect on payroll taxes from adjusting the restricted stock expense. The produces further reductions to the proposed cost of service of $1,647 for the electric division and $1,160 for the gas division, respectively.[88]

Accordingly, based on the adjustments above, the Department will reduce the electric division's payroll tax by $7,848. The Department will reduce the gas division's payroll tax by $7,230.

[88] $113,615 x 1.45 percent = $1,647; and $79,994 x 1.45 percent = $1,160

E. Depreciation Expense

1. Introduction

During the test year, Unitil booked $7,823,663 in depreciation expense for its electric division, of which $558,839 was assigned to internal transmission and $7,264,824 was assigned to base distribution (Exhs. Sch. RevReq-2-1 (Rev. 4) (electric); Sch. RevReq-3-18, at 1 (Rev. 4) (electric)). The Company derived an annualized depreciation expense of $8,140,915 for the electric division by applying currently authorized depreciation rates to the test-year-end depreciable plant balances, producing an annualization adjustment of $317,252, of which $18,444 was assigned to internal transmission and $298,808 was assigned to base distribution (Exhs. Sch. RevReq-3 (Rev. 4) (electric); Sch. RevReq-3-18, at 1-2 (Rev. 4) (electric)).

Based on Unitil's proposed accrual rates, the Company decreased its electric division's annualized test-year depreciation expense by $657,227, of which $24,935 was assigned to internal transmission and $632,292 was assigned to base distribution (Exh. Sch. RevReq-3-18, at 2 (Rev. 4) (electric)). By applying the Company's proposed depreciation accrual rates to electric plant balances as of December 31, 2023, Unitil proposed a rate-year depreciation expense of $7,116,024 for its electric division, of which $585,925 was assigned to internal transmission and $6,530,099 was assigned to base distribution (Exh. Sch. RevReq-3-18, at 3 (Rev. 4)).

During the test year, Unitil booked $7,134,840 in depreciation expense for its gas division (Exhs. Sch. RevReq-2-1 (Rev. 4) (gas); Sch. RevReq-3-20, at 1 (Rev. 4) (gas)). The Company derived an annualized depreciation expense of $7,556,796 for the gas division by applying currently authorized depreciation rates to the test-year-end depreciable plant balances, resulting in an annualization adjustment of $421,956 (Exh. Sch. RevReq-3-20, at 1 (Rev. 4) (gas)). Based on the Company's proposed accrual rates, Unitil increased its gas division's annualized test-year depreciation expense by $2,632,526 (Exh. Sch. RevReq-3-20, at 2 (Rev. 4) (gas)). By applying proposed accrual rates to gas plant balances as of December 31, 2023, the Company proposed a rate-year depreciation expense of $10,444,151 (Exhs. Unitil-CGGN-7, Sch. 3 (gas); Sch. RevReq-3-20, at 3 (Rev. 4) (gas)).[89]

For its electric division, the Company applied account-specific accrual rates to test-year-end depreciable plant, which resulted in a 4.09 percent composite accrual rate (Exh. Unitil-NWA-3, at 7, 51 (electric)). For its gas division, Unitil applied account-specific accrual rates to test-year-end depreciable plant, which resulted in a 5.12 percent composite accrual rate (Exh. Unitil-NWA-3, at 7, 52 (gas)). For common plant used by both the electric and gas divisions, the Company applied account-specific accrual rates, which resulted in an overall accrual rate of 2.00 percent (Exhs. Unitil-NWA-3, at 7, 51 (electric); Unitil-NWA-3, 7, 52 (gas)). These accrual rates represent a decrease from the Company's current overall accrual rate of 4.21 percent for electric plant, an increase from Unitil's current overall accrual rate of 3.73 percent for gas plant, and a decrease from the current overall accrual rate of 2.69 percent for common plant (Exhs. Sch. RevReq-3-18, at 1 (Rev. 4) (electric); Sch. RevReq-3-20, at 1 (Rev. 4) (gas)).

[89] Unitil initially proposed a rate-year depreciation expense of $10,590,135 based on projected plant balances for 2023; during the proceeding, the Company updated this amount based on actual year-end 2023 plant balances (Exhs. Sch. RevReq-3-20, at 3 (gas); Sch. RevReq-3-20, at 3 (Rev. 4) (gas)).

In support of its proposed accrual rates, the Company presented a depreciation study for each division using plant data as of December 31, 2022, and employed the overall straight-line method, average service life ("ASL") procedure, and average remaining life technique to estimate the proposed depreciation accrual rates for most accounts[90] (Exhs. Unitil-NWA-1, at 4, 6, 12-13 (electric); Unitil-NWA-3, at 6, 9-11, 48-49 (electric); Unitil-NWA-1, at 4, 6, 12-13 (gas); Unitil-NWA-3, at 6-7, 9-11, 49 (gas)). The Company's depreciation study analyzed accounting entries of plant transactions from the period 1970 through 2022 for the electric division and 1969 through 2022 for the gas division (Exhs. Unitil-NWA-1, at 14 (electric); Unitil-NWA-3, at 34-35 (electric); Unitil-NWA-1, at 14 (gas); Unitil-NWA-3, at 34-35 (gas)).[91] Unitil estimated the service life and net salvage[92] characteristics for depreciable plant accounts, and next used the estimates to calculate composite remaining lives and annual depreciation accrual rates for each account (Exhs. Unitil-NWA-1, at 6-7 (electric); Unitil-NWA-3, at 6, 48-52 (electric); Unitil-NWA-1, at 6-7, 11-12, 15 (gas); Unitil-NWA-3, at 6, 48-52 (gas)). To determine service lives, the Company used the retirement rate method to create life tables that,

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[90] For Unitil's general plant assets, specifically general plant accounts 391.00, 393.00, 394.00, 395.00, 397.00, and 398.00, the Company used the straight-line method of amortization (Exhs. Unitil-NWA-1, at 6, 13-14 (electric); Unitil-NWA-3, at 6, 11, 46 (electric); Unitil-NWA-1, at 6, 13-14 (gas); Unitil-NWA-3, at 6, 11, 46 (gas)). Additionally, Unitil proposed a five-year amortization for its unrecovered reserve (Exhs. Unitil-NWA-1, at 14 (electric); Unitil-NWA-1, at 14 (gas)).

[91] Aged retirement and other plant accounting data were compiled for the years 2008 through 2022, and unaged retirement data from 1970 to 2008 was statistically aged for most accounts (Exhs. Unitil-NWA-3, at 34-35 (electric); Unitil-NWA-3, at 34-35 (gas)).

[92] Net salvage is the resulting difference between the gross salvage of an asset when it is disposed, less its associated cost of removal from service (Exhs. Unitil-NWA-3, at 39 (electric); Unitil-NWA-3, at 40 (gas)).

when plotted, show an original survivor curve that is then compared to Iowa Curves[93] to determine an ASL for each plant account (Exhs. Unitil-NWA-1, at 4-9 (electric); Unitil-NWA-3, at 20, 26 (electric); Unitil-NWA-1, at 7-8 (gas); Unitil-NWA-3, at 20, 26 (gas)). To determine net salvage values, the Company reviewed its actual salvage and cost of removal data for the period 1981 through 2022 (Exhs. Unitil-NWA-1, at 11-12 (electric); Unitil-NWA-3, at 39 (electric); Unitil-NWA-1, at 11-12 (gas); Unitil-NWA-3, at 40 (gas)).

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General contends that Unitil has proposed shorter service lives than what is indicated by the Company's historical retirement data (Attorney General Brief at 73, citing Exh. AG-DJG-1, at 6-22). According to the Attorney General, the depreciation rates proffered by her expert witness are based on empirical evidence and objective statistical analysis (Attorney General Brief at 73; Attorney General Reply Brief at 19). She asserts that comparatively, the Company conducted a basic statistical analysis and artificially decreased depreciation rates without supporting evidence (Attorney General Reply Brief at 19). Additionally, the Attorney General maintains that her proposed curves provide a better mathematical fit to the data than

93 Iowa Curves are frequency distribution curves initially developed at the Iowa State College Engineering Experiment Station during the 1920s and 1930s; 18 curve types were initially published in 1935, and four additional survivor curves were identified in 1957 (Exhs. Unitil-NWA-3, at 14-20 (electric); Unitil-NWA-3, at 14-20 (gas)). Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company, and Canal Electric Company, D.T.E. 06-40, at 66-67 n.44 (2006). These curves are widely accepted in determining average life frequencies for utility plant.

those proposed by the Company (Attorney General Brief at 73-77). Based on her proposed depreciation accrual rates, the Attorney General recommends the Department reduce depreciation expense by $739,636 and $1,114,810 for the electric and gas divisions, respectively (Attorney General Brief at 71, 77; Attorney General Reply Brief at 19-20).

The Attorney General argues the Company has failed to prove that its proposed depreciation rates are not excessive, and she recommends that the Department deny the Company's proposal and instead adopt her proposed depreciation rates (Attorney General Brief at 70, 72-73, 76; Attorney General Reply Brief at 19). The Attorney General's specific account and accrual rate recommendations and supporting arguments are detailed below.

ii. Account 353 – Transmission Station Equipment – Electric

For the Company's electric division, the Attorney General challenges Unitil's proposed R3-55 curve for Account 353, and she argues that an R2-62 curve is more appropriate (Attorney General Brief at 72). The Attorney General contends that her proposed curve demonstrates both a better visual and mathematical fit than the Company's curve and, therefore, the Department should accept her depreciation accrual rate for this account (Attorney General Reply Brief at 72-73).

iii. Account 362 – Distribution Station Equipment – Electric

The Attorney General disagrees with Unitil's recommended S2.5-50 curve for Account 362, and she argues that an R2.5-60 curve is more appropriate (Attorney General Brief at 72, 75). The Attorney General contends that her proposed curve demonstrates both a better visual and mathematical fit compared to the Company's curve and, therefore, the Department should accept her depreciation accrual rate for this account (Attorney General Reply Brief at 72-73).

iv. Account 364 – Poles, Towers, and Fixtures – Electric

The Attorney General opposes Unitil's recommendation of an R2.5-55 curve for Account 364, and she claims that an R2-61 curve is more appropriate (Attorney General Brief at 72). The Attorney General maintains that her proposed curve demonstrates both a better visual and mathematical fit than the Company's curve and, therefore, the Department should accept her depreciation accrual rate for this account (Attorney General Reply Brief at 72-73).

v. Account 367 – Underground Conductors & Devices – Electric

The Attorney General challenges Unitil's recommendation of an R3-55 curve for Account 367, arguing that an R3-65 curve is more appropriate (Attorney General Brief at 72). The Attorney General suggests that her proposed curve demonstrates both a better visual and mathematical fit than the Company's curve and, therefore, the Department should accept her depreciation accrual rate for this account (Attorney General Reply Brief at 72-73).

vi. Account 368 – Line Transformers – Electric

The Attorney General rejects Unitil's recommendation of an R2-40 curve for Account 368, and instead proposes an R2-46 curve as more appropriate (Attorney General Brief at 72). The Attorney General contends that her proposed curve demonstrates both a better visual and mathematical fit than the Company's curve and, therefore, the Department should accept her depreciation accrual rate for this account (Attorney General Reply Brief at 72-73).

vii. Account 320 – Other Equipment – Gas

For the Company's gas division, the Attorney General proposes an R1-34 curve for Account 320 - Other Equipment (Attorney General Brief at 72, 76). The Attorney General contends the R1-34 curve provides a more accurate fit to the Company's observed historical retirement than Unitil's proposed S0-25 curve (Attorney General Brief at 76). The Attorney General asserts that the Company's proposed ASL for this account is too short and results in a depreciation rate that is too high (Attorney General Brief at 76).

viii. Account 376 – Mains – Gas

For the gas division's Account 376 – Mains, the Attorney General proposes an R2.5-76 curve (Attorney General Brief at 72). The Attorney General asserts that the Company's proposed service life for this account is too short and results in unreasonably high depreciation rates (Attorney General Brief at 73).

ix. Account 380 – Services – Gas

The Attorney General recommends an L4-47 curve for the gas division's Account 380 – Services (Attorney General Brief at 72). The Attorney General maintains that her proposed curve is more accurate for Account 380 than the Company's proposed R3-45 curve, which the Attorney General suggests is unreasonably short (Attorney General Brief at 72-74, 77).

b. Company

Unitil submits that its proposed depreciation rates are the result of a detailed depreciation study for each division and are reasonable (Company Brief at 311-312, 319-321 (electric); Company Brief at 244-245, 254 (gas)). The Company also contends that the depreciation study in the instant proceeding is consistent with the Company's last study in its most recent base rate distribution proceedings, D.P.U. 19-130 (electric) and D.P.U. 19-131 (gas) (Company Brief at 313-314 (electric), citing Exh. Unitil-NWA-1, at 4 & n.2 (electric); Company Brief at 247 (gas), citing Exh. Unitil-NWA-1, at 4 & n.2 (gas)).

The Company argues that, contrary to the Attorney General's assertions, its proposed depreciation rates cannot be considered excessive given that they result in a decrease in depreciation expense relative to its currently approved rates for the electric division (Company Brief at 320 (electric)). Moreover, the Company contends that its proposed average service lives are similar to current estimates based on a previously approved depreciation study with data through 2018 (Company Brief at 320 (electric); Company Brief at 253 (gas)). Additionally, the Company notes that while the Attorney General relied solely on statistical analyses for her recommendations, the Company's expert witness also performed site visits and had discussions with Company management (Company Reply Brief at 60).

Unitil further argues that the Attorney General's recommendation to extend the service lives of various accounts is not justified by any events occurring since the Company's last base distribution rate proceedings, and that the Attorney General's proposals are not only inconsistent with her position in D.P.U. 20-80, but also ignore the realities of the anticipated energy transition (Company Brief at 320-321 (electric); Company Brief at 253-254 (gas)). In this regard, Unitil contends that the Commonwealth's transition to net zero GHG emissions could impact the service lives of both electric and gas assets and should be considered as relevant context for assessing the Company's depreciation proposal and, in particular, rejecting the Attorney General's recommended service lives (Company Brief at 314-315 (electric); Company Brief at 248 (gas)). Unitil notes, however, that since the Department has not provided guidance on this topic, the Company did not make specific changes to service lives or depreciation results with respect to achieving climate goals (Company Brief at 314-315 (electric); Company Brief at 248 (gas)). Finally, Unitil asserts that its operating environment will change dramatically over the coming 20 years due to the electrification of transportation and heating and the achievement of energy transition goals, which the Company maintains are likely to shorten the average service lives of both electric and gas assets (Company Brief at 321 (electric); Company Brief at 248, 253-254 (gas); Company Reply Brief at 60-61).

3. Analysis and Findings

a. Standard of Review

Depreciation expense allows a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 75 (1998); D.P.U. 96-50 (Phase I) at 104; D.P.U. 84-135, at 23; D.P.U. 1350, at 97. Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a witness reaches a conclusion about a depreciation study that is at variance with that witness' engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 20-21 (1980).

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 132 (2002); D.P.U. 92-250, at 64.

Because depreciation studies rely by their nature on examining historical performance to assess future events, a degree of subjectivity is inevitable.[94] Nevertheless, the product of a depreciation study consists of specific accrual rates to be applied to specific account balances associated with depreciable property. A mere assertion that judgment and experience warrant a particular conclusion does not constitute evidence. See Eastern Edison Company, D.P.U. 243, at 16-17 (1980); D.P.U. 200, at 20-21; Lowell Gas Company, D.P.U. 19037/19037-A at 23 (1977).

It thus follows that the reviewer of a depreciation study must be able to determine the reasons why the preparer of the study chose one particular life-span curve or salvage value over another, preferably through the direct filing and at least in the form of comprehensive responses to well-prepared discovery. The Department will continue to look to an expert witness for interpretation of statistical analyses but will consider other expert testimony and evidence that challenges the preparer's interpretation and expects sufficient justification on the record for any variances resulting from the engineering and statistical analyses. D.P.U. 89-114/90-331/91-80 (Phase One) at 53-55. To the extent a depreciation study provides a clear and comprehensive explanation of the factors that went into the selection of accrual rates, such an approach will facilitate review by the Department and intervenors.

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94 The element of subjectivity is especially relevant in the calculation of net salvage factors where the cost to demolish or retire facilities cannot be established with certainty until the actual event occurs. D.P.U. 92-250, at 66; Boston Edison Company, D.P.U. 1720, at 44 (1984); D.P.U. 1350, at 109-110.

b. Account-by-Account Analysis

i. Account 353 – Transmission Station Equipment – Electric

The Company proposes an accrual rate for Account 353 of 3.42 percent, based on the continued use of its currently authorized R3-55 curve (Exh. Unitil-NWA-3, at 50, 229 (electric)). Alternatively, the Attorney General proposes a R2-62 curve, producing an accrual rate of 2.75 percent (Exhs. AG-DJG-4 (electric); AG-DJG-6, at 1 (electric)).

For its depreciation study, the Company analyzed two experience bands:[95] one encompassing the years 1969 through 2022, and the other spanning 2008 through 2022 (Exh. Unitil-NWA-3, at 14-15, 70 (electric)). Unitil's proposed curve better approximates the broader experience band than the Attorney General's, which more closely tracks the more recent experience band (Exh. Unitil-NWA-Rebuttal at 14-15 (electric)). While both bands are considered for this account, the more recent band has limited retirement data, with assets in this account only declining to just below 80 percent surviving, which may provide less meaningful curve fitting results (Exh. Unitil-NWA-Rebuttal at 14-15 (electric)). Turning to other electric utilities with Account 353, the mean ASL utilized is 52 years, which is more in line with the Company's proposed 55-year ASL than the Attorney General's proposed ASL of 62 years (Exh. DPU 19-2, Att. (electric)). Further, while the Company notes that it has not proposed changes to service lives specifically due to increased electrification and the energy transition, the Department finds it prudent to exercise caution in not extending service lives without compelling evidence and to maintain the Company's currently approved curve-life combination for

95 Experience bands are the period of observation during which property is retired (Exh. Unitil-NWA-3, at 20 (electric)).

Account 353 (Exh. DPU 19-1, Att. 1 (electric)). The Department has reviewed the Company's depreciation study and finds that it is reasonable to leave the current curve-life combination unchanged (Exh. Unitil-NWA-3, at 50, 70-75, 177-179, 228-229 (electric)). Therefore, the Department accepts the Company's proposed depreciation accrual rate of 3.42 percent for Account 353.

ii. Account 362 – Distribution Station Equipment – Electric

The Company proposes an accrual rate for this account of 3.77 percent, based on the continued use of its currently authorized S2.5-50 curve for this account (Exh. Unitil-NWA-3, at 50, 233-235 (electric)). The Attorney General proposes a R2.5-60 curve and an accrual rate of 2.82 percent (Exh. AG-DJG-6, at 1 (electric)).

As with Account 353, Unitil's analysis and curve selection for Account 362 provide a better fit to the broader experience band with more years of retirement data than the Attorney General's selection, which more closely approximates the shorter experience band (Exh. Unitil-NWA-Rebuttal at 17-18 (electric)). For Account 362, the broader experience band provides more retirement data, with assets surviving declining to below ten percent, compared to 40 percent for the shorter and more recent band (Exh. Unitil-NWA-Rebuttal at 18 (electric)). Comparing other electric utilities with Account 362, the mean ASL for this account is 52 years, which more closely aligns with the Company's proposed ASL of 50 years than the Attorney General's proposed ASL of 60 years (Exh. DPU 19-2, Att. (electric)). Further, while the Company notes that it has not proposed changes to service lives specifically due to electrification and the energy transition, it also notes that winter peaks due to electrification, renewables and increased distributed energy resources penetration, system-wide voltage support needs, and increasingly shorter service lives of newer equipment are likely to lessen the expected service lives of assets in Account 362 (Exhs. Unitil-NWA-Rebuttal at 17 (electric); DPU 19-1, Att. 1 (electric)). The Department finds it reasonable to exercise caution in not increasing service lives without compelling evidence and to maintain the Company's currently approved curve-life combination for this account. The Department has reviewed the Company's depreciation study and finds that it is reasonable to leave the current curve-life combination unchanged (Exh. Unitil-NWA-3, at 50, 93-99, 189-191, 233-235 (electric)). Based on these considerations, the Department accepts the Company's proposed accrual rate of 3.77 percent for Account 362.

iii. Account 364 – Poles, Towers, and Fixtures – Electric

The Company proposes an accrual rate for this account of 3.77 percent, based on the continued use of its currently authorized R2.5-55 curve (Exh. Unitil-NWA-3, at 50 (electric)). Unitil recommends maintaining the 55-year ASL as reasonable (Exhs. Unitil-NWA-3, at 50 (electric); Unitil-NWA-Rebuttal at 18-20 (electric)). In comparison, the Attorney General proposes to use an R2.0-61 curve, producing an accrual rate of 3.22 percent, comparatively (Exhs. AG-DJG-1, at 17-19 (electric); AG-DJG-6, at 1 (electric)).

Unitil's proposed curve for Account 364 provides a better fit to the broader experience band than the Attorney General's proposed curve, similar to Accounts 353 and 362 above (Exh. Unitil-NWA-Rebuttal at 19 (electric)). Turning to other electric utilities with Account 364, the mean ASL utilized is 54 years, which more closely approximates the Company's proposed 55-year ASL than the Attorney General's proposed ASL of 61 years (Exh. DPU 19-2, Att. (electric)). Further, while Unitil notes that it has not proposed changes to service lives specifically due to electrification, the Company witness' discussions with management and operations personnel indicate the need to retire and replace poles and towers due to increased distributed energy resources penetration and the energy transition (Exh. DPU 19-1, Att. 1, at 3-4 (electric)). Based on these considerations, the Department finds it prudent to exercise caution in not increasing service lives without sufficient evidence and to maintain the Company's currently approved curve and ASL for this account. The Department has reviewed the Company's depreciation study and finds that it is reasonable to leave the current curve-life combination unchanged (Exh. Unitil-NWA-3, at 50, 102-108, 192-194, 237-239 (electric)). Therefore, the Department accepts Unitil's proposed accrual rate of 3.77 percent for Account 364.

iv. Account 367 – Underground Conductors & Devices – Electric

The Company proposes an accrual rate for this account of 3.57 percent, based on its currently authorized R3-55 curve (Exh. Unitil-NWA-3, at 50 (electric)). In contrast, the Attorney General proposes an R3-65 curve, producing an accrual rate of 2.83 percent (Exhs. AG-DJG-1, at 19-21 (electric); AG-DJG-6, at 1 (electric)).

The Company notes that neither its, nor the Attorney General's, proposals provide a superior fit for the Company's retirement data (Exh. Unitil-NWA-Rebuttal at 21 (electric)). Unitil explains that this is because most assets in Account 367 are relatively new and differ in their construction from older assets in this account (Exh. Unitil-NWA-Rebuttal at 21 (electric)). The Company also contends that assets in this account will be impacted by obsolescence and will need to be replaced for resiliency and reliability purposes (Exh. Unitil-NWA-Rebuttal at 22 (electric)).

For other electric utilities with Account 364, the mean ASL is 50 years, which is closer to the Company's proposed 55-year ASL and well below the Attorney General's proposed ASL of 65 years (Exh. DPU 19-2, Att. (electric)). The Department finds it prudent to exercise caution in deviating from a previously approved ASL without compelling evidence and to maintain the Company's currently approved service lives in this case. The Department has reviewed the Company's depreciation study and finds that it is reasonable to leave the current life-curve combination unchanged (Exh. Unitil-NWA-3, at 50, 102-108, 192-194, 237-239 (electric)). Therefore, the Department accepts the Company's proposed accrual rate of 3.57 percent for Account 367.

v. Account 368 – Line Transformers – Electric

The Company proposes an accrual rate for Account 368 of 3.59 percent, based on the continued use of its currently authorized R2-40 curve (Exh. Unitil-NWA-3, at 50 (electric)). The Attorney General proposes an R2-46 curve, which produces an accrual rate of 2.85 percent (Exhs. AG-DJG-1, at 21-23 (electric); AG-DJG-6, at 1 (electric)).

For Account 368, both Unitil and the Attorney General propose curves that appear to strike a balance in fit between the larger experience band encompassing the years 1970 through 2022, and the shorter experience band encompassing retirement data from 2008 through 2022 (Exh. Unitil-NWA-Rebuttal at 24 (electric)). The Company's proposed curve provides a better fit for the larger band, the Attorney General's proposed curve provides a better fit for the shorter band, and the Department considers both to be appropriate fits for the data in this account (Exh. Unitil-NWA-Rebuttal at 24 (electric)). A review of the ASLs used by other electric utilities with this account shows an average ASL of 43 years, which also suggests that both proposals are within a range of reasonableness (Exh. DPU 19-2, Att. 1 (electric)). The Company asserts that the assets in this account will need to be replaced as the pace of electrification increases and newer equipment will exhibit decreased design tolerances, which will result in reduced service lives and technological obsolescence (Exhs. Unitil-NWA-Rebuttal at 22 (electric); DPU 19-1, Att. 1, at 2-3 (electric)). In this instance, the additional information obtained by the Company's witness through discussions with management and site visits, along with the overall analysis and curve fitting, support the Company's proposal to leave the curve-life combination for this account unchanged (Exhs. DPU 19-1, Att. 1, at 2-3 (electric); DPU 19-1, Att. 2, at 1-2 (electric)). The Department has reviewed the Company's depreciation study and finds that it is reasonable to leave the current life-curve combination unchanged (Exh. Unitil-NWA-3, at 50,102-108, 192-194, 237-239 (electric)). Therefore, the Department accepts the Company's proposed accrual rate of 3.59 percent for Account 368.

i. Account 320 – Other Equipment – Gas

For the gas division's Account 320, the Company proposes a depreciation accrual rate of 4.27 percent based on maintaining the currently approved S0-25 curve (Exh. Unitil-NWA-3, at 51, 66 (gas)). Alternatively, the Attorney General proposes an accrual rate of 2.88 percent based on an R1-34 curve, which she argues is a better visual and statistical fit to the historical data (Exh. AG-DJG-1, at 4). The Company counters that for this account, its proposal is based on more than just a visual curve fitting, as it also considers the underlying assets in this account and discussions with management (Exhs. Unitil-NWA-Rebuttal at 21-22 (gas); AG 3-12 (gas); DPU 18-1, Atts. 1 & 2 (gas)). Unitil states that Account 320 includes equipment located at the Company's liquified natural gas and liquified petroleum gas facilities, which were installed in

1973 and 1960, respectively, and that the lifespan of the assets will be constrained by the life span of these facilities (Exh. Unitil-NWA-Rebuttal at 22 (gas)). The Company also notes that the context of the energy transition is important and that the Attorney General's proposal is unrealistic in light of the anticipated changes (Exhs. Unitil-NWA-Rebuttal at 22 (gas); DPU 18-5 (gas); DPU 18-6 (gas)).

The Department notes that the retirement data for this account is somewhat limited, with the curve only showing assets surviving to approximately 60 percent (Exh. Unitil-NWA-3, at 66 (gas)). A review of other gas utilities with Account 320 shows the average ASL utilized for this account is 30 years (Exh. DPU 18-2, Att. (gas)). Based on these considerations, the constraints on the assets in Account 320, and concerns raised regarding extending the average service lives of assets that may be shortened in the energy transition, the Department finds it prudent to continue the Company's use of an S0-25 curve for this account (Exhs. Unitil-NWA-Rebuttal at 21-22 (gas); DPU 18-5 (gas); DPU 18-6 (gas)). Therefore, the Department accepts the Company's proposed accrual rate for Account 320 of 4.27 percent.

ii. Account 376 – Mains – Gas

For Account 376, Unitil proposes an overall depreciation accrual rate of four percent based on an R2.5-70 curve (Exh. Unitil-NWA-3, at 51, 66 (gas)). For certain subaccounts containing leak-prone pipe, the Company uses a terminal end date and interim survivor curve as the assets are expected to be fully retired by 2034, consistent with the Company's GSEP (Exhs. Unitil-NWA-3, at 51-52 (gas); Unitil-NWA-Rebuttal at 17 (gas)). In contrast, the Attorney General proposes an overall accrual rate of approximately 3.12 percent based on an

R2.5-76[96] curve, and she rejects the use of terminal retirement dates for any subaccounts, suggesting the Company has not provided a compelling reason for their application (Exh. AG-DJG-1, at 19 (gas)).

As in initial matter, the Department has found the use of terminal retirement dates appropriate in instances where a planned retirement date for certain assets was known. D.P.U. 22-22, at 184-185 (approving terminal retirement dates associated with NSTAR Electric's AMI Implementation Plan). For Unitil, the proposal to use terminal retirement dates accounts containing leak-prone pipe is consistent with the Company's GSEP and directives from Company management that anticipate all leak-prone pipe being retired by 2034 (Exhs. Unitil-NWA-3, at 51 (gas); DPU 18-1, Atts. 1 & 2 (gas)). Therefore, the Department approves the use of terminal retirement dates for subaccounts 376.30 – Mains – Bare Steel, 376.50 – Mains – Joint Seals, 376.70 – Mains – Ductile, and 376.80 – Mains – Cast Iron (Exh. Unitil-NWA-3, at 51 (gas)).

Similar to other accounts in Unitil's depreciation study, the Company analyzed two experience bands of retirement data for Account 376, one spanning from 1969 through 2022, and the other spanning from 2008 through 2022 (Exh. Unitil-NWA-3, at 71 (gas)). Comparing the two proposed curves against the longer and shorter experience bands demonstrates that the Company's proposed curve provides an excellent fit to the shorter, most recent band, and the Attorney General's proposed curve falls between the two experience band data points

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96 The Attorney General's testimony proposes an R2.5-76 and an R2.5-77 curve for this account on different pages, with supporting curves for an R2.5-77 curve, however the Attorney General's brief references only an R2.5-76 curve (Exh. AG-DJG-1, at 4, 15-17 (gas); Attorney General Brief at 72).

(Exhs. Unitil-NWA-3, at 71 (gas); Unitil-NWA-Rebuttal at 14 (gas); AG-DJG-1, at 18 (gas)). For this account, the Department finds that the more recent experience band should be given more weight, as the more recent band more appropriately reflects activities pursuant to the Company's GSEP (Exhs. Unitil-NWA-3, at 71 (gas); Unitil-NWA-Rebuttal at 14-16; DPU 18-1, Att. 1, at 1 (gas); DPU 18-1, Att. 2, at 1 (gas)). D.P.U. 20-120, at 253. An examination of other gas utility depreciation data demonstrates that the average ASL for Account 376 is 66 years, less than both the Company's and Attorney General's proposals (Exh. DPU 18-2, Att. (gas)). Moreover, given the considerations and context of the Commonwealth's 2050 climate targets and goals, the Department finds it would be imprudent to extend ASLs of gas assets without a compelling reason (Exhs. DPU 18-5 (gas); DPU 18-6 (gas)). Based on these considerations and the foregoing analysis, the Department approves the Company's proposed R2.5-70 curve and resulting overall depreciation accrual rate of four percent for Account 376.

iii. Account 380 – Services - Gas

For Account 380, Unitil proposes a depreciation accrual rate of 6.21 percent based on an R3-45 curve (Exh. Unitil-NWA-3, at 51, 87 (gas)). As an alternative, the Attorney General proposes an accrual rate of 5.85 percent resulting from an L4-47 curve (Exh. AG-DJG-1, at 4, 21 (gas)). For this account, both proposed curves provide appropriate fits that balance the data points from both the longer and shorter experience bands (Exhs. Unitil-NWA-Rebuttal at 19 (gas); AG-DJG-1, at 21 (gas)). The Company states that its proposed curve is a closer fit to the more recent experience band, and that similar considerations should be given to this account as to Account 376 – Mains (Exh. Unitil-NWA-Rebuttal at 19-20 (gas)). Additionally, the Company maintains that the L-curve proposed by the Attorney General is unusual for this account because of its long tail (Exh. Unitil-NWA-Rebuttal at 19-20 (gas)). A review of other gas utility depreciation data shows that while both proposed curves are within the average range with respect to ASL, only R-curves and S-curves are used for this account (Exh. DPU 18-2, Att. (gas)). Based on these considerations, as well as the context of the energy transition and its potential impact on gas assets, the Department finds the Company's proposed curve-life combination to be prudent and reasonable (Exhs. Unitil-NWA-Rebuttal at 19-20 (gas); DPU 18-5 (gas); DPU 18-6 (gas); AG 3-12 (gas)). Therefore, the Department approves the Company's proposed R3-45 curve and corresponding depreciation accrual rate of 6.21 percent.

c. AMI Assets

As discussed in Section X. below, Unitil proposes a Company-specific AMI tariff consistent with the AMI implementation plan and model tariff approved in Second Grid Modernization. As set forth in Section X.B. below, the Department has determined the most prudent course of action is to recover all meter-related capital through the GMF. As such, the depreciation expense associated with meters (Account 370.10, Account 370.21, Account 370.22, and Account 370.30) was removed from base distribution rates (Exh. Sch. RevReq-4-2, at 2 (Rev. 4) (electric)).

d. Conclusion

Based on the analysis above, the Department finds that Unitil has appropriately calculated the depreciation expense for its electric and gas divisions. Therefore, the Department approves the Company's proposed depreciation accrual rates and the corresponding depreciation expense as proposed, with the exclusion of depreciation expense associated with AMI meters.

Accordingly, the Department approves rate-year depreciation expenses of $6,530,099 and $10,444,151 for the Company's electric and gas divisions, respectively.

F. Dues and Memberships

1. Introduction

The Company, through its service company USC, maintains memberships in various industry and non-industry trade associations and organizations (Exhs. DPU 16-5, Att. 1 (Rev.) (electric); AG 1-56, Att. 1 (Rev.) (electric); DPU 13-12, Att. 1 (Rev.) (gas); AG 1-56, Att. 1 (Rev.) (gas)). "Industry" memberships are specific only to the utility industry, and "non-industry" memberships refer to memberships not specific to the utility industry (see Exhs. DPU 16-5, Att. 1 (Rev.) (electric); DPU 29-3 (electric); DPU 13-12, Att. 1 Rev. (gas); DPU 24-9 (gas)).

Through USC, the Company's electric division maintains membership in the Edison Electric Institute ("EEI") as well as several other industry and non-industry related organizations (Exhs. DPU 16-1 & Atts. (Rev.) (electric); DPU 16-5, Att. 1 (Rev.) (electric); AG 1-56, Att. 1 (Rev.) (electric)).[97] Through USC, the Company's gas division maintains memberships in the American Gas Association ("AGA") and the Coalition for Renewable Natural Gas ("CRNG") as well as several other industry-related organizations and non-industry related organizations

97 USC allocates the EEI membership dues to its electric affiliates using the electric-only three-factor allocator detailed in its cost allocation manual (Exhs. DPU 16-1, Att. 2 (Rev.) (electric); AG 1-28, Att. 1, at 365 (electric)).

(Exhs. DPU 13-2, Att. 1 (gas); DPU 13-6, Att. 2 (gas); DPU 13-9, Att. 1 (gas); DPU 13-12, Att. 1 (Rev.) (gas); AG 1-56, Att. 1 (Rev.) (gas)).[98, 99]

During the test year, the Company booked $59,116 in dues and memberships to its electric division (Exh. AG 1-56, Att. 1 (Rev.) (electric)). The expense comprised $24,796 in EEI dues allocated from Unitil Corporation and $34,320 in costs allocated to the electric division from USC for a variety of industry and non-industry dues and memberships (Exhs. DPU 16-1, Att. 2 (Rev.) (electric); DPU 16-5, Att. 1 (Rev.) (electric); AG 1-56, Att. 1 (Rev.) (electric); Unitil-WP 1.3 (Rev. 4) (electric)). Of the $59,116 amount, the Company assigns 5.1021 percent to internal transmission, resulting in $56,100 of proposed distribution-related electric division test-year level of dues and memberships expense (see Exhs. Sch. RevReq-3-11 (Rev. 4) (electric); Unitil-WP 1.3 (Rev. 4) (electric)). Unitil proposed to remove $5,065 in EEI-related lobbying costs from the electric division's cost of service (Exhs. DPU 16-1, Att. 2 (Rev.) (electric); Sch. RevReq-3-11 (Rev. 4) (electric)). The Company assigned $258 of the adjustment to internal transmission for a proposed distribution-related adjustment of $4,807 (Exhs. Unitil-CGDN-10, at 2 (Rev. 4) (electric); Sch. RevReq-3-11 (Rev. 4) (electric)). The Company also proposed to remove $1,353 in additional costs allocated by USC from the electric

98 USC allocates certain gas-only industry membership dues (e.g., AGA, CRNG) to its gas affiliates using the gas-only three-factor allocator detailed in its cost allocation manual (Exhs. AG 1-28, Att. 1, at 365 (gas)). USC allocates additional membership dues through a three-factor allocator derived from a company's ratios of revenue, customers, and utility plant assets among all of its affiliates (Exhs. AG 1-28, Att. 1, at 30; Att. 3 n.1 (electric); AG 1-28, Att. 1, at 30; Att. 3 n.1 (gas)).

99 In all instances, each of the electric and gas divisions are allocated its portion of dues and membership expenses from USC or Unitil Corporation (see Exhs. DPU 16-1, Att. 1 (electric); DPU 13-2, Att. 1 (gas); DPU 13-9, Att. 1 (gas)).

division's cost of service (Exhs. DPU 16-5, Att. 1 (Rev.) (electric); Sch. RevReq-3-11 (Rev. 4) (electric)). The Company assigned $69 of this adjustment to internal transmission for a proposed distribution-related adjustment of $1,284 (Exhs. Unitil CGDN-10, at 2 (Rev. 4) (electric); Sch. RevReq-3-11 (Rev. 4) (electric)). Based on these proposed adjustments, the Company seeks to reduce the electric division's distribution-related test-year level of dues and memberships expense by $6,091, resulting in $50,009 of proposed distribution-related electric division test-year level of dues and memberships expense (Exhs. Unitil CGDN-10, at 2 (Rev. 4) (electric); Sch. RevReq-3-11 (Rev. 4) (electric)).

During the test year, the Company booked $84,875 in USC-allocated dues and memberships to its gas division (Exh. AG 1-56, Att. 1 (Rev.) (gas)). The expense comprised $59,713 in various dues and memberships for the gas division allocated from USC (including $19,796 in AGA membership dues and $10,395 in CRNG membership dues), and $25,162 in costs allocated to the gas division from USC for additional dues and memberships (Exhs. DPU 13-12, Att. 1 (Rev.) (gas); AG 1-56, Att. 1 (Rev.) (gas)). Unitil proposed to remove $1,010 in AGA-related lobbying costs (for an adjusted AGA total of $18,786); $6,615 in CRNG costs (for an adjusted CRNG total of $3,780); and $1,214 in costs allocated by USC (Exhs. Sch. RevReq-3-18 (Rev. 4) (gas); DPU 13-2 (gas); DPU 13-6 (gas); DPU 13-12, Att. 1 (Rev.) (gas)). Based on these proposed adjustments, the Company seeks to reduce the gas division's test-year level of dues and memberships expense by $8,839, resulting in $76,036 of proposed distribution-related gas division test-year level of dues and memberships expense (see Exhs. Unitil-CGDN-7, at 2 (Rev. 4) (gas); Sch. RevReq-3-18 (Rev. 4) (gas); DPU 13-2 (gas); DPU 13-12, Att. 1 (Rev.) (gas)).

On brief, the Company summarized its revised calculation of dues and membership expense (Company Brief at 212 (electric); Company Brief at 203-204 (gas)). No other party commented on this issue on brief.

2. Analysis and Findings

a. Non-Industry Dues

The Department requires that the Company demonstrate a link between non-industry dues and memberships and ratepayer benefits for the costs to be recoverable in rates. See, e.g., D.P.U. 92-111, at 127; Milford Water Company, D.P.U. 92-101, at 54 (1992); Berkshire Gas Company, D.P.U. 90-121, at 151 (1990). The Department asked the Company to provide justification for inclusion in its cost of service for each of its dues and memberships, and the Company's response was in the form of brief, general explanations, noting benefits such as offering insight, expertise, industry data, knowledge exchange, publications, and best practices that the Company uses to provide safe and reliable service (Exhs. DPU 16-5 (Rev.) (electric); DPU 13-2 (gas); DPU 13-6 (gas); DPU 13-9 (gas); DPU 13-12 (Rev.) (gas)). While the Department recognizes that some of these memberships may help provide insight to both electric and gas divisions on issues relevant to its business, the Company has not demonstrated that there is a clear link between the Company's memberships in the majority of the non-industry organizations and meaningful benefits to customers, or that these memberships are necessary to the provision of electric distribution service or gas distribution service to customers (Exhs. DPU 16-5 & Att. 1 (Rev.) (electric); DPU 13-12 & Att. 1 (Rev.) (gas)). As noted above, it is the Company's burden to establish that these non-industry dues and memberships benefit customers. See, e.g., D.P.U. 92-111, at 127; D.P.U. 92-101, at 54; D.P.U. 90-121, at 151.

Specifically, the Department finds that the Company sufficiently demonstrated direct and distinct benefits to ratepayers for one non-industry organization for which it seeks to recover dues and membership costs – the National Safety Council. The Company's membership on the National Safety Council provides it with information on eliminating the leading cause of preventable death and injuries and how to increase safety throughout the Company (Exhs. DPU 16-5, at 3 (Rev.) (electric); DPU 13-12, at 5 (Rev.) (gas)).

Based on the foregoing considerations, the Department allows recovery of the costs associated with membership in the National Safety Council, for which the Company demonstrated a clear link between costs and ratepayer benefits. The total cost proposed in the Company's cost of service for the National Safety Council is \$162 for the electric division, and \$119 for the gas division (see Exhs. DPU 16-5, Att. 1 (Rev.) (electric); DPU 13-12, Att. 1 (Rev.) (gas)). We disallow recovery of the costs associated with the remaining non-industry dues and memberships, as we conclude that it is inappropriate for ratepayers to fund the costs of non-industry dues and memberships for which the Company has not established a clear and direct link to ratepayer benefits on the record. D.P.U. 92-111, at 127; D.P.U. 92-101, at 54; D.P.U. 90-121, at 151; see also D.P.U. 22-22, at 211; D.P.U. 20-120, at 329-330. The Department calculates the disallowed dues and memberships as \$28,901 for the electric division and \$25,299 for the gas division (see Exhs. DPU 16-5, Att. 1 (Rev.) (electric); DPU 13-12, Att. 1 (Rev.) (gas)). Of the electric division amount, the Department calculates the portion assignable to internal transmission to be \$1,475.[100] The Department next will address the proposed

[100] \$28,901 x \$5.1021 percent = \$1,475 (see Exh. Sch. RevReq-3-11 (Rev. 4) (electric); Unitil-WP 1.3 (Rev. 4) (electric))

inclusion of industry-related dues and memberships in Unitil's cost of service for its electric and gas divisions.

b. Industry Dues

The Department is satisfied that customer benefits associated with the Company's industry-related dues and memberships are clear and discernable based on the record before us, with the exceptions discussed below (Exhs. DPU 16-5, Att. 1 (Rev.); DPU 13-2 (gas); DPU 13-6 (gas); DPU 13-9 (gas); DPU 13-12 (Rev.) (gas)). Thus, with the exceptions below, we allow recovery of the Company's industry-related dues and membership expenses.

In D.P.U. 20-80-B at 137, the Department set forth a regulatory framework for pursuing an energy future that moves the Commonwealth beyond gas. The Department not only prohibited the use of ratepayer funds for gas advertising and marketing by LDCs but also prohibited indirect efforts to promote either natural gas expansion or policies geared toward promoting natural gas expansion. D.P.U. 20-80-B at 57.[101]

As noted above, Unitil booked $19,796 to the gas division in test-year expense for AGA membership dues, and after removing $1,010 attributable to lobbying expenses, proposed an adjusted test-year expense of $18,786 (Exhs. Sch. RevReq-3-18 (Rev. 4) (gas); DPU 13-2 (gas); DPU 13-12, Att. 1 (Rev.) (gas)). The Company states that its membership in AGA provides ratepayer benefits because AGA: (1) conducts programs and develops standards to help enhance the safe delivery of natural gas; (2) advocates for natural gas industry issues, regulatory constructs, and business models that are priorities for the industry, such as safety and personnel

[101] In D.P.U. 20-80-B, the Department did not endorse a preferred decarbonization pathway or technology. D.P.U. 20-80-B at 35.

training; (3) facilitates the exchange of information and improvement of performance metrics; (4) helps members manage and respond to customer energy needs, regulatory trends, natural gas or capital market issues, and emerging technologies; and (5) collects, analyzes and disseminates information to opinion leaders, policy makers, and consumers about benefits provided by energy utilities and the natural gas industry (Exhs. DPU 13-2 (gas); DPU 13-12 (Rev.) (gas)). Further, the Company explained that AGA "educates the public about the importance of natural gas, supports natural gas utilities in their efforts to make their operations safer, more efficient and more environmentally-friendly, and serves as a resource for local, state and federal policymakers when it comes to regulating the natural gas industry" (Exh. DPU 41-6 (gas)). The Company states that because AGA's focus on the importance of safety, reliability, and security in the Company's provision of service to its customers, it does not consider its membership in the AGA to be promotional in nature (Exh. DPU 41-6 (gas)).

The Department recognizes that a portion of AGA membership dues provides ratepayer benefits through the organization's focus on safety, reliability, and security. The Department, however, is concerned by AGA's activities regarding its dissemination of information to consumers about the benefits provided by the natural gas industry. Thus, the Department considers Unitil's membership to be an indirect effort to promote natural gas expansion and, therefore, in conflict with the decarbonization goals of the Commonwealth. Without direct access to relevant financial information, the Department cannot separate the portion of the Company's AGA membership dues devoted to the promotion of natural gas and or natural gas expansion from the portion of AGA dues expense that support activities that are beneficial to ratepayers (i.e., support the safe and reliable delivery of natural gas to customers)

(Exh. DPU 41-6 (gas)). See D.P.U. 88-135/151, at 57. As such, the Department disallows the recovery of $18,786 in AGA membership dues for the gas division.

As noted above, the Company proposed to remove $6,615 in CRNG membership dues from the gas division's cost of service (Exhs. Sch. RevReq-3-18 (Rev. 4); DPU 13-6 (gas)). There remains in the proposed cost of service $3,780 in CRNG membership dues for the gas division (Exhs. Sch. RevReq-3-18 (Rev. 4) (gas); DPU 13-6 (gas); AG 1-56, Att. 1 (Rev.)). The Company states that CRNG is dedicated to the sustainable advancement of renewable natural gas ("RNG") as clean alternative and domestic energy resource and advocates and educates for the development, deployment, and utilization of RNG (Exh. DPU 13-6 (gas)). Unitil states that its CRNG membership provides educational information on RNG developments and helps the Company investigate and better understand the sustainable development, deployment, and utilization of RNG (Exhs. DPU 13-6 (gas); DPU 13-12 (Rev.) (gas)). In D.P.U. 20-80-B at 68, 70, the Department shared the concerns raised by various stakeholders in that proceeding regarding costs, availability, and the treatment of renewable fuels as carbon neutral, and has recognized that RNG is currently more expensive than conventional natural gas. As such, the Department found that RNG does not meet the DPU's least-cost supply planning standards. D.P.U. 20-80-B at 68-69. Further, in that proceeding, the Department declined to alter our existing gas procurement policy as established in Commonwealth Gas Company, D.P.U. 94-174-A (1996) to allow for the acquisition of RNG. D.P.U. 20-80-B at 69. In addition, the Department recognized that the use of RNG and hydrogen as fuel are new, unproven, and uncertain technologies that have not yet been proven to lead to a net reduction in GHG emissions. D.P.U. 20-80-B at 68, 71-72. As such, based on record evidence in the instant proceeding, and the current state of RNG as a natural gas alternative, we find that the Company has not demonstrated a direct link between its CRNG membership dues and ratepayer benefits. Accordingly, the Department disallows the recovery of $3,780 in CRNG membership dues for the gas division.

c. Conclusion

As noted above, the Company proposed to reduce its distribution-related test-year dues and memberships expense for the electric division by $6,091. Based on the above findings, the Department further reduces the Company's cost of service by $28,901, and assigns $1,475 to internal transmission, which results in a net reduction of $27,426 to distribution-related test-year dues and memberships expense for the electric division. Similarly, as noted above, the Company proposed to reduce its test-year dues and memberships for the gas division by $8,839. Based on the findings above, the Department further reduces the Company's cost of service by $47,865.[102]

G. Property and Liability Insurance

1. Introduction

Unitil's property and liability insurance program is company-wide (i.e., premiums cover both the electric division and the gas division) and includes both premium-based and self-insured coverage (Exhs. Unitil-CGDN-1, at 31, 41 (electric); Unitil-WP 5.1 (Rev. 4) (electric); Unitil-CGDN-1, at 29, 36 (gas); Unitil-WP 4.1 (Rev. 4) (gas)). The Company's premium-based insurance includes coverage for all risk, crime, kidnapping and extortion, workers'

[102] The disallowed costs comprise AGA membership dues of $18,786, CRNG Inc. membership dues of $3,780, and non-industry dues of $25,299 (Exhs. DPU 13-2 (gas); DPU 13-6 (gas); DPU 13-12, Att. 1 (Rev.) (gas)).

compensation, excess liability, automobile, directors and officers, cyber, and fiduciary (Exh. Unitil-WP 5.2 (Rev. 4) (electric)). The premium-based insurance costs are incurred by USC and subsequently allocated among the various affiliates, including the Company (Exhs. AG 1-61, at 1 (electric); Unitil-WP 5.2 (Rev. 4) (electric); Unitil-WP 4.2 (Rev. 4) (gas)). This process resulted in an allocation to the Company of 15.14 percent to the electric division and 11.10 percent to the gas division during the test year (Exhs. Unitil-WP 5.2 (Rev. 4) (electric); Unitil-WP 4.2 (Rev. 4) (gas); DPU 28-1 (electric); AG 1-61, at 1).

During the test year, the Company booked $221,772 in premium-based property and liability insurance expense to its electric division (Exh. Sch. RevReq-3-8 (Rev. 4) (electric)).[103] Unitil's final electric division adjustment reflects a proposed increase to test-year expense of $74,596 (Exh. Sch. RevReq-3-8 (Rev. 4) (electric)).[104] The Company booked $186,345 in premium-based property and liability insurance expense to its gas division in the test year (Exh. Sch. RevReq-3-11 (Rev. 4) (gas)).[105] Unitil's final gas division adjustment reflects a proposed increase to test-year expense of $60,413 (Exh. Sch. RevReq-3-11 (Rev. 4) (gas)).

To derive its proposed increases for premium-based property and liability insurance, the Company summed actual costs for 2023 and, where available 2024, and calculated the difference between that amount and the test-year amount (Exhs. Unitil-CGDN-1, at 31-32 (electric);

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103 The test-year costs include $195,386 in direct costs and $26,386 allocated from USC (Exh. Sch. RevReq-3-8 (Rev. 4) (electric)).

104 Of this amount, $3,806 is assigned to internal transmission and the remaining $70,790 is assigned to base distribution (Exhs. Unitil-CGDN-1, at 31 (electric); Sch. RevReq-3-8 (Rev. 4) (electric)).

105 The test-year costs include $168,716 in direct costs and $17,630 allocated from USC (Exh. Sch. RevReq-3-11 (Rev. 4) (gas)).

Sch. RevReq-3-8 (Rev. 4) (electric); Unitil-WP 5.3 (Rev. 4) (electric); Unitil-CGDN-1, at 29 (gas); Sch. RevReq-3-11 (Rev. 4) (gas); Unitil-WP 4.3 (Rev. 4) (gas); DPU 1-1 (Rev.) & Atts.).

Unitil argues that its property and liability insurance expenses are reasonable and appropriate (Company Brief at 215-217 (electric); Company Brief at 182-184 (gas)). No other party addressed this issue on brief.

2. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expenses based on a historic test year adjusted for known and measurable changes. D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. To be included in rates, property and liability insurance expenses must be reasonable. See D.T.E. 02-24/25, at 161-162. Further, companies must demonstrate that they have acted to contain their property and liability insurance costs in a reasonable and effective manner. D.P.U. 10-55, at 276; D.P.U. 08-35, at 119-120; D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185. Finally, any post-test-year adjustments to property and liability insurance expense must be known and measurable. D.P.U. 09-30, at 218; D.T.E. 02-24/25, at 161; D.P.U. 86-86, at 8-10; Colonial Gas Company, D.P.U. 84-94, at 44 (1984).

Based on a review of the Company's process for securing premium-based insurance coverage, the Department finds that Unitil has acted to contain its property and liability insurance costs in a reasonable and effective manner (Exhs. Unitil-CGDN-1, at 32-33 (electric); Unitil-CGDN-1, at 30-31 (gas)). Further, Unitil has provided updated policy cost information and explanations for increases in premiums for workers' compensation, excess liability, automobile, and cyber (Exhs. DPU 1-1 & (Rev.) & Atts.; Unitil-WP 5.2 (Revs. 2, 3) (electric);

Unitil-WP 4.2 (Rev. 3) (gas); Tr. 4, at 436-442). The Department finds that the test-year level and the proposed increases to the test-year level of expenses are reasonable and known and measurable. Accordingly, the Department accepts the Company's proposed insurance premium expenses.

H. Self-Insurance Normalization

1. Introduction

The Company relies on self-insurance for the following types of property and liability risks: (1) medical, dental, and vision insurance benefits up to $200,000 in claims for each family unit; (2) general liability up to $1,000,000 per claim; and (3) directors and officers liability up to $750,000 per claim (Exh. AG 1-63, at 1). During the test year, Unitil's electric division incurred $2,281 in net cash disbursements for general liability claims (Exh. Sch. RevReq-3-12 (Rev. 4) (electric)). The Company generated a five-year average of net cash disbursement for general liability claims from 2018 through 2022 to compute an average annual self-insurance expense of $5,527 (Exh. Sch. RevReq-3-12 (Rev. 4) (electric)). This amount, less the test-year expense of $2,281, yields a proposed adjustment of $3,246 (Exhs. Unitil-CGDN-1, at 41; Sch. RevReq-3-12 (Rev. 4) (electric)).[106] Similarly, Unitil computed a five-year average of gas division net cash disbursements of $3,084 (Exh. Sch. RevReq-3-14 (Rev. 4) (gas)). This amount, less the test-year expense of $758, yields the proposed adjustment of $2,326 (Exhs. Unitil-CGDN-1, at 36; Sch. RevReq-3-14 (Rev. 4) (gas)).

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[106] Of this amount, $166 was assigned to internal transmission and $3,080 was assigned to base distribution service (Exhs. Unitil-CGDN-1, at 41; Sch. RevReq-3-12 (Rev. 4) (electric)).

Unitil argues that it has appropriately calculated its self-insurance expense in accordance with Department precedent by applying a five-year average expense (Company Brief at 230 (electric); Company Brief at 195 (gas)). No other party addressed this issue on brief.

2. Analysis and Findings

The Department has recognized that because self-insured damage claims vary from year to year, limiting recovery to test-year levels may not produce a representative level of claims expense on a forward-looking basis. See D.P.U. 87-59, at 35 40. Accordingly, the Department has used a five-year average of self-insurance claim payments to determine the appropriate level of self-insured expense for ratemaking purposes. D.P.U. 13-90, at 106; D.P.U. 09-30, at 219-220; D.P.U. 89-194/195, at 75.

Unitil's use of a five-year average of actual self-insured damage claims paid is consistent with Department precedent. D.P.U. 15-80/D.P.U. 15-81, at 158; D.P.U. 13-90, at 106. Further, we are satisfied that the Company's calculations produce a representative level of self-insurance expense for the electric and gas divisions (Exhs. Sch. RevReq-3-12 (Rev. 4) (electric); Sch. RevReq-3-14 (Rev. 4) (gas); AG 4-35). Accordingly, the Department accepts the Company's proposed self-insurance expense.

I. Protected Receivables Expense

1. Introduction

Active Hardship Protected Accounts ("AHPA") are residential accounts that are protected from shut-off by the utility for nonpayment. 220 CMR 25.03, 25.05. To qualify for protected status from service termination, customers must demonstrate that they have a financial hardship and meet certain other requirements, such as suffering from a serious illness or residing with a child under twelve months of age. 220 CMR 25.03(1); 220 CMR 25.03(3); 220 CMR 25.05(3).[107] All qualified accounts are protected from shut-off for nonpayment year-round. In addition, heating accounts are protected from shut-off for nonpayment during the winter moratorium period, November 15 through March 15. 220 CMR 25.03(1)(a)(3), 25.03(1)(b). In the Company's last base distribution rate case for its electric and gas divisions, the Department allowed the recovery of an amount of amortization expenses associated with these accounts that had been outstanding over 360 days as of the end of the test year in those cases (i.e., December 31, 2018) (Exhs. Unitil-CGDN-1, at 41 (electric); Unitil-CGDN-1, at 31 (gas)). D.P.U. 19-130, at 6; D.P.U. 19-131, at 6.

In the instant case, the Company proposes to recover the December 31, 2022, incremental increase in amortization expense for uncollectible past due AHPA over the amounts that were approved in D.P.U. 19-130 and D.P.U. 19-131 (Exhs. Unitil-CGDN-1, at 41-42 (electric); Unitil-CGDN-1, at 36-37 (gas)). For the electric division, Unitil's stated AHPA balance as of test-year end 2022 is $2,843,577, which the Company seeks to amortize over five years, or $568,715 annually (Exhs. Unitil-CGDN-1, at 41-42; Unitil-CGDN-4 (electric); Sch. RevReq-3-13 (Rev. 4) (electric); AG 4-38 (electric); AG 4-40 (electric)). For the gas

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107 Pursuant to Department regulations, an account qualifies for protected status where the customer certifies that the customer has a financial hardship, and: (1) a person residing in the household is seriously ill; (2) a child under the age of twelve months resides in the household; (3) the customer takes heating service between the period November 15 and March 15, and the service has not been shut off for nonpayment prior to November 15; or (4) all adults residing in the household are age 65 or older and a minor resides in the household. 220 CMR 25.03. Customers who are unable to pay an overdue bill and meet the income eligibility requirements for the Federal Low-Income Home Energy Assistance Program are deemed to have a financial hardship. 220 CMR 25.01(2).

division, Unitil's stated AHPA balance as of test-year end is $1,084,427, which the Company seeks to amortize over five years, or $216,885 annually (Exhs. Unitil-CGDN-1, at 36-37; Unitil-CGDN-4 (gas); Sch. RevReq-3-15 (Rev. 4) (gas); AG 4-37 (gas); AG 4-39 (gas)). For both the electric and gas divisions, the Company proposes that any future payments made by customers towards the amortized balance would be credited to the Company's Residential Assistance Adjustment Factor ("RAAF") (Exhs. DPU 27-1 (electric); DPU 21-1 (gas)).

Unitil argues that it has appropriately calculated its protected receivables expense in accordance with Department precedent (Company Brief at 230-233 (electric); Company Brief at 195-198 (gas)). No other party addressed this issue on brief.

2. Analysis and Findings

The Department has previously found that the growing balance of hardship protected accounts receivable was the result of several factors, including public policy decisions and economic conditions. D.P.U. 15-80/D.P.U. 15-81, at 170-171; D.P.U. 13-90, at 163-164; D.P.U. 10-70, at 214-215. After considering these factors, the Department determined that a remedy was warranted because the financial impact of the growing balance of hardship protected accounts receivable could have unfavorable consequences not only for a company's shareholders but also for a company's ratepayers. D.P.U. 15-80/D.P.U. 15-81, at 171; D.P.U. 13-90, at 164; D.P.U. 10-70, at 215-216. Thus, in recent base distribution rate cases, the Department has allowed Unitil to recover the outstanding balance of hardship protected accounts receivable over 360 days past due at the end of the respective test year. D.P.U. 19-130, at 6; DPU. 19-131, at 6; D.P.U. 15-80/D.P.U. 15-81, at 171-172.

We find that the same factors that impacted our decisions in D.P.U. 15-80/D.P.U. 15-81, D.P.U. 13-90, and D.P.U. 10-70 still exist. Specifically, the public policy decisions that extended protections from service terminations for hardship accounts as well as an easing of the eligibility requirements for the Federal Low-Income Home Energy Assistance Program. See, e.g., An Act Relative to Heating Energy Assistance and Tax Relief, St. 2005, c. 140, § 12, amending G.L. c. 164, § 1F; Investigation Commencing a Rulemaking Pursuant to 220 C.M.R. § 2.00 et seq., D.P.U. 08-104-A (2009); Emergency Rulemaking, D.T.E. 05-87 (2005) (see also Exhs. DPU 4-3 (electric); DPU 4-3 (gas); AG 4-37 (gas)). Further, we accept the Company's test-year end 2022 AHPA balances and calculation of incremental increases in the AHPA balances for test-year-end 2022 (Exhs. Unitil-CNDG-4 (electric); Unitil-CNDG-4 (gas); DPU 4-3 (electric); DPU 4-3 (gas); AG 4-38 (electric); AG 4-37 (gas)). Thus, we approve the recovery of the Company's outstanding balance of hardship protected accounts receivable for its electric and gas divisions.

As noted above, the Company proposes to amortize the incremental AHPA balances over a five-year period (Exhs. Unitil-CGDN-1, at 41-42 (electric); Unitil-CGDN-4 (electric); Sch. RevReq-3-13 (Rev. 4) (electric); AG 4-40 (electric); Unitil-CGDN-1, at 36-37 (gas); Unitil-CGDN-4 (gas); Sch. RevReq-3-15 (Rev. 4) (gas); AG 4-39 (gas)). Amortization periods are determined on a case-by-case review of the evidence and underlying facts. Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 99 (2009); Barnstable Water Company, D.P.U. 93-223-B at 14 (1993); D.P.U. 84-145-A at 54. In determining the proper length for the amortization period, the Department must balance the interests of both the Company and its ratepayers. D.P.U. 93-223-B at 14. In setting the length of an amortization period, the

Department has considered such factors as the amount under consideration for deferral, the value of such an amount to ratepayers based on certain amortization periods, and the impact of the adjustment on the Company's finances and income. D.P.U. 08-27, at 99; D.P.U. 93-223-B at 14.

In the instant case, we consider the size of the balance to be recovered, the underlying facts giving rise to the accumulation of the balance, and the impact of recovery on ratepayers. Based on these considerations and the record in this case, the Department finds that five years is an appropriate amortization period (Exhs. Unitil-CGDN-1, at 41-42 (electric); Unitil-CGDN-4 (electric); Sch. RevReq-3-13 (Rev. 4) (electric); AG 4-40 (electric); Unitil-CGDN-1, at 36-37 (gas); Unitil-CGDN-4 (gas); Sch. RevReq-3-15 (Rev. 4) (gas); AG 4-39 (gas)). D.P.U. 15-80/D.P.U. 15-81, at 172; D.P.U. 10-70, at 220. The Company is directed to credit all future payments received for the electric division and gas division through each division's respective RAAF. D.P.U. 15-80/D.P.U. 15-81, at 171-172; D.P.U. 14-150, at 382. Finally, we direct the Company, for the electric division and the gas division, to track the accounts included in the balance of hardship protected accounts allowed for recovery so that the associated costs are excluded from recovery through bad debt expense. Based on the foregoing, the Department approves the Company's proposal to recover incremental amortization expense for uncollectible past due AHPA over five years, in the annual amount of $568,715 for the electric division and $216,885 for the gas division.

J. Uncollectible Expense

1. Introduction

A distribution company recovers uncollectible expense (i.e., bad debt) associated with both commodity ("supply-related bad debt") and retail distribution service ("distribution-related bad debt"). See, e.g., D.P.U. 07-71, at 106. The Company's electric division has been recovering supply-related bad debt on a dollar-for-dollar basis through its Basic Service Costs Adder since December 1, 2005. D.P.U. 07-71, at 106-109; Fitchburg Gas and Electric Light Company, D.T.E. 05-GAF-P4/06-28, Order on Remand at 30 (2015). Unitil's gas division has been recovering supply-related bad debt on a dollar-for-dollar basis pursuant to its Cost of Gas Adjustment Clause tariff since January 1, 2006. Fitchburg Gas and Electric Light Company, D.T.E. 06-109, at 4 (2007); D.T.E. 05-GAF-P4/06-28, Order on Remand at 30.

Regarding distribution-related bad debt, the Department permits a representative level of bad debt expense to be included in cost of service. D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. During the test year, Unitil booked $1,064,382[108] and $762,747 to distribution-related uncollectible expense for its electric and gas divisions, respectively (Exhs. Sch. RevReq-3-9 (Rev. 4) (electric); Sch. RevReq-3-12 (Rev. 4) (gas)). The Company proposes to increase its distribution-related bad debt expense by $138,892[109] for its electric division and by $387,626[110] for its gas division (Exhs. Sch. RevReq-3-9 (Rev. 4) (electric);

[108] The Company's test-year distribution-related bad debt expense for the electric division is exclusive of $15,089 in bad debt expense assigned to internal transmission (Exh. Sch. RevReq-3-9 (Rev. 4) (electric)). To determine the amount assigned to internal transmission, the Company multiplied the proposed uncollectible distribution revenue requirement of $1,079,471 by the Company's internal transmission allocator of 1.3978 percent) (Exh. Sch. RevReq-3-9 (Rev. 4) (electric)).

[109] The Company's proposed increase to its distribution-related bad debt expense for the electric division is exclusive of $1,969 in expense assigned to internal transmission (Exh. Sch. RevReq-3-9 (Rev. 4) (electric)).

[110] Test-year delivery retail billed revenue was normalized for the revenue increase calculated in this rate case (Exhs. Sch. RevReq-3-9 (Rev. 4) (electric); Sch. RevReq-3-12 (Rev. 4) (gas)).

Sch. RevReq-3-12 (Rev. 4) (gas)). For both the electric and gas divisions, the Company proposes to calculate the total amount of distribution-related bad debt to be included in distribution rates by dividing the three-year average (i.e., 2020 through 2022) distribution-related net write-offs by the distribution-related revenues for the same period and multiplying the resulting percentage by the sum of normalized test-year distribution revenue and the proposed total increase to base distribution revenue for each division (Exhs. Unitil-CGDN-1, at 33-34 (electric); Sch. RevReq-3-9 (Rev. 4) (electric); Unitil-CGDN-1, at 31 (gas); Sch. RevReq-3-12 (Rev. 4) (gas)).

Unitil argues that it has taken a variety of steps to control its distribution-related bad debt expense and that it has appropriately calculated its distribution-related bad debt expense consistent with Department precedent (Company Brief at 217-219 (electric); Company Brief at 184-186 (gas)). No other party addressed this issue on brief.

2. Analysis and Findings

The Department permits companies to include for ratemaking purposes a representative level of bad debt revenues as an expense in cost of service. D.P.U. 09-39, at 164; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 138-140. The Department has found that the use of the most recent three years of available data is appropriate in the calculation of bad debt. D.P.U. 96-50 (Phase I) at 71. When a company is allowed dollar for dollar recovery of bad debt expense associated with supply, the appropriate method to calculate distribution-related bad debt is to remove all revenues relating to supply from the company's bad debt calculations. D.P.U. 07-71, at 106-109.

For the electric division, applying the three-year average bad debt rate of 3.86 percent to the sum of normalized test-year distribution revenues, inclusive of internal transmission of $26,450,094 and the proposed total increase to base distribution revenue of $5,142,340, for a total of $31,592,434, yields a distribution-related bad debt expense of $1,220,332. Removing the 1.3978 percent of bad debt that is allocated to internal transmission reduces distribution-related bad debt expense for the electric division by $17,058 to $1,203,274. This results in an increase of $138,892 from the test-year delivery expense, absent the amount allocated to internal transmission, of $1,064,382 (Exh. Sch. RevReq-3-9 (Rev. 4) (electric)).

For the gas division, applying the three-year average bad debt rate of 3.53 percent to normalized test-year distribution revenues of $21,388,937, and the proposed increase to base distribution revenue of $11,227,825, for a total of $32,616,762 yields a distribution-related bad debt expense of $1,150,373. This results in an increase of $387,626 from the test-year delivery expense of $762,747 (Exh. Sch. RevReq-3-12 (Rev. 4) (gas)).

The Department has reviewed the Company's bad debt calculations, and the material supporting the calculations for both its electric and gas divisions (Exhs. Unitil-CGDN-1, at 33-34; Sch. RevReq-3-9 (Rev. 4) (electric); Unitil-CGDN-1, at 31; Sch. RevReq-3-12 (Rev. 4) (gas)). D.P.U. 07-71, at 106-109; D.P.U. 96-50 (Phase I) at 70-71; D.P.U. 89-114/90-331/91-80 (Phase One) at 137-140. The Department concludes that the method used by the Company to calculate its uncollectible expense adjustment for both its electric and gas divisions is consistent with Department precedent. D.P.U. 15-155, at 179-181; D.P.U. 09-39, at 164; D.P.U 07-71, at 106-109. The Company, however, applied the three-year average bad debt rate to both the test-year billed revenues and the requested distribution rate increase (Exhs. Sch. RevReq-3-9

(Rev. 4) (electric); Sch. RevReq-3-12 (Rev. 4) (gas)). Because the Department has not approved the distribution rate increase as proposed, the Company's proposed bad debt adjustment will be modified accordingly. D.P.U. 15-80/D.P.U. 15-81, at 161-162. The Department presents the approved bad debt adjustments in the division-specific Schedule 2 below.

K. Service Company Facilities Lease Expense

1. Introduction

USC provides centralized administrative, corporate, accounting, financial, engineering, information systems, customer support, regulatory, planning, energy procurement, and management services to the Company's electric and gas divisions (Exhs. Unitil-CGDN-1, at 5 (electric); Unitil-CGDN-1, at 5 (gas); AG 1-28, Att. 1, at 19). These services include direct charges billed for costs incurred and work performed by service company personnel directly related to the respective subsidiary, and common costs (i.e., indirect costs), which are allocated among the respective subsidiaries receiving the service based on appropriate allocation factors (Exhs. Unitil-CGDN-1, at 5-6 (electric); Unitil-CGDN-1, at 5 (gas)).

Unitil's service company facilities lease expense represents charges billed by USC to the Company for leased facilities (Exhs. AG 4-50 (electric); AG 4-45 (gas)). Unitil's electric and gas divisions are allocated lease expense for facilities located in Hampton, New Hampshire ("Liberty Lane"), Concord, New Hampshire ("McGuire Street"), Exeter, New Hampshire ("Energy Way"), and Portsmouth, New Hampshire ("Portsmouth") (Exhs. AG 1-28, Att. 1, at 16-17; Unitil-WP 7.3 (Rev. 4) (electric); Unitil-WP 5.3 (Rev. 4) (gas)). In addition, Unitil's gas division is allocated lease expense for its training facility located in Kensington, New Hampshire ("Training Facility") (Exhs. Unitil-CGDN-7, Att. 3, at 2 (Rev. 4) (gas); DPU 18-13, Att. 2 (Rev.) (gas); Sch. RevReq-3-18, line 5 (Rev. 4) (gas)). Unitil states that it is not a party to any of the lease agreements (Exhs. AG 4-50 (electric); AG 4-45 (gas); Tr. 9, at 878-879).

With the exception of the Portsmouth facility, which is owned by Northern Utilities, and the Liberty Lane building, which is owned by URC, all service company facilities are owned by UES, which leases the facilities to URC, which then subleases to USC based on square footage (Exhs. DPU 50-16, Att. 2, at 3, Att. 4, at 3 (electric); DPU 39-3, Att. 2, at 3, Att. 4, at 3 (gas)). USC then bills its affiliated companies, including the Company's electric and gas divisions, their respective pro-rated share of costs including depreciation and a return component based on UES's and/or URC's capital structure and rate of return (Exhs. DPU 50-16, Atts. 2, 4. (electric); DPU 39-3, Atts. 2, 4 (gas); AG 1-28, Att. 1, at 15, 17, 271, 280, 294; AG 4-50 (electric); AG 4-45 (gas)).

For the Portsmouth facility, Northern Utilities leases the facility to USC based on square footage, which then bills its affiliated companies, including the Company's electric and gas divisions, their respective prorated share of costs including depreciation and a return component based on Northern Utilities' capital structure and rate of return (Exhs. DPU 50-14, Att. 1 (electric); DPU 50-16, Att. 3, at 1-2, 6 (electric); DPU 39-3, Att. 3, at 1-2, 6 (gas); AG 1-28, Att. 1, at 287). For the Liberty Lane building, URC leases the facility to USC in its entirety, which then bills its affiliated companies, including the Company's electric and gas divisions, their respective pro-rated share of costs including depreciation and a return component based on URC's capital structure and rate of return (Exhs. DPU 50-16, Att. 1, at 1-2, 5 (electric); DPU 39-3, Att. 1, at 1-2, 5 (gas); AG 1-28, Att. 1, at 294).

USC bills the Company's electric and gas divisions by allocating facilities costs according to each division's share of USC's total indirect labor and overhead costs (Exh. AG 1-28, Att. 3 n.3). The methods used by Unitil to allocate USC indirect labor and overhead are detailed in the service company's cost allocation manual and most rely on a modified Massachusetts formula that USC refers to as a "3-factor" allocator, which is derived from a company's ratio of revenue, customers, and utility plant assets (Exhs. AG 1-28, Att. 1, at 30, Att. 3 n.1; Unitil-WP Allocators (Rev. 4) (electric); Unitil-WP Allocators (Rev. 4) (gas)).[111]

The Company proposes an adjustment to its gas division test-year facilities rent expense related to the inclusion of the gas division Training Facility (Exhs. Unitil-CGDN-1, at 41 (gas); Sch. RevReq-3-18 (Rev. 4) (gas)). The Company states that it received a temporary certificate of occupancy for the Training Facility on December 21, 2023, and the facility has been in continuous use since January 8, 2024 (Tr. 9, at 930-931). The Training Facility received its final certificate of occupancy from the town of Kensington on January 10, 2024 (Exh. ` (2/1/24) (gas)). The Training Facility is owned by UES, which leases the facility to URC, which is then subleased to USC (Exh. DPU 18-13, Att. 1, at 1, Att. 3, at 1 (gas); Tr. 9, at 878-879). USC then allocates the share of costs including depreciation and a return component to its affiliated

111 The Massachusetts formula is a three-part allocator that uses a weighted cost average ratio comparing gross revenues, plant, and payroll. D.P.U. 08-27, at 85 n.47. The Commonwealth originally developed the Massachusetts formula in 1919 for the purpose of apportioning income tax liabilities for companies with multi-state operations. Acts of 1919, c. 355, § 19. Since that time, regulatory commissions across the United States have used this general approach and variations thereof, including modified Massachusetts formulas, to apportion common costs among utility companies that operate in multiple jurisdictions. D.P.U. 08-27, at 85-86 n.47.

companies based on a headcount of each affiliate's share of the total training staff (Exhs. Unitil-CGDN-7, Att. 3, at 3 (Rev. 4) (gas); RR-DPU-48 (gas); Tr. 9, at 878-879). In USC's sublease of the Training Facility, USC pays a return component to URC, which then pays a return component to UES (Exhs. DPU 18-13, Att. 2 (Rev.), at 1 (gas); Unitil-CGDN-7, Att. 3, at 1-2 (Rev. 4) (gas)).

During the test year, Unitil's electric division booked $309,777 in service company facilities lease expense associated with depreciation and a return on facilities (Exhs. Unitil-WP 7.3 (Rev. 4) (electric); DPU 50-16 & Atts. (electric)). Also, during the test year, Unitil's gas division booked $227,115 in service company facilities lease expense associated with depreciation and a return on facilities (Exhs. Unitil-WP 5.3 (Rev. 4) (gas); DPU 39-3 & Atts. (gas)). In addition, the Company made a post-test-year adjustment of $127,842 to its gas division service company facilities lease expense related to the inclusion of the Training Facility lease expense and associated with depreciation and a return component to URC and UES (Exhs. Sch. RevReq-3-18, line 5 (Rev. 4) (gas); Unitil-CGDN-7, Att. 3, at 1 (Rev. 4) (gas); DPU 18-13, Att. 2, at 1-2 (Rev.) (gas)).[112]

2. Positions of the Parties

The Company asserts that it has met the Department's standard for inclusion of lease expense (Company Brief at 199-200 (gas), citing D.P.U. 19-120, at 263). Further, Unitil maintains that the Training Facility, which is used by the Company's gas division and employees

112 The allocation for Unitil's electric division is 15.14 percent, while for its gas division is 11.10 percent (Exhs. Unitil-WP 7.3 (Rev. 4) (electric); Unitil-WP 5.3 (Rev. 4) (gas); Unitil-WP Allocators (Rev. 4) (electric); Unitil-WP Allocators (Rev. 4) (gas)).

assigned to New Hampshire and Maine affiliates, is a permanent and dedicated space for training and operator qualification testing that is necessary to ensure the Company has a well-trained and qualified workforce to ensure public safety (Company Brief at 200-201 (gas), citing Exhs. Unitil-CGDN-1, at 41 (gas); DPU 18-13 (gas)). Finally, the Company asserts that the Training Facility has been in continuous use since January 8, 2024, and a final certificate of occupancy for the Training Facility was issued on January 10, 2024 (Company Brief at 202 (gas), citing Exh. Unitil-2 (2/1/24) (gas); RR-DPU-48 (gas); Tr. 9, at 930-931; Tr. 11, at 1131-1132). No other party addressed these issues on brief.

3. Analysis and Findings

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. D.P.U. 10-55, at 268; D.P.U. 09-39, at 155; D.T.E. 03-40, at 171; Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1989). The standard for inclusion of lease expense is one of reasonableness. D.P.U. 89-114/90-331/91-80 (Phase One) at 96. Known and measurable increases in rental expense based on executed lease agreements with unaffiliated landlords are recognized in cost of service as are operating costs (e.g., maintenance, property taxes) covered by the lessee. D.P.U. 95-118, at 42 n.24; Boston Gas Company, D.P.U. 88-67 (Phase I) at 95-97 (1988).

The Department permits rate recovery of payments to affiliates where these payments are: (1) for services that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a method that is both cost-effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 19-120, at 272; D.P.U. 17-05, at 162; D.P.U. 15-155, at 270-271; D.P.U. 13-75, at 184. In addition, 220 CMR 12.04(3) provides that: "An affiliated Company may sell, lease, or otherwise transfer an asset to a Distribution Company, and may also provide services to a Distribution Company, provided that the price charged to the Distribution Company is no greater than the market value of the asset or service provided."

The Company has provided lease and sublease agreements between affiliates for the various facilities (Exhs. DPU 50-16, Att. 1 (electric); DPU 18-13, Atts. 1, 3 (gas); DPU 39-1, Att. 1 (gas); AG 1-28, Att. 1, at 127-134, 140-141, 143-150, 170-177, 181-182). These facilities lease expense are related to corporate headquarters, office space, call centers, and a gas division training facility (Exhs. Unitil-CGDN-1, at 41-42 (gas); AG 1-28, Att. 1, at 17; AG 4-50 (electric); AG 4-45 (gas)). The Department finds that the proposed inclusion of facilities lease expense in the Company's cost of service is reasonable (Exhs. Unitil-WP 7.3 (Rev. 4) (electric); DPU 50-16 & Atts. (electric); AG 1-28, Att. 1, at 30; Unitil-CGDN-1, at 41-42 (gas); Unitil-CGDN-7, Att. 3 (Rev. 4) (gas); Unitil-WP 5.3 (Rev. 4) (gas); DPU 39-3 & Atts. (gas); DPU 18-13, Att. 2. (Rev.) (gas); DPU 18-13, Atts. 1, 3 (gas); AG 4-50 (electric); AG 4-45 (gas)).[113]

Further, the Department has previously found that services that USC provides to Unitil are necessary to the Company's business and, therefore, specifically benefit ratepayers.

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113 The Department notes that the attachments for Exhibits DPU 50-16 (electric) and DPU 39-3 (gas) were inadvertently mislabeled as Exhibits AG 50-16 and AG 39-3, respectively.

D.P.U. 11-01/D.P.U. 11-02, at 317. With the exception of the gas division Training Facility, all service company leases are allocated based on the Company's indirect labor and overhead allocators detailed in USC's cost allocation manual (Exhs. Unitil-WP 7.3 (Rev. 4) (electric); Unitil-WP Allocators (Rev. 4) (electric); AG 1-28, Att. 1, at 30; Att. 3 n.1; Unitil-CGDN-7, Att. 3, at 3 (Rev. 4) (gas); Unitil-WP 5.3 (Rev. 4) (gas)); Unitil-WP Allocators (Rev. 4) (gas); RR-DPU-48 (gas)). The Department finds that the rent expenses allocated to Unitil represent activities that specifically benefit ratepayers and do not duplicate services already provided by the Company (Exhs. Unitil-CGDN-1, at 41-42 (gas); AG 1-28, Att. 1). Finally, the Department finds the Training Facility's allocation method based on the gas division's share of technicians who require operator qualification training to be both cost-effective and nondiscriminatory for services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 20-120, at 278; D.P.U. 19-120, at 263.

The Department, however, has previously found that where a petitioning company pays a return component on a facility owned by an affiliate, customers of the petitioning company may be forced to subsidize the operations of the affiliate. D.P.U. 18-150, at 270; D.P.U. 17-05, at 220; D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 82-83. As such, the Department has limited the return component to the weighted average cost of capital ("WACC") applicable to the petitioning company. D.P.U. 18-150, at 270-271; D.P.U. 17-05, at 220; D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 82. Thus, we find it appropriate to use Unitil's electric and gas division's respective capital structures in calculating the return component of USC lease expenses.[114]

Accordingly, for Unitil's electric division's return component of USC facilities lease expense, the Department calculates the WACC using the electric division's ROE of 9.40 percent approved in this Order and the electric division's capital structure approved in this Order (see Section XI.D.5. below). Using the 9.40 percent ROE and the Company's approved capital structure produces an overall WACC of 7.46 percent (see Exh. DPU 50-16 & Atts. (electric)).[115] Similarly, for Unitil's gas division's return component of USC facilities lease expense, the Department calculates the WACC using the gas division's ROE of 9.40 percent approved in this Order and the gas division's capital structure approved in this Order (see Section XI.D.5. below). Use of the 9.40 percent ROE and the Company's approved capital structure produces an overall WACC of 7.46 percent (see Exh. DPU 39-3 & Atts. (gas)).

For the Liberty Lane building, the Company proposes a test-year expense of $184,868 for the electric division and $135,538 for the gas division (see Exhs. Unitil-WP 7.3 (Rev. 4)

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114 The Department will apply the electric and gas division's respective WACCs based on its respective capital structures and approved ROEs to UES and/or URC capital structures where applicable.

115 The Department notes that it has previously used the pre-tax WACC in the calculation of the return component of service company lease expense. D.P.U. 18-150, at 270-271; D.P.U. 17-05, at 220; D.P.U. 15-155, at 304; D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 82-83. In the instant proceedings, however, the Company's calculation of the return component of service company facilities lease expense separates the income tax and return calculations (Exhs. DPU 50-16, Atts. (electric); Unitil-CGDN-7, Att. 3, at 1-2 (Rev. 4) (gas); DPU 18-13, Att. 2, at 1 (Rev.) (gas); DPU 39-3, Atts. (gas)). As such, in this instance, the Department adjusts the return component of service company facilities lease expense using the WACC.

(electric); Unitil-WP 5.3 (Rev. 4) (gas)).[116] The USC allocated rent expense is composed of depreciation expense and a URC return component, which is based on URC's 2021 WACC of 7.07 percent (Exhs. DPU 50-16, Att. 1, at 1, 5 (electric); DPU 39-3, Att. 1, at 1, 5 (gas)). The appropriate return is the Company's electric division's approved WACC of 7.46 percent, and gas division's approved WACC of 7.46 percent, to calculate its allocation of test-year service company facilities lease expense. Application of this adjustment yields a rate-year USC lease expense of $1,250,164, allocated to the Company's electric and gas divisions based on their respective labor overhead allocators, and yields a lease expense for the Liberty Lane building of $189,275 for the electric division and $138,768 for the gas division (see Exhs. DPU 50-16, Att. 1, at 1, 5 (electric); Unitil-WP Allocators (Rev. 4) (electric); DPU 39-03, Att. 1, at 1, 5 (gas); Unitil-WP Allocators (Rev. 4) (gas)).[117, 118]

For the McGuire Street building, the Company proposes a test-year expense of $31,554 for the electric division and $23,134 for the gas division (see Exhs. Unitil-WP 7.3 (Rev. 4) (electric); Unitil-WP 5.3 (Rev. 4) (gas)).[119] The USC allocated rent expense is composed of depreciation expense and a URC return component, which is based on URC's 2021 WACC of 7.07 percent (Exhs. DPU 50-16, Att. 2, at 1, 8 (electric); DPU 39-3, Att. 2, at 1, 8 (gas)). In

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116 $1,221,060 x 15.14 percent = $184,868; $1,221,060 x 11.10 percent = $135,538

117 For the Liberty Lane building, the adjusted total USC rent expense of $1,250,164 is derived using Exhibits DPU 50-16, Att. 1, at 5 (electric) and DPU 39-3, Att. 1, at 5 (gas) and replacing the URC WACC of 7.07 percent on line 6 with the Company's approved WACC of 7.46 percent.

118 $1,250,164 x 15.14 percent = $189,275; $1,250,164 x 11.10 percent = $138,768

119 $208,416 x 15.14 percent = $31,554; $208,416 x 11.10 percent = $23,134

addition, URC's lease expense contains a UES return component, which is based on UES's 2021 WACC of 7.6 percent (Exhs. DPU 50-16, Att. 2, at 2, 7 (electric); DPU 39-3, Att. 2, at 2, 7 (gas)). The appropriate return is the Company's electric division's approved WACC of 7.46 percent, and gas division's approved WACC of 7.46 percent, to calculate its allocation of test-year service company facilities lease expense. Application of this adjustment yields a rate-year USC lease expense of $209,095 allocated to the Company's electric and gas divisions based on their respective labor overhead allocators, and yields a lease expense for the McGuire Street building of $31,657 for the Company's electric division and $23,210 for the Company's gas division (see Exhs. DPU 50-16, Att. 2, at 1-2, 7-8 (electric); Unitil-WP Allocators (Rev. 4) (electric); DPU 39-3, Att. 2, at 1-2, 7-8 (gas); Unitil-WP Allocators (Rev. 4) (gas)).[120, 121]

For the Energy Way building, the Company proposes a test-year expense of $61,281 for the electric division and $44,928 for the gas division (see Exhs. Unitil-WP 7.3 (Rev. 4) (electric); Unitil-WP 5.3 (Rev. 4) (gas)).[122] URC's rent expense is composed of depreciation expense and a UES return component, which is based on UES's 2021 WACC of 7.60 percent (Exhs. DPU 50-16, Att. 4, at 1, 6 (electric); DPU 39-3, Att. 4, at 1, 6 (gas)).[123] The appropriate

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120 For the McGuire Street building, the adjusted total USC rent expense of $209,095 is derived using Exhibits DPU 50-16, Att. 2, at 7-8 (electric) and DPU 39-3, Att. 2, at 7-8 (gas) and replacing the UES WACC of 7.60 percent at 7, line 6 and URC WACC of 7.07 percent at 8, line 6 with the company's approved WACC of 7.46 percent.

121 $209,095 x 15.14 percent = $31,657; $209,095 x 11.10 percent = $23,210

122 $404,760 x 15.14 percent = $61,281; $404,760 x 11.10 percent = $44,928

123 USC does not pay a return component for the Energy Way building (Exhs. DPU 50-16, Att. 4, at 2 (electric); DPU 39-3, Att. 4, at 2 (gas)).

return is the Company's electric division's approved WACC of 7.46 percent, and gas division's approved WACC of 7.46 percent, to calculate its allocation of test-year service company facilities lease expense. Application of this adjustment yields a rate-year USC lease expense of $400,196, allocated to the Company's electric and gas divisions based on their respective labor overhead allocators, and yields a lease expense for the Energy Way building of $60,590 for the Company's electric division and $44,422 for the Company's gas division (see Exhs. DPU 50-16, Att. 4, at 1, 6 (electric); Unitil-WP Allocators (Rev. 4) (electric); DPU 39-3, Att. 4, at 1, 6 (gas); Unitil-WP Allocators (Rev. 4) (gas)).[124,125]

For the Portsmouth building, the Company proposes a test-year expense of $32,074 for the electric division and $23,515 for the gas division (see Exhs. Unitil-WP 7.3 (Rev. 4) (electric); Unitil-WP 5.3 (Rev. 4) (gas)).[126] USC allocated rent expense is composed of depreciation expense and a Northern Utilities return component, which is based on Northern Utilities' 2021 WACC of 7.28 percent (Exhs. DPU 50-16, Att. 3, at 1, 6 (electric); DPU 39-3, Att. 3, at 1, 6 (gas)). The appropriate return is the Company's electric division's approved WACC of 7.46 percent, and the gas division's approved WACC of 7.46 percent, to calculate its allocation of test-year service company facilities lease expense. Application of the Company's approved WACC yields a rate-year USC lease expense of $213,565, allocated to the Company's electric

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124 For the Energy Way building, the adjusted total USC rent expense of $400,196 is derived using Exhibits DPU 50-16, Att. 4, at 6 (electric) and DPU 39-3, Att. 4, at 6 (gas) and replacing the UES WACC of 7.60 percent on line 6 with the Company's approved WACC of 7.46 percent.

125 $400,196 x 15.14 percent = $60,590; $400,196 x 11.10 percent = $44,422

126 $211,848 x 15.14 percent = $32,074; $211,848 x 11.10 percent = $23,515

and gas divisions based on their respective labor overhead allocators, and yields a lease expense for the Portsmouth building of $32,334 for the Company's electric division and $23,706 for the Company's gas division (see Exhs. DPU 50-16, Att. 3, at 1, 6 (electric); Unitil-WP Allocators (Rev. 4) (electric); DPU 39-3, Att. 3, at 1, 6 (gas); Unitil-WP Allocators (Rev. 4) (gas)).[127,128]

Finally, for the Training Facility, the Company proposes a test-year expense of $127,842 (Exhs. Unitil-CGDN-7, Att. 3, at 1 (Rev. 4) (gas); Sch. RevReq-3-18, line 5 (gas)). USC allocated rent expense is also composed of depreciation expense and a URC return component, which is based on URC's 2023 WACC of 7.14 percent (Exhs. Unitil-CGDN-7, Att. 3, at 1, 5 (Rev. 4) (gas)). URC allocated rent expense is composed of depreciation expense and a UES return component, which is based on UES's 2023 WACC of 7.51 percent (Exhs. Unitil-CGDN-7, Att. 3, at 2 (Rev. 4) (gas); DPU 18-13, Att. 2, at 5 (Rev.) (gas)). Application of the Company's approved WACC to the URC and UES capital structures yields a rate-year USC lease expense of $498,616 for the Training Facility, allocated to the Company's gas division based on its share of technicians who require operator qualification training, and yields a lease expense of $129,412 for the Company's gas division (see Exh. Unitil-CGDN-7, Att. 3, at 3 (Rev. 4) (gas); DPU 18-13, Att. 2, at 5 (Rev.) (gas)).[129]

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[127] $213,565 x 15.14 percent = $32,334; $213,565 x 11.10 percent = $23,706

[128] For the Portsmouth building, the adjusted total USC rent expense of $213,565 is derived using Exhibits DPU 50-16, Att. 3, at 6 (electric) and DPU 39-3, Att. 3, at 6 (gas) and replacing the Northern Utilities WACC of 7.28 percent on line 5 with the Company's approved WACC of 7.46 percent.

[129] For the Training Facility, the adjusted total USC rent expense of $498,616 is derived using Exhibits DPU 18-13, Att. 2, at 5 (Rev.) (gas) and Unitil-CGDN-7, Att. 3 (Rev. 4) (gas) and replacing the UES WACC of 7.51 percent on line 6 on Exhibit DPU 18-13,

The Department, therefore, approves a total increase of $4,078 for the Company's electric division, representing an increase of $4,406 related to the change in the WACC for the Liberty Lane building; an increase of $103 related to the change in the WACC for the McGuire Street building; a decrease of $691 related to the change in the WACC for the Energy Way building; and an increase of $260 related to the change in the WACC for the Portsmouth building (Exhs. DPU 50-16, Atts 1-4 (electric); Unitil-WP 7.3 (Rev. 4) (electric)).

For the Company's gas division, the Department approves a total increase of $4,560, representing an increase of $3,231 related to the change in the WACC for the Liberty Lane building; an increase of $75 related to the change in the WACC for the McGuire Street building; a decrease of $507 related to the change in the WACC for the Energy Way building; an increase of $191 related to the change in the WACC for the Portsmouth building, and an increase of $1,570 related to the change in the WACC for the Training Facility (Exhs. Unitil-CGDN-7, Att. 3 (Rev. 4) (gas); Unitil-WP 5.3 (Rev. 4) (gas); DPU 18-13, Att. 2 (Rev.) (gas); DPU 39-3, Atts. (gas)).

Based on the above adjustments, the Department increases the Company's electric division's proposed service company facilities lease expense by $4,078 for a total of

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Att. 2, at 5 (Rev.) (gas) and URC WACC of 7.14 percent on line 6 of Exhibit Unitil-CGDN-7, Att. 3, at 5 (Rev. 4) (gas) with the Company's approved WACC of 7.46 percent.

$313,855,[130] and the Company's gas division's proposed service company facilities lease expense by $4,560, for a total of $359,517.[131]

L. Rate Case Expense

1. Introduction

Initially, the Company estimated that it would incur $832,000 in rate case expense for its electric division and $678,000 for its gas division for a total rate case expense of $1,510,000 (Exhs. Unitil-CGDN-1, at 37 (electric); Sch. RevReq-3-10 (electric); Unitil-CGDN-1, at 33 (gas); Sch. RevReq-3-13 (gas)). Based on its final invoices and projected costs to complete the compliance filing, the Company proposes a final rate case expense for its electric division of $1,014,625 and a rate case expense of $993,240 for its gas division, for a total rate case expense of $2,007,865 (Exhs. Sch. RevReq-3-10 (Rev. 4) (electric); DPU 17-8, Att. C (Supp. 2) (electric); Sch. RevReq-3-13 (Rev. 4) (gas); DPU 16-8, Att. C (Supp. 2)). The Company's proposed rate case expense includes costs related to legal representation, rate case support, and expert consulting services related to the Company's (1) PBR proposal, (2) depreciation study, (3) allocated cost of service study ("ACOSS") and marginal cost of service study, and (4) ROE proposal (Exhs. Unitil-CGDN-1, at 34-35 (electric); Unitil-CGDN-1, at 32-33 (gas)).

For both the electric division and gas division, the Company proposes to normalize the rate case expense over a five-year period based on its proposed PBR term (Exhs. Unitil-CGDN-1, at 38 (electric); Unitil-CGDN-1, at 35-36 (gas)). Normalizing the

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130 $309,777 + $4,078 = $313,855

131 $227,115 + $127,842 + $4,560 = $359,517

Company's proposed rate case expense for the electric division of $1,014,625 over five years produces an annual expense of $202,925 (Exh. Sch. RevReq-3-10 (Rev. 4) (electric)). Normalizing the Company's proposed rate case expense for the gas division of $993,240 over five years produces an annual expense of $198,648 (Exh. Sch. RevReq-3-13 (Rev. 4) (gas)).

2. Positions of the Parties

Unitil maintains that it has demonstrated that its competitive solicitation process to retain outside consultants was carefully developed and implemented to help ensure retention of qualified individuals and firms while controlling costs (Company Brief at 225 (electric); Company Brief at 192 (gas)). The Company acknowledges that it did not use a competitive solicitation process for one of its rate case consultants, but asserts that it was appropriate to forego a competitive solicitation process in this instance because the consultant is a former employee who possesses a unique skill set (Company Brief at 225 (electric); Company Brief at 193 (gas)).

The Company contends that it developed an electronic tracking method to ensure the adequacy of the invoices and supporting documentation (Company Brief at 225-226 (electric); Company Brief at 193 (gas)). In addition, Unitil maintains that it has taken steps to control rate case costs, including working closely with its outside consultants to be as efficient and cost-effective as possible by providing thorough responses to consultant inquiries, preparing workpapers for the consultants' use in developing testimony, and assisting the consultants with information requests propounded in the case (Company Brief at 226 (electric), citing Exh. DPU 17-18 (electric); Company Brief at 193 (gas), citing Exh. DPU 16-18 (gas)). No intervenor commented on the Company's rate case expense on brief.

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that actually has been incurred and, thus, is considered known and measurable. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 226-227; D.P.U. 95-118, at 115-119.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; D.T.E. 02-24/25, at 192; D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate case expenses looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers. D.P.U. 10-114, at 220; D.P.U. 09-39, at 289-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 152-154. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 220; D.P.U. 10-55, at 323; see also D.P.U. 93-223-B at 16-17.

b. Competitive Bidding Process

i. Introduction

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. See, e.g., D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.T.E. 05-27, at 158-59; D.T.E. 03-40, at 148; D.T.E. 02-24/25, at 192. If a petitioner elects to secure outside services for rate case expense, it must engage in a competitive bidding process for these services. D.P.U. 10-114, at 221; D.P.U. 09-30, at 227; D.P.U. 07-71, at 99-100, 101; D.T.E. 03-40, at 153. In all but the most unusual of circumstances, it is reasonable to expect that a company can comply with a competitive bidding requirement. D.P.U. 10-55, at 342. The Department fully expects that competitive bidding for outside rate case services, including legal services, will be the norm. D.P.U. 10-55, at 342.

The requirement of having to submit a competitive bid in a structured and organized process serves several important purposes. First, the competitive bidding and qualification process provides an essential, objective benchmark for the reasonableness of the cost of the services sought. D.P.U. 10-114, at 221; D.P.U. 09-30, at 228-229; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Second, it keeps even a consultant with a stellar past performance from taking the relationship with a company for granted. D.P.U. 10-114, at 221; D.P.U. 07-71, at 101; D.T.E. 03-40, at 152. Finally, a competitive solicitation process serves as a means of cost containment for a company. D.T.E. 03-40, at 152-153.

The competitive bidding process must be structured and objective and be based on a request for proposal ("RFP") process that is fair, open, and transparent. D.P.U. 10-114, at 221, 224; D.P.U. 09-30, at 227-228; D.P.U. 07-71, at 99-100; D.T.E. 03-40, at 153. The timing of the RFP process should be appropriate to allow for a suitable field of potential service providers to provide complete bids and provide the company with sufficient time to evaluate the bids. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFP issued to solicit service providers must clearly identify the scope of work to be performed and the criteria for evaluation. D.P.U. 10-114, at 221-222; D.P.U. 10-55, at 343.

The Department does not seek to substitute its judgment for that of a petitioner in determining which service provider may be best suited to serve the petitioner's interests and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The need to contain rate case expense, however, should be accorded a high priority in the review of bids received for case work. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. In seeking recovery of rate case expense, companies must provide an adequate justification and showing, with contemporaneous documentation, that their choice of outside services is both reasonable and cost-effective. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153.

ii. Company's RFP Process

The Company's proposed rate case expense includes costs related to legal representation, rate case support, and expert consulting services related to the Company's (1) PBR proposal, (2) depreciation study, (3) ACOSS and marginal cost of service study; and (4) ROE proposal (Exhs. Unitil-CGDN-1, at 34-35 (electric); Unitil-CGDN-1, at 32-33 (gas)). The Company demonstrated that it conducted a competitive bidding process for each of its service providers, with the exception of a retired, long-time employee who provided regulatory support on a consultant basis (Exhs. DPU 17-1 & Atts. (electric); DPU 17-2 & Atts. (electric); DPU 17-3 (electric); DPU 17-7 (electric); DPU 16-1 & Atts. (gas); DPU 16-2 & Atts. (gas); DPU 16-3 (gas); DPU 16-7 (gas)).

The Department has determined that if a company decides to forgo the competitive bidding process, there must be an adequate justification for the company's decision to do so. D.P.U. 14-150, at 219; D.T.E. 01-56, at 76. In this instance, the retired, long-time employee had direct experience and expertise in providing regulatory support for base distribution rate case proceedings (Exhs. DPU 17-7 (electric); DPU 16-7 (gas)). The costs expended for this former employee were less than $5,000 combined across electric and gas issues (Exhs. DPU 17-8 (Supp. 2), Att. c (electric); DPU 16-8 (Supp. 2), Att. c (gas)). We conclude that it is unlikely that an alternative service provider, less familiar with the Company, could duplicate these regulatory support services for a lower cost, especially when considering the expense associated with issuing an RFP for such services. D.P.U. 20-120, at 337; D.P.U. 13-75, at 237; D.P.U. 12-25, at 192; D.P.U. 09-30, at 233. The Department finds that, in this limited circumstance, conducting a separate RFP for the sake of process, rather than to establish a field of potential bidders and establish price and non-price qualifications, would have been inefficient. See, e.g., D.P.U. 13-75, at 237; D.P.U. 12-25, at 192; D.P.U. 09-30, at 232. Thus, we find that there is sufficient justification for the Company to forego the competitive bidding process in selecting the retired, long-time employee, and we find that the Company's selection of this contractor was reasonable.

With respect to the remaining service providers who were selected via an RFP process, we conclude that the Company's choices regarding its consultants, including attorneys, were reasonable and cost effective (Exhs. DPU 17-1 & Atts. (electric); DPU 17-2 & Atts. (electric); DPU 17-3 (electric); DPU 16-1 & Atts. (gas); DPU 16-2 & Atts. (gas); DPU 16-3 (gas)). We also find that the Company appropriately considered price and non-price factors before selecting the providers that it determined would provide the best combination of price and appropriate quality of service (Exhs. DPU 17-2 & Atts. (electric); DPU 17-3 (gas); DPU 16-2 & Atts. (gas); DPU 16-3 (gas)). For each category, the Company appropriately selected a provider that possessed expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks for which it was requested to bid (Exhs. DPU 17-2, Atts. b01 through b06 (electric); DPU 16-2, Atts. b01 through b06 (gas)). Based on the foregoing, the Department concludes that the Company conducted a fair, open, and transparent competitive bidding process for the attorneys and consultants (Exhs. DPU 17-1 (electric), DPU 17-2 (electric); DPU 16-1 (gas), DPU 16-2 (gas)).

c. Various Rate Case Expenses

The Department has directed companies to provide all invoices for outside rate case services that detail the number of hours billed, the billing rate, and the specific nature of the services performed. D.P.U. 10-114, at 235-236; D.T.E. 03-40, at 157; D.T.E. 02-24/25, at 193-194. The Department has reviewed the invoices provided by the Company and finds that the invoices are properly itemized (see, e.g., Exhs. DPU 17-8 & Atts. (electric); DPU 17-8 & Atts. (Supp. 1) (electric); DPU 17-8 & Atts. (Supp. 2) (electric); DPU 16-8 & Atts. (gas); DPU 16-8 & Atts. (Supp. 1) (gas); DPU 16-8 & Atts. (Supp. 2) (gas)). Further, the final rate case expense includes fixed fees for work on the reply brief, review of the Department's final order, and preparation of the compliance filing (Exhs. DPU 17-8 & Atts. (Supp. 2) (electric); DPU 16-8 & Atts. (Supp. 2) (gas)).

While the costs for some providers increased from those initially proposed, a review of the invoices demonstrates that the extra costs were for work performed during the discovery period and hearing phase (see, e.g., Exhs. DPU 17-1, Atts. D1, D10, D11 (electric); DPU 17-8, Atts. A2, A3, A4 (electric); DPU 16-1, Atts. F1, F3, F4, F5 (gas); DPU 16-8, Atts. A2, A3, A5 (gas); DPU 16-8, Att. A4 (Supp. 1) (gas)). In this proceeding, the Company responded to 1,701 information requests propounded by the Attorney General, DOER, and the Department comprising 954 information requests for the Company's electric division and 745 information requests for the gas division. The Department also held twelve days of evidentiary hearings and the Company responded to 81 record requests issued at those hearings. In contrast, the entire evidentiary record in the Company's previous litigated rate case consisted of approximately 1,475 exhibits and approximately 100 responses to record requests, along with eight days of evidentiary hearings. D.P.U. 15-80/D.P.U. 15-81, at 3, 5. Given the number of information requests propounded as well as the length of the evidentiary hearings, we find it reasonable that the costs increased from those originally estimated. Based on our review of the record evidence, the Department finds that the total costs associated with each service provider are reasonable, appropriate, and proportionate to the overall scope of work provided and were prudently incurred (see, e.g., Exhs. DPU 17-8, Atts. (electric); DPU 17-8, Atts. (Supp. 1) (electric); DPU 17-8, Atts. (Supp. 2) (electric); DPU 16-8, Atts. (gas); DPU 16-8, Atts. (Supp. 1) (gas); DPU 16-8, Atts. (Supp. 2) (gas)).

Unitil also seeks to include miscellaneous costs of $5,296 and $3,523 for the electric division and gas division, respectively (Exhs. DPU 17-8, Att. C (Supp. 2) (electric); DPU 16-8, Att. C (Supp. 2) (gas)). These miscellaneous costs include expenses associated with emailing services, translation services, and auditorium rental and police detail for the public hearing (Exhs. DPU 17-8, Att. C (Supp. 2) (electric); DPU 16-8, Att. C (Supp. 2) (gas)). The Department has reviewed the invoices provided by the Company for these miscellaneous costs and finds that such invoices are properly itemized (Exhs. DPU 17-8, Att. A7 (electric); DPU 17-8, Att. A7 (Supp. 1) (electric); DPU 16-8, Att. A7 (gas); DPU 16-8, Att. A7 (Supp. 1) (gas)). In addition, the Department finds that these miscellaneous costs are reasonable and appropriate and were prudently incurred (Exhs. DPU 17-8, Att. A7 (electric); DPU 17-8, Att. A7 (Supp. 1) (electric); DPU 16-8, Att. A7 (gas); DPU 16-8, Att. A7 (Supp. 1) (gas)).

d. Normalization of Rate Case Expense

The proper method to calculate a rate case expense adjustment is to determine the rate case expense, normalize the expense over an appropriate period, and then compare it to the test-year level to determine the adjustment. D.P.U. 10-55, at 338-339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 197; D.T.E. 98-51, at 62; D.P.U. 95-40, at 58. The Department's practice is to normalize rate case expense so that a representative annual amount is included in the cost of service. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163; D.T.E. 03-40, at 163; D.T.E. 02-24/25, at 191; D.T.E. 01-56, at 77; D.T.E. 98-51, at 53; D.P.U. 96-50 (Phase I) at 77. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense; rather, it is intended to include a representative annual level of expense. D.P.U. 10-55, at 339;

D.T.E. 05-27, at 163; D.T.E. 03-40, at 163-164; D.T.E. 02-24/25, at 191; D.P.U. 96-50 (Phase I) at 77.

Typically, the Department determines the appropriate period for recovery of rate case expense by taking the average of the intervals between the filing dates of a company's last four base distribution rate cases, including the present case, rounded to the nearest whole number. D.P.U. 10-55, at 339; D.T.E. 05-27, at 163 n.105; D.T.E. 03-40, at 164 n.77; D.T.E. 02-24/25, at 191. If the resulting normalization period is deemed unreasonable or if the company has an inadequate rate case filing history, the Department will determine the appropriate normalization period based on the particular facts of the case. South Egremont Water Company, D.P.U. 86-149, at 2-3 (1986).

For the electric division, the average interval between the filing dates of the Company's last rate cases is three years (Exhs. Unitil-CGDN-1, at 38 (electric); Sch. RevReq-3-10 (electric)).[132] For the gas division, the average interval between the filing dates of the Company's last four rate cases is four years (Exhs. Unitil-CGDN-1, at 35-36 (gas); Sch. RevReq-3-13 (gas)).[133] Based on its proposed PBR term, the Company proposes a five-year normalization period (Exhs. Sch. RevReq-3-10 (Rev. 3) (electric); Sch. RevReq-3-10 (Rev. 3) (gas)). As outlined in Section III.D.5. above, the Department has approved a PBR plan for the Company that includes a five-year term and stay-out provision. The Department has

[132] In addition to the current filing, the Company's prior rate case filings for the electric division were D.P.U. 19-130, D.P.U. 15-80, and D.P.U. 13-90 (Exh. Sch. RevReq-3-10 (electric)).

[133] In addition to the current filing, the Company's prior rate case filings for the gas division were D.P.U. 19-131, D.P.U. 15-81, and D.P.U. 11-02 (Exh. Sch. RevReq-3-13 (gas)).

previously considered the term of a PBR in establishing an appropriate rate case expense normalization period. D.P.U. 22-22, at 249-250; D.P.U. 17-05, at 282-282; D.P.U. 09-30, at 241. The Department has found that the term of a PBR that prevents a company from filing a new base distribution rate case for a predetermined period provides a more representative basis for establishing a rate case expense normalization period. D.P.U. 22-22, at 250; D.P.U. 17-05, at 282; D.P.U. 96-50 (Phase I) at 78. Accordingly, the Department finds that the Company's proposed normalization period of five years for both the electric division and gas division is appropriate.

e. Conclusion

The Company proposed and the Department has accepted a final rate case expense for its electric division of $1,014,625 and a rate case expense of $993,240 for its gas division, for a total rate case expense of $2,007,865 (Exhs. Sch. RevReq-3-10 (Rev. 4) (electric); Sch. RevReq-3-13 (Rev. 4) (gas)). The annual level of normalized rate case expense for the electric division is $202,925 ($1,014,625 divided by five years). During the test year, the Company booked $302,702 in rate case expense for the electric division (Exh. Sch. RevReq-3-10 (Rev. 4) (electric)). The Company proposes to decrease this amount by $99,777 to incorporate this annual level of normalized rate case expense for ratemaking purposes (Exh. Sch. RevReq-3-10 (Rev. 4) (electric)). The annual level of normalized rate case expense for the gas division is $198,648 ($993,240 divided by five years). During the test year, the Company booked $28,100 in rate case expense for the gas division (Exh. Sch. RevReq-3-13 (Rev. 4) (gas)). The Company proposes to increase this amount by $170,549 to incorporate this annual level of normalized rate case expense for rulemaking purposes (Exh. Sch. RevReq-3-13 (Rev. 4) (gas)). Based on the findings above, the Department accepts the Company's proposed adjustments.

M. Inflation Allowance

1. Introduction

Unitil proposes an inflation allowance of $258,876 for its electric division and $149,128 for its gas division (Exhs. Sch. RevReq-3-17, at 1 (Rev. 4) (electric); Sch. RevReq-3-19, at 1 (Rev. 4) (gas)).[134] To arrive at the proposed inflation allowance for the electric division, Unitil took the electric division's adjusted test-year O&M expense of $14,188,363, and subtracted $8,100,695, which represents test-year expenses associated with the various O&M expense categories for which Unitil seeks separate adjustments (Exh. Sch. RevReq-3-17, at 1 (Rev. 4)

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134 In its initial filing, Unitil proposed an inflation allowance of $349,322 for its electric division and $161,620 for its gas division (Exhs. Unitil-CGDN-1, at 54 (electric); Unitil-CGDN-1, at 43 (gas); Sch. RevReq-3-17 (electric); Sch. RevReq-3-19 (gas)). During the proceedings, these amounts were adjusted to correspond to adjustments made to expenses.

(electric)).[135,136] Next, Unitil excluded various O&M expense categories that are not subject to inflation, totaling $1,565,117 (Exh. Sch. RevReq-3-17, at 1 (Rev. 4) (electric)).[137] Finally, Unitil calculated a proposed inflation factor of 7.18 percent using the most recent forecast of the gross domestic product implicit price deflator ("GDPIPD") (as sourced from the Energy Information Administration) from the midpoint of the test year to the midpoint of the rate year (Exhs. Sch. RevReq-3-17, at 2 (Rev. 4) (electric); Unitil-WP 7.1 (Rev. 4) (electric)).[138] Unitil multiplied the 7.18 percent inflation factor by the electric division's adjusted test-year residual O&M expenses of $4,522,551 to arrive at a proposed inflation allowance of $324,719 for the

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135 Unitil seeks separate adjustments of, or removes from the inflation allowance, the following electric division expense categories: (1) sale for resale; (2) payroll expense; (3) medical/dental/vision insurance; (4) 401(k) costs; (5) deferred compensation; (6) property and liability insurance; (7) normalized rate case expense; (8) EV program consulting reclassification; (9) grid modernization program customer engagement cost reclassification; (10) Section 83 A/C/D cost reclassification; (11) pandemic costs; (12) normalization self-insurance expense; (13) postage expense; (14) EEI lobbying expenses; (15) certain USC membership and dues; (16) VMP USC labor adjustment; (17) SRP expense; (18) out of period VMP adjustment (19) shareholder expenses; (20) regulatory assessments; and (21) test-year storm deductibles (Exh. Sch. RevReq-3-17, at 1 (Rev. 4) (electric)).

136 The Department notes that the amount the Company removed for the VMP USC labor adjustment of $207,274 is incorrect and that the correct amount is $201,274 (Exhs. Unitil-RevReq-Rebuttal at 20 (electric); DPU 11-08, Att. 1 (electric)).

137 Unitil excluded from the electric division inflation allowance calculation the following expense categories: (1) pension; (2) PBOP; (3) supplemental executive retirement plan; (4) bad debts; (5) USC amortizations; and (6) USC facility leases (Exh. Sch. RevReq-3-17, at 1 (Rev. 4) (electric)).

138 In its initial filing, Unitil calculated a proposed inflation factor of 7.21 percent using the change in GDPIPD from the midpoint of the test year to the midpoint of the rate year (Exhs. Unitil-CGDN-1, at 54 (electric); Unitil CGDN-1, at 43 (gas); Sch. RevReq-3-17 (electric); Sch. RevReq-3-19 (gas)). As noted, the Company updated the factor based on a most recent forecast of GDPIPD.

electric division (Exh. Sch. RevReq-3-17, at 1 (Rev. 4) (electric)). Of this amount, the Company assigned $65,843 to internal transmission and $258,876 to base distribution (Exhs. Sch. RevReq-3-17, at 1 (Rev. 4) (electric); Unitil-WP 1.2 (Rev. 4) (electric); Unitil-WP 1.3 (Rev. 4) (electric)).[139]

Similarly, to arrive at the proposed inflation allowance for the gas division, the Company took the adjusted test-year O&M expense of $8,325,007, and subtracted $5,128,385, which represents test-year O&M expenses associated with the various categories for which Unitil seeks separate adjustments (Exh. Sch. RevReq-3-19, at 1 (Rev. 4) (gas)).[140] Next, Unitil excluded various O&M expense categories for its gas division that are not subject to inflation, totaling $1,119,626.[141] The Company then calculated the same 7.18 percent inflation factor as used for

139 The Department notes that in calculating the amount assigned to internal transmission, the Company used an inflation rate of 7.22 percent, rather than the final updated figure of 7.18 percent as provided in Exhibit Sch. RevReq-3-17, at 2 (Rev. 4) (electric) (Exhs. Unitil-WP 1.2 n.2 (Rev. 4) (electric); Unitil-WP 1.3 n.2 (Rev. 4) (electric)). The Department will use the correct amount assigned to internal transmission, based on the 7.18 percent inflation rate in Schedule 2A, below.

140 Unitil seeks separate adjustments of, or removes from the inflation allowance, the following gas division expense categories: (1) payroll expense; (2) medical/dental/vision insurance; (3) 401(k) costs; (4) deferred compensation; (5) property and liability insurance; (6) normalized rate case expense; (7) normalized self-insurance expense; (8) postage expense; (9) pandemic costs; (10) AGA lobbying costs; (11) CRNG lobbying costs and duplicated invoice; (12) certain USC membership and dues; (13) gas marketing expenses; (14) shareholder expenses; (15) regulatory assessments; and (16) Asset Management Agreement margin-sharing revenue (Exh. Sch. RevReq-3-19 (Rev. 4) (gas)).

141 Unitil excluded from the inflation allowance calculation the following gas division expense categories: (1) pension; (2) PBOP; (3) supplemental executive retirement plan; (4) bad debts; (5) USC amortizations; and (6) USC facility leases (Exh. Sch. RevReq-3-19, at 1 (Rev. 4) (gas)).

the electric division and multiplied it by the adjusted test-year residual O&M expenses of $2,076,997 to arrive at a proposed inflation allowance of $149,128 for its gas division (Exhs. Sch. RevReq-3-19, at 1, 2 (Rev. 4) (gas); Unitil-WP 5.1 (Rev. 4) (gas)).

2. Positions of the Parties

The Company asserts that it calculated the inflation allowance to recognize the impact of inflation on its expenses (Company Brief at 242 (electric), citing Exh. Unitil-CGDN-1, at 53 (electric); Company Brief at 208 (gas), citing Exh. Unitil-CGDN-1, at 42 (gas)). The Company maintains that it has reduced test-year O&M expenses by expenses that have been separately adjusted by the Company and that are not subject to general inflation (Company Brief at 243 (electric), citing Exhs. Unitil-CGDN-1, at 54 (electric); Sch. RevReq-3-17, at 1 (Rev. 4) (electric); Company Brief at 208 (gas), citing Exhs. Unitil-CGDN-1, at 43 (gas); Sch. RevReq-3-19 (Rev. 4) (gas)). Further, the Company states that it has calculated the inflation factor projected to January 1, 2025 (Company Brief at 243-244 (electric), citing Exhs. Unitil-CGDN-1, at 54 (electric); Sch. RevReq-3-17, at 2 (Rev. 4) (electric); DPU 29-4 (electric); Company Brief at 208 (gas), citing Exhs. Unitil-CGDN-1, at 43 (gas); Sch. RevReq-3-19, at 2 (Rev. 4) (gas); DPU 20-9 (gas)).

In addition, Unitil maintains that it has provided evidence of cost-saving measures associated with its residual O&M accounts and that it is continuously looking for opportunities for cost savings that result in lower rates for customers, such as minimizing budget variances and bidding and monitoring pricing for outside services (Company Brief at 244 (electric), citing Exh. DPU 8-19 (electric); Company Brief at 209 (gas), citing Exh. DPU 8-1 (gas)). Further, the Company states that it undergoes a comprehensive budget review on an annual basis and considers every line item, every departmental budget category, and every area of expense when budgeting for the coming year (Company Brief at 244 (electric), citing Exhs. Unitil-JFC-1, at 15; DPU 8-19 (electric); Company Brief at 209 (gas), citing Exhs. Unitil-JFC-1, at 15; DPU 8-1 (gas)). No other party addressed the Company's proposed inflation allowance on brief.

3. Analysis and Findings

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I) at 112-113; D.P.U. 95-40, at 64. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogeneous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. Boston Edison Company, D.P.U. 1720, at 19-21 (1984); Commonwealth Electric Company, D.P.U. 956, at 40 (1982). The Department permits utilities to increase their test-year residual O&M expense by an independently published price index from the midpoint of the test year to the midpoint of the rate year. D.P.U. 19-120, at 316; D.P.U. 17-170, at 147; D.P.U. 17-05, at 329. For the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. D.P.U. 19-120, at 316; D.P.U. 17-170, at 147; D.P.U. 17-05, at 329.

In the instant case, we are satisfied that Unitil has demonstrated a number of cost containment measures associated with the Company's residual O&M accounts. These efforts include continuously seeking cost savings; periodic reviews of operating costs to minimize budget variances; the use of competitive solicitation processes for outside vendors such as construction contracting and insurance; and comprehensive annual budget reviews

(Exhs. Unitil-JFC-1, at 15; DPU 8-19 (electric); DPU 8-1 (gas)). Based on these considerations, the Department finds that Unitil demonstrated that it has implemented cost containment measures sufficient to qualify it for an inflation allowance.

Unitil calculated its proposed inflation factor from the midpoint of the test year to the midpoint of the rate year, using the most recent GDPIPD as an inflation measure (Exhs. Sch. RevReq-3-17, at 2 (Rev. 4) (electric); Unitil-WP 7.1 (Rev. 4) (electric) Sch. RevReq-3-19, at 2 (Rev. 4) (gas); Unitil-WP 5.1 (Rev. 4) (gas)). This calculation method and use of GDPIPD are consistent with Department precedent. D.P.U. 19-120, at 316-317; D.P.U. 17-170, at 147; D.P.U. 17-05, at 330. Therefore, the Department concludes that Unitil has properly calculated an inflation factor of 7.18 percent (Exhs. Sch. RevReq-3-17, at 2 (Rev. 4) (electric); Sch. RevReq-3-19, at 2 (Rev. 4) (gas); Unitil-WP 7.1 (Rev. 4) (electric); Unitil-WP 5.1 (Rev. 4) (gas)).

If an O&M expense has been adjusted or disallowed for ratemaking purposes such that the adjusted expense is representative of costs to be incurred in the year following new rates, the expense is also removed in its entirety from the inflation allowance. D.P.U. 09-39, at 322; D.T.E. 05-27, at 204; D.T.E. 02-24/25, at 184-185; Blackstone Gas Company, D.T.E. 01-50, at 19 (2001); D.P.U. 88-67 (Phase I) at 141; Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987). To calculate the inflation allowance, Unitil reduced its test-year O&M for 27 electric division expense categories and 22 gas division expense categories (Exhs. Sch. RevReq-3-17, at 1 (Rev. 4) (electric); Sch. RevReq-3-19, at 1 (Rev. 4) (gas)). The Department accepts these adjustments subject to our findings below.

In Section VI.F.2. above, the Department denied the Company's expenses related to certain non-industry dues for both the electric and gas divisions and AGA and CRNG membership dues for the Company's gas division. The Department also removes the gas division test-year amount of $205,365 related to Account 887 maintenance of mains, as it is normalized and thus separately adjusted (Exh. Sch. RevReq-3-16 (Rev. 4) (gas)).

In addition, in Section VIII.C.4. below, the Department accepts the Company's test-year expenses related to the SRP. As noted below, the Company initially proposed an SRP reconciling mechanism and a corresponding adjustment to remove SRP expenses from the residual O&M expense. Based on our decision, the Department increases the residual O&M expense by the allowed SRP test-year expense, excluding SRP-related labor costs that are separately adjusted (Exhs. Sch. RevReq-3-11, line 8 (Rev. 4) (electric); DPU 30-5, Att. 1, at 5 (electric); Tr. 2, at 132). The effects of the Department's adjustments are shown below in Schedule 2A for the electric division and Schedule 2B for the gas division.

Based on the above, the Department finds that an inflation allowance equal to the most recent forecast of GDPIPD for the period proposed by the Company, applied to Unitil's electric and gas divisions approved levels of residual O&M expense, is appropriate. As shown in Schedule 2A below, the Department approves an inflation allowance for electric division of $296,917 (see Exh. Sch. RevReq-3-17 (Rev. 4) (electric)). As shown in Schedule 2B below, the Department approves an inflation allowance for the gas division of $130,946 (see Exh. Sch. RevReq-3-19 (Rev. 4) (gas)).

VII. PENSION AND POST-RETIREMENT BENEFITS OTHER THAN PENSION

A. Background

In December 1985, the Financial Accounting Standards Board ("FASB") issued FAS 87 effective January 1, 1987, which established new accounting standards that significantly changed the manner in which companies account for their obligations relating to employee pensions.[142] In December 1990, the FASB issued FAS 106 effective January 1, 1993, which established similar accounting standards relating to PBOP.[143] Through the issuance of FAS 87 and FAS 106, FASB established a systematic method for all companies to recognize employees' future retirement benefit costs as they accrue over each employee's service life.[144] Although FASB dictates the accounting treatment for pension and PBOP expenses, actual contributions to the pension and PBOP plans are made pursuant to the requirements of the federal Employee Retirement Income Security Act of 1974.

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[142] FAS 87 provides the standard of reporting in financial statements of pension plan assets, obligations, and the net periodic costs resulting from annual actuarial remeasurement of the pension plans. FAS 87 also provides that reporting in financial statements is on an accrual basis recognizing related events gradually in subsequent periods.

[143] Similar to FAS 87, FAS 106 provides the standard of reporting in financial statements of the PBOP plan assets, obligations, and net periodic costs resulting from annual actuarial remeasurement of the PBOP plans. FAS 106 also provides that the reporting in financial statements is on an accrual basis recognizing related events gradually in subsequent periods.

[144] In 2009, as part of a general recodification of its accounting rulings, FASB consolidated FAS 87 with FAS 106 into FASB Accounting Standards Codification 715. The evidentiary record references FAS 87, FAS 106, and Accounting Standards Codification 715, and Unitil's tariffs retain their historical references to FAS 87 and FAS 106. This Order will rely on the references to FAS 87 and FAS 106.

Prior to these new rules, the Department's accounting treatment for pension expense varied by company. See, e.g., D.P.U. 85-270, at 187-188 (pension expense based on most recent actuarial report); Haverhill Gas Company, D.P.U. 155, at 20-22 (1980) (pension expense based on contribution to a company-sponsored trust). The Department allowed most companies to account for their PBOP obligations on a "pay as you go" basis. This approach allowed the companies to charge PBOP costs to expense only when benefits were, in fact, paid out to or for the benefit of retirees. See D.P.U. 92-78, at 83; Bay State Gas Company, D.P.U. 89-81, at 29 (1989). Thus, the service benefits enjoyed by one generation of ratepayers from the work performed to serve them by a contemporary generation of utility workers were, in no small part, to be paid for by a future generation of ratepayers, who would bear the costs (on a pay as you go basis) of pension obligations accrued to fund the retirement trust of that earlier generation of utility workers. NSTAR Pension, D.T.E. 03-47-A at 4 (2003).

Over the years, changes in accounting rules required the Department to reexamine how best to include a representative level of pension and PBOP expenses in base rates. See D.P.U. 89-81, at 29-35; D.P.U. 87-260, at 39-47. Initially, the Department did not endorse any specific ratemaking method and treated these expenses on a case-by-case basis. See D.P.U. 96-50 (Phase I) at 81. For pension expenses, typically the Department used an amount equal to the cash contribution to the pension plan as the representative level of pension expense to include in base distribution rates because the Department did not view pension expense recorded for accounting purposes as a true measure of the annual cost of providing employee retirement benefits. See, e.g., D.P.U. 89-114/90-331/91-80 (Phase One) at 65-66; Western Massachusetts Electric Company, D.P.U. 88-250, at 67-72 (1989); D.P.U. 87-260, at 44-47.

Regarding PBOP expense, the Department balanced the competing interests of (1) FAS 106 and (2) the need to allocate PBOP expenses appropriately and in a cost-effective manner between current and former ratepayers, as well as between ratepayers and shareholders. See, e.g., D.P.U. 96-50 (Phase I) at 81; D.P.U. 92-250, at 54.

In late 2002, Boston Edison Company, Commonwealth Electric Company, Cambridge Electric Light Company, and NSTAR Gas Company (collectively, the "NSTAR companies") petitioned the Department for assistance in addressing the differences between federally mandated pension and PBOP contributions and the resulting under-recovery of these costs through base distribution rates. Boston Edison Company et al., D.T.E. 02-78 (2002). The Department approved the NSTAR companies' proposal to establish (1) a regulatory asset to recover certain past pension and PBOP costs; and (2) on an ongoing basis, a deferral to recover the difference between the amount of pension and PBOP expenses recorded under the accounting rules and the amount collected in base rates. D.T.E. 02-78, Stamp Approval (December 20, 2002); see also D.T.E. 03-47-A at 7. The Department's approval also authorized the NSTAR companies to petition the Department to propose a reconciling mechanism to provide for the reconciliation between the amount of pension and PBOP expense recovered through base distribution rates and the FAS 87 and FAS 106 expenses recovered on the NSTAR companies' books over a specific period. D.T.E. 02-78, Stamp Approval at 2-3 (December 20, 2002).

Subsequently, in D.T.E. 03-47, the Department addressed the NSTAR companies' request for a reconciling mechanism. The Department found that between 1999 and 2003, the effects of a declining stock market and steeply falling interest rates had taken their toll on the valuation of the NSTAR companies' pension and PBOP plans, and that without relief the

NSTAR companies would be subject to a FAS-required equity write-down entailing significant and impairing financial consequences, with adverse effects on customers. D.T.E. 03-47-A at 19-26, 28. The Department also found a high degree of volatility in the NSTAR companies' pension and PBOP expenses between 1996 and 2003. D.T.E. 03-47-A at 26. The Department determined that approving a reconciling mechanism for pension and PBOP obligations would be equitable because customers would pay no more than the actual costs incident to (and demanded by FASB to support) pensions and PBOP for the utility workers who provide daily service to customers year-in, year-out until retirement. D.T.E. 03-47-A at 27. Thus, the Department approved the NSTAR companies' requested reconciling mechanism, with certain modifications. D.T.E. 03-47-A at 29-46.

B. Company PAM

In April 2004 Unitil petitioned the Department for approval to establish an annual adjustment factor to recover costs associated with the Company's pension and PBOP obligations that were not currently being collected in base distribution rates. Fitchburg Gas and Electric Light Company, D.T.E. 04-48, at 1 (2004). Specifically, the Company's proposal provided for the recovery of regulatory deferrals previously approved by the Department in Fitchburg Gas and Electric Light Company, D.T.E. 03-131 (2004).[145] D.T.E. 04-48, at 1-2. The Department found that the Company's proposal was consistent with the reconciling mechanism approved for the NSTAR companies and that without such a reconciling mechanism, Unitil would be subject to a

145 The regulatory deferrals approved in D.T.E. 03-131 also included amounts previously approved for deferral to avoid equity write-downs as a result of pension and PBOP under-recoveries in Fitchburg Gas and Electric Light Company, D.T.E. 02-83, Stamp Approval (December 20, 2002); D.T.E. 02-78, Stamp Approval (December 20, 2002).

FAS-required equity write-down that would have a material impact on its financial well-being and translate directly into higher borrowing costs, higher rates, and a potential disruption in service. D.T.E. 04-48, at 15-18. The Department also determined that the Company had established the magnitude and volatility of the pension and PBOP costs, taking into consideration the role of accounting requirements versus the Company's actions with respect to the pension and PBOP expense volatility, and demonstrated the effectiveness of the reconciling mechanism in avoiding the negative effects of the pension and PBOP volatility. D.T.E. 04-48, at 19. The Department approved Unitil's reconciling mechanism, represented by the current PAM, with certain modifications. D.T.E. 04-48, at 21-24. The PAM took effect on November 1, 2004 for the Company's gas division and on January 1, 2005 for the Company's electric division.

The Company continued to recover a portion of its pension and PBOP expense through base distribution rates until 2020. In settlements approved in D.P.U. 19-130 and D.P.U. 19-131 for the Company's electric and gas divisions, respectively, the Department allowed the full recovery through the PAM of all pension and PBOP expenses. D.P.U. 19-130, at 7; D.P.U. 19-131, at 7. The Company's electric division PAM operates through a separate tariff, with the resulting factor combined with distribution charges for billing purposes. M.D.P.U. No. 336 (electric). The Company's gas division PAM operates as a component within its local distribution adjustment clause tariff. M.D.P.U. Nos. 227, 277, §§ 3.0(7), 6.0(1) (gas).

C. Company Proposal

During the test year, the Company booked \$615,481 in pension expense and \$328,723 in PBOP expense, for a total of \$944,204, to its electric division (Exhs. Unitil-WP Flowthrough Detail, at Lines 795-798 (Excel, tab FGE Account Detail) (Rev. 4) (electric); Unitil-CGDN-10

(Rev. 4) (electric)).[146] The Company also booked $570,658 in pension expense and $431,145 in PBOP expense, for a total of $1,001,803, to its gas division (Exhs. Unitil-WP Flowthrough Detail, at Lines 707-710 (Excel, tab FGE Account Detail (Rev. 4) (gas); Unitil-CGDN-7 (Rev. 4) (gas)).

In this instant proceeding, the Company proposes to continue recovering its pension and PBOP expenses outside of base distribution rates through its PAM (Exhs. Unitil-CGDN-1, at 28 (electric); DPU 24-4 (electric); DPU 24-7 (electric); DPU 24-9 (electric); DPU 42-48 (electric); CGDN-1, at 26 (gas); DPU 20-4 (gas); DPU 20-7 (gas); DPU 20-9 (gas); DPU 34-32 (gas); Tr. 9, at 952, 972-978). Consistent with its current recovery method, the Company excluded the test-year pension and PBOP expenses of $944,204 associated with its electric division and $1,001,803 associated with its gas division from the test-year total O&M expenses (Exhs. Unitil-CGDN-10 (Rev. 4) (electric); Unitil-CGGN-7 (Rev. 4) (gas)). Unitil further adjusted its test-year electric division O&M expense by removing pension expense of $25,643 and PBOP expense of $28,507 associated with internal transmission that had been inadvertently included in the Company's initial base distribution revenue requirement (Exhs. Unitil-CGDN-10 (Rev. 4) (electric); Sch. RevReq 3-7 (Rev. 4) (electric); Unitil-WP 4.1 (Rev. 4) (electric); DPU 10-1 (electric)). The Company adjusted its test-year gas division O&M expense by removing pension expense of $8,486 and PBOP expense of $6,466 associated with base production costs that are currently embedded in distribution rates and proposed to recover these

146 Of these amounts, $25,643 in pension expense and $28,507 in PBOP expense were assigned to internal transmission (Exhs. Unitil-CGDN-10 (Rev. 4) (electric); Sch. RevReq-3-7 (Rev. 4) (electric); Unitil-WP 4.1 (Rev. 4) (electric); DPU 10-1 (electric)).

costs through the PAM (Exhs. Unitil-CGDN-1, at 26 (gas); Unitil-CGDN-7 (Rev. 4) (gas); Sch. RevReq 3-10 (Rev. 4) (gas); DPU 10-1 (gas)).

D. Positions of the Parties

The Company contends that its pension and PBOP expenses should continue to be recovered through the current PAM instead of being recovered through base distribution rates (Company Brief at 142, 148 (electric); Company Brief at 122, 127 (gas)). Unitil argues that there is no evidence to support any change in the underlying financial and accounting conditions that led the Department to initially approve pension and PBOP reconciling mechanisms back in 2003 (Company Brief at 143-144, 146-147 (electric), citing D.T.E. 03-47-A; Company Brief at 123, 125-126 (gas)). In this regard, the Company claims that the factors driving this expense remain highly variable, unpredictable, and outside the Company's control (Company Brief at 142 (electric), citing Exhs. Unitil-CGDN-1, at 90-91 (electric); DPU 24-4 (electric); Company Brief at 122 (gas), citing Exh. Unitil-CGDN-1, at 69 (gas)). In particular, the Company asserts that it experienced significant swings in its pension expense in 2014, 2015, and 2019, that its annual pension and PBOP expense decreased by approximately 50 percent in 2022, and that it expects to receive pension and PBOP income rather than incurring expense for 2023 (Company Brief at 144 (electric), citing Exh. DPU 24-4, Att. 1 (electric); Company Brief at 125 (gas)).

Additionally, Unitil contends that interest rates and capital markets, which the Company maintains are outside of its control, drive the volatility of these expense levels year to year (Company Brief at 144, 146, 275-276 (electric), citing Exhs. DPU 24-4 & Att. (electric); DPU 24-7 (electric); DPU 42-48 (electric); DPU 47-1 (electric); Tr. 9, at 972-973; Company Brief at 124-126, 228 (gas), citing Exhs. DPU 20-4 & Att. (gas); DPU 20-7 (gas); DPU 34-28 (gas); DPU 36-1 (gas)). Further, Unitil argues that transferring pension and PBOP expenses into base rates could be viewed as "credit negative"[147] by rating agencies, particularly in combination with a PBR plan that features a five-year stay-out provision, and thus weaken the Company's financial integrity, harming customers (Company Brief at 142-143, 145 (electric), citing Exh. DPU 42-28 (electric); Tr. 9, at 974-975; Company Brief at 122, 124 (gas), citing Exh. DPU 34-39 (gas)). According to Unitil, to maintain its financial integrity, it is paramount that the Department issue balanced, credit-supportive decisions to assure that the Company of timely and adequate cost recovery (Company Brief at 145 (electric), citing Exhs. Unitil-RBH-Rebuttal at 15 (electric); AG 7-45 (electric); Tr. 12, at 1170); Company Brief at 124 (gas), citing Exh. Unitil-RBH-Rebuttal at 20 (gas)). Moreover, Unitil claims that negative pressure on its credit metrics brought about by the financial community's concerns about the Massachusetts regulatory environment could result in higher borrowing costs, which in turn would lead to higher rates for customers (Company Brief at 145, 210 (electric), citing Exh. DPU 42-28 (electric); Tr. 9, at 972-975; Company Brief at 124-125, 181 (gas), citing Exh. DPU 34-39 (gas)).

Next, the Company argues that there are practical reasons why pension and PBOP costs should not be transferred into base rates (Company Brief at 147 (electric); Company Brief at 127 (gas)). Specifically, the Company asserts that there is no reasonable basis upon which to derive a

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[147] During the proceeding, Unitil stated that having very volatile costs or very volatile revenues could be seen as credit negative, and potentially lead to a credit downgrade, which in turn could signal to potential investors that the Company is riskier and would require higher borrowing costs (Exhs. DPU 24-7 (electric); DPU 42-22 (electric); DPU 42-28 (electric); DPU 20-7 (gas); DPU 34-32 (gas); DPU 34-38 (gas); Tr. 9, at 974-975).

representative level of expense to include in base distribution rates as there currently is a negative expense balance (Company Brief at 142, 147-148 (electric); Company Brief at 122, 127 (gas)). Further, the Company contends that an adjustment to rate base would be needed to capture the prefunded pension and PBOP regulatory assets and liabilities and associated ADIT, and that the excess ADIT flowback would need to be adjusted for the ADIT deficiency currently included in the PAM (Company Brief at 148 (electric); Company Brief at 127 (gas)). The Company also asserts that bad debt expense and income taxes would increase because of the higher level of distribution revenues (Company Brief at 148, citing Exh. DPU 24-9 (electric); Company Brief at 127 (gas), citing Exh. DPU 20-9 (gas)).

Finally, Unitil argues that it has a right to expect and obtain reasoned consistency in the Department's decisions (Company Brief at 146-147 (electric), citing Alliance to Protect Nantucket Sound, Inc. v. Energy Facilities Siting Board, 448 Mass. 45, 46 (2006); Duquesne v. Barash, 488 U.S. 299, 314 (1989); Company Brief at 126 (gas)). The Company contends that any departure from past precedent must be accompanied by an adequate statement of reasons, including a determination of each issue of fact or law necessary to the decision (Company Brief at 147 (electric), citing G.L. c. 30A, § 11(8); Massachusetts Institute of Technology v. Department of Public Utilities, 425 Mass. 856, 868 (1997); Costello v. Department of Public Utilities, 391 Mass. 527, 535 (1984); Town of Hamilton et al. v. Department of Public Utilities, 346 Mass. 130 (1963); NSTAR Electric Company v. Department of Public Utilities, 462 Mass. 381, 390 (2012)); Company Brief at 126 (gas)). The Company asserts that the evidence in this proceeding does not support the elimination of the PAM, but rather continues to demonstrate that a reconciling mechanism is an effective way to avoid the negative financial effects of ongoing pension and PBOP volatility (Company Brief at 147-148 (electric); Company Brief at 126-127 (gas)). No intervenor addressed this issue on brief.

E. Analysis and Findings

1. Continuation of Company PAM

The Department addressed the use of reconciling mechanisms as a ratemaking tool in D.P.U. 07-50-A at 50. In its approval of revenue decoupling mechanisms, the Department did not eliminate the use of reconciling mechanisms, noting that at the time these reconciling mechanisms were approved, we had determined that the costs to be recovered were volatile and fairly large in magnitude, were neutral to fluctuations in sales volumes, and were beyond the control of the companies. D.P.U. 07-50-A at 50; see also D.T.E. 05-27, at 183-186; D.T.E. 03-47-A at 25-28, 36-37. The Department stated that it would consider which, if any, of the costs being recovered through reconciling mechanisms should continue to be fully reconciled via those separate mechanisms or recovered, instead, via base rates as circumstances change. D.P.U. 07-50-A at 50. The Department also noted that such consideration would take place on a case-by-case basis in a base distribution rate proceeding, where the distribution company must demonstrate that continued recovery in a separate mechanism is warranted. D.P.U. 07-50-A at 50. The Department has reviewed the evidence, as discussed below, and we are persuaded that the continuation of the PAM no longer is warranted.

Contrary to the Company's claim, the Department finds that the circumstances that gave rise to the Department's approval of a reconciling mechanism for pension and PBOP costs have changed. At the time the Department issued D.T.E. 03-47-A financial accounting standards required the creation of a recovery mechanism for pension and PBOP deferrals over a reasonable period for companies to treat these deferrals as regulatory assets. D.T.E. 03-47-A at 20-21. In the absence of such a recovery mechanism, companies would have been required to write down their common equity in an amount equal to the sum of the after-tax cost of both the additional minimum liability and the pension and PBOP deferral. D.T.E. 03-47-A at 21. The subsequent adoption of FAS 158 and legislation in the form of the Pension Protection Act of 2006 ("PPA")[148] have addressed the concern that financial accounting requirements could have a detrimental impact on shareholders' equity and thereby largely removed any financial accounting reasons for these costs to be recovered outside of base distribution rates. Specifically, shortly after the PPA was signed into law on August 17, 2006, FAS 158 was issued in September 2006, requiring companies to recognize their retirement plan funding status on their financial statements as an asset or liability (Exhs. DPU 24-8 (electric); DPU 24-13 (electric); DPU 20-8 (gas); DPU 20-13 (gas)). At the time, the implications of FAS 158 in pension and PAF proceedings were focused on certain aspects of FAS 158, such as carrying charges associated with prepaid pension and PBOP balances and the changeover to calendar year measurement periods for actuarial valuations. New England Gas Company, D.P.U. 08-66/D.P.U. 09-83, at 22-24 (2010); Fitchburg Gas and Electric Light Company, D.P.U. 07-78-A at 2-8 (2008).

8Similarly, consideration of the PPA in pension and PBOP proceedings focused on changes in minimum funding levels brought about by the PPA. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 11-14-A at 11 (2014). In this proceeding, the

[148] The PPA provides that a plan is considered endangered if it is less than 80 percent funded and is projected to have a funding deficiency within seven years, in which case such plan would have ten years to rectify its funding deficiency. 29 U.S.C. § 1085.

Department developed a full evidentiary record regarding the implications of FAS 158 and the PPA on the Company's PAM, in a manner more comprehensive than that feasible in a PAM reconciliation proceeding. Based on the evidence and our analysis of the evidentiary record, the Department concludes that the implementation of FAS 158 and enactment of the PPA, with their attendant effect on utility companies' financial reporting on pension and PBOP plan funded status, eliminated the potential for an equity write-down and, in turn, resolved concerns regarding significant and impairing financial consequences and adverse effects on customers as described by the Department in D.P.U. 03-47-A at 25-27. See Summary of Statement No. 158.

Moreover, the Department finds that the actuarial assumptions determining the annual pension and PBOP expenses are not entirely outside of the Company's control. Specifically, the interest rates (i.e., discount rates and return on plan assets), which are the major factors among the actuarial assumptions used for calculating pension and PBOP expenses, are chosen by the Company (Exhs. DPU 24-4 (electric); DPU 24-13 (electric); DPU 42-19 (electric); DPU 42-24 (electric); DPU 42-28 (electric); DPU 20-4 (gas); DPU 20-13 (gas); DPU 34-29 (gas); DPU 34-34 (gas); DPU 34-38 (gas); Tr. 9, at 967-968). Unitil determines the appropriate discount rates and its estimate of the rate of return on investment, along with other actuarial assumptions such as future compensation and health care cost trend rates, annually based on internal meetings and discussions with its external actuary (Tr. 9, at 967-970). The assumptions developed through this process are then used in the actuarial calculations that determine the Company's pension and PBOP expenses presented in its annual actuarial reports (Exhs. DPU 42-19 (electric); DPU 34-29 (gas); AG 1-48, Atts. 1, at 16, 2, at 17, 3, at 16, 4, at 17, 5, at 17, 6, at 17 (electric); AG 1-48, Atts. 1, at 16, 2, at 17, 3, at 16, 4, at 17, 5, at 16, 6, at 17 (gas); RR-DPU-42, Atts. 1, at 16, 2, at 17 (electric); RR-DPU-42, Att. 1, at 16, Att. 2, at 17 (gas)). Unitil recognizes the role these estimates have in determining pension and PBOP expenses (Exh. Filing Requirements Section III.B.4, Att. 8, at 51-52; Tr. 9, at 967-970).

Additionally, the Department is not persuaded that changing the recovery method of pension and PBOP costs would adversely affect the Company's credit ratings and cause undue burden to ratepayers. In particular, the Company states that recovering pension and PBOP expenses through base distribution rates would ultimately cause an undue burden to ratepayers because the credit rating agencies would view it as credit negative due to swings in earnings and cash flow, leading to a credit downgrade and thereafter to higher borrowing costs (Exhs. DPU 24-7 (electric); DPU 42-22 (electric); DPU 42-28 (electric); Company Brief at 142-143, 145 (electric); DPU 20-7 (gas); DPU 34-32 (gas); DPU 34-38 (gas); Company Brief at 122, 124 (gas); Tr. 9, at 973-975). We are not persuaded, however, that eliminating dollar-for-dollar recovery of these expenses would necessarily result in a credit downgrade, particularly if a representative level of pension and PBOP costs were recovered through base distribution rates (<u>see</u> Exhs. DPU 42-22 (electric); DPU 34-32 (gas)). Further, the Department is not convinced that moving pension and PBOP cost recovery to base distribution rates would cause swings in the Company's earnings and cash flow that could negatively impact its credit standing and harm customers. Unitil's test-year PAM revenues of $845,426 for its electric division represented about 0.95 percent of its total electric operating revenues of $88,963,526 (Exh. Sch. RevReq-1, at 2 (Rev. 4)). Unitil's test-year PAM revenues of $908,418 for its gas division represented about 1.9 percent of its total gas operating revenues of $47,823,978 (Exh. Sch. RevReq-1, at 2 (Rev. 4)). Further, the Department acknowledges that while there have been fluctuations in the overall pension and PBOP expenses since 2004 (Exhs. DPU 24-4, Att. 1 (electric); DPU 20-4, Att. 1 (gas)), the actual factors themselves consistently have remained relatively small, as demonstrated in the Company's experience with its PAM factors for its residential rate classes. Since 2020, when the Company moved all of its pension and PBOP expense out of base rates, the Company's electric division residential PAM factors have ranged from $0.00236 per kilowatt-hour ("kWh") to $0.00333 per kWh. D.P.U. 23-76, at 2; D.P.U. 22-97, Stamp approval at 2 (December 16, 2022); D.P.U. 21-94, at 3; D.P.U. 20-87, at 3. Although the values of the factors have fluctuated from year to year, they have remained low over this period. This same pattern is exhibited by the PAM factors for the Company's other electric division rate classes. D.P.U. 23-76, at 2; D.P.U. 22-97, Stamp Approval (December 16, 2022); D.P.U. 21-94, at 3; D.P.U. 20-87, at 3.

The Company's gas division PAMs exhibit a similar pattern. Since 2020, the Company's gas division residential PAM factors have ranged from $0.0450 per therm to $0.0597 per therm. Fitchburg Gas and Electric Light Company, D.P.U. 23-PGAF-FGE at 2 (2023); Fitchburg Gas and Electric Light Company, D.P.U. 22-PGAF-FGE at 2 (2023); Fitchburg Gas and Electric Light Company, D.P.U. 21-GAF-P4, at 2 (2021); Fitchburg Gas and Electric Light Company, D.P.U. 20-GAF-P4, at 2 (2020). Although the value of the factors have fluctuated from year to year, they have remained low over this period. This same pattern is exhibited by the PAM factors for the Company's other gas division rate classes. D.P.U. 23-PGAF-FGE at 2; D.P.U. 22-PGAF-FGE at 2; D.P.U. 21-GAF-P4, at 2; D.P.U. 20-GAF-P4, at 2. Based on the foregoing considerations, we are not persuaded that base distribution rate recovery of pension and PBOP expenses would reflexively lead to downgrades by credit agencies and potential adverse impacts for Unitil and its customers, given the relatively moderate amounts involved.

Regarding market conditions, while the Department recognizes that the Company does not have control over the financial markets, we find that our ratemaking policies mitigate the effects of economic fluctuations. In particular, as discussed in Section III.D.5.a. above, the Department has approved five-year PBR plans for the Company's operating divisions. The annual PBR adjustments under the plans are designed to provide the Company with sufficient revenue to navigate inflationary and other economic pressures. Consequently, recovering pension and PBOP expenses through base distribution rates would neither benefit nor punish the Company under the terms of the PBR plans being approved here (Exhs. DPU 24-9 (electric); DPU 42-24 (electric); DPU 20-9 (gas); DPU 34-34 (gas)).

Finally, we note that PAM filings have become increasingly complex, resource-intensive, and administratively inefficient over the years. For example, it currently takes two years for the Company to present one year of FAS-determined pension and PBOP expenses (Exhs. DPU 42-28 (electric); DPU 34-38 (gas); Tr. 9, at 953-957 (electric); Tr. 9, at 953-957 (gas)). See also D.P.U. 23-76; D.P.U. 22-97; D.P.U. 21-94; D.P.U. 20-87.

For the foregoing reasons, the Department finds that allowing the Company to recover pension and PBOP expense through the PAM is no longer warranted. Instead, we conclude that these expenses should be recovered in base distribution rates and moreover that the PAM should be discontinued, consistent with our additional findings below. We recognize that parties have a right to expect and obtain reasoned consistency in our decisions. See, e.g., Boston Gas Company v. Department of Public Utilities, 367 Mass. 92, 104 (1975) (parties have a right to expect and obtain reasoned consistency in agency's decision); Tofias v. Energy Facilities Siting Board, 435 Mass. 340, 349 (2001) (party to a proceeding before a regulatory agency has a right to expect and obtain reasoned consistency in agency decision). The doctrine of reasoned consistency, however, does not mean that an agency may never deviate from its original position, but rather means only that any change from an established pattern of conduct must be explained. Alliance to Protect Nantucket Sound, Inc. v. Department of Public Utilities, 461 Mass. 166, 175 (2011). The Department has set forth its reasons, supported by the evidentiary record, for our decision to discontinue the PAM. Our decision here is based on our full consideration of the evidentiary record developed in these proceedings; the issue of whether other companies may continue to recover pension and PBOP expense through a reconciling mechanism will be determined on a case-by-case basis.

2. Base Distribution Rate Recovery

The Department has not endorsed a specific method for the calculation of pension and PBOP expenses for ratemaking purposes but has always sought to include an amount that results in just and reasonable rates. D.P.U. 03-47-A; D.P.U. 96-50 (Phase I) at 81; D.P.U. 89-81, at 33-34. In setting rates, the Department's scope of decision is not bound by a single method. Massachusetts Electric, 376 Mass. 294, 302; Verizon Massachusetts, D.T.E. 01-31 (Phase II) at 72 (2003), citing American Hoechest, 379 Mass. 408, 413; New England Telephone & Telegraph Company v. Department of Public Utilities, 371 Mass. 67, 71 (1976).

In deriving a representative level of pension and PBOP expense, the Department has considered Unitil's cash contributions to its pension and PBOP plans, including the additional pension contribution made in 2018 as discussed in Section V.E. above (Exhs. DPU 24-5, Att. 1

(electric); DPU 20-5, Att. 1 (gas); AG 1-49, Atts. 1-4). The Employee Retirement Income Security Act establishes the minimum funding requirement for pension contributions, and the PPA provides comprehensive guidance on the timing of the pension contributions needed to maintain the employer-sponsored retirement plans. 29 U.S.C. § 18; 26 U.S.C. § 401; 26 C.F.R. § 11.412(c); 26 C.F.R. § 412; 26 C.F.R. § 430. Under FASB accounting rules, the cash contributions decrease the liability balance on the balance sheet and the FAS-determined pension and PBOP expenses increase the expense on the income statement, while both cash contributions and FAS-determined pension and PBOP expenses represent the same costs for the employer-sponsored pension and PBOP plans. Since its PAM approval, the Company has been recovering the pension and PBOP costs based on the FAS-determined pension and PBOP expenses that reflect the actuarial assumptions and delayed recognition of the benefit plan changes in future years (Exhs. AG 1-48, Atts. 1-6; AG 1-49, Atts 1-4.).[149]

The Department finds that basing the representative level of pension and PBOP expense on cash contributions to the Company's pension and PBOP trusts would not produce a representative level of pension and PBOP expense to include in base distribution rates. The Company's pension cash contributions including that allocated from USC have ranged between $1,296,815 and $4,037,094 during 2018 through 2022, and its PBOP cash contribution has increased from $1,428,524 in 2018 to $10,060,129 in 2022, when the Company made a sizable PBOP cash contribution to decrease its PBOP liabilities and to obtain a tax benefit (Exhs. DPU 10-8 (electric); DPU 24-5, Att. (electric); DPU 10-9 (gas); DPU 20-5, Att. (gas)).

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149 In particular, the components of the net periodic pension costs are presented in Exhibit AG 1-48, Att. 1, at 7.

Therefore, cash contributions are not reliable for determining the amount to be included in the cost of service.

In contrast, under FAS 87 and FAS 106, a company's FAS-determined pension and PBOP expenses are recorded on an accrual accounting basis and deferred until the benefits are actually paid, so these accruals would not affect the Company's cash flow. The Department considers accrual accounting as being integral to the ratemaking process because it provides a reasonable approximation of a company's eventual actual expenses, resulting in a generally accepted matching of expenses. Western Massachusetts Electric Company, D.P.U. 84-25, at 68-69 (1984); D.P.U. 10-70, at 184; The Berkshire Gas Company, D.P.U. 1490, at 37 (1983). In view of the current PAM mechanism providing for a three-year recovery of pension and PBOP expense, the Department finds it reasonable and appropriate to use Unitil's three-year average FAS-determined pension and PBOP expenses as a representative level of pension and PBOP expense, as discussed below. M.D.P.U. No. 336, § 1.05 (electric); M.D.P.U. No. 227, § 1.05 (gas).[150]

For the electric division, the Company recorded direct pension expense of $845,484 for 2021, $437,400 for the test-year, and negative $153,048 for 2023 (Exh. AG 1-34, Att. 2, at 20 (electric); RR-DPU-41, Att.1, at 18 (electric)). The three-year average direct expense, exclusive of 54.36 percent of capitalization, is $171,886[151] (Exh. Unitil-WP Allocator (Rev. 4) (electric)).

150 The Department notes that the Company's pension and PBOP expense recovery has been on the terms of one-third of the expense each year on a deferral basis since the PAM went into effect. M.D.P.U. No. 336, § 1.05 (electric); M.D.P.U. No. 227, § 1.05 (gas). See D.P.U. 23-76; D.P.U. 22-97; D.P.U. 21-94; D.P.U. 20-87.

151 ($845,484 + $437,400 - $153,048) ÷ 3 × (1 – 54.36%) = $171,886

For pension expense allocated from USC, the Company recorded $387,084 for 2021, $167,304 for the test year, and negative $53,064 for 2023 (Exh. AG 1-34, Att. 2, at 23 (electric); RR-DPU-40, Att. 1, at 20, 21 (electric)). The three-year average allocated pension expense, exclusive of 24.77 percent capitalization, is $125,896[152] (Exh. Unitil-WP Allocator (Rev. 4) (electric)). The sum of the total direct and allocated pension expense is $297,782, which is further reduced by 5.1021 percent for amounts assigned to internal transmission, resulting in pension expense associated with base distribution for the Company's electric division of $282,589.[153]

Regarding PBOP expense for the electric division, the Company recorded direct PBOP expense of $884,940 for 2021, $581,580 for the test-year, and negative $86,472 for 2023 (Exh. AG 1-34, Att. 2, at 20 (electric); RR-DPU-41, Att. 1, at 18 (electric)). The three-year average direct expense, exclusive of 54.36 percent of capitalization, is $209,951[154] (Exh. Unitil-WP Allocator (Rev. 4) (electric)). For PBOP expense allocated from USC, the Company recorded $163,032 for 2021, $142,332 for the test-year, and negative $36,060 for 2023 (Exh. AG 1-34, Att. 2, at 23 (electric); RR-DPU-40, Att. 1, at 20, 21 (electric)). The three-year average allocated pension expense, exclusive of 24.77 percent capitalization, is $67,532[155] (Exh. Unitil-WP Allocator (Rev. 4) (electric)). The sum of the total direct and allocated PBOP

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152 ($387,084 + $167,304 - $53,064) ÷ 3 × (1- 24.77%) = $125,896

153 ($171,886 + $125,896) × (1 – 5.1021%) = $282,589

154 ($884,940 + $581,580 - $86,472) ÷ 3 × (1 – 54.36%) = $209,951

155 ($163,032 + $142,332 - $36,060) ÷ 3 × (1- 24.77%) = $67,532

expense is $277,483, which is further reduced by 5.1021 percent for amounts assigned to internal transmission, resulting in PBOP expense associated with base distribution for the Company's electric division of $263,326.[156]

For the gas division, the Company recorded direct pension expense of $764,964 for 2021, $415,224 for the test-year, and negative $154,884 for 2023 (Exh. AG 1-34, Att. 2, at 5 (gas); RR-DPU-41, Att.1, at 5 (gas)). The three-year average direct expense, exclusive of 54.36 percent of capitalization, is $155,983[157] (Exh. Unitil-WP Allocator (Rev. 4) (gas)). For pension expense allocated from USC, the Company recorded $255,180 for 2021, $117,312 for the test-year, and negative $38,904 for 2023 (Exh. AG 1-34, Att. 2, at 8 (gas); RR-DPU-40, Att. 1, at 7 (gas)). The three-year average allocated pension expense exclusive of 31.44 percent capitalization is $76,236[158] (Exh. Unitil-WP Allocator (Rev. 4) (gas)). The sum of the total direct and allocated pension expense associated with base distribution for the Company's gas division is $232,219.

Regarding PBOP expense for the gas division, the Company recorded direct PBOP expense of $800,664 for 2021, $552,096 for the test-year, and negative $87,528 for 2023 (Exh. AG 1-34, Att. 2, at 6 (gas); RR-DPU-41, Att.1, at 5 (gas)). The three-year average direct expense, exclusive of 54.36 percent of capitalization, is $192,484[159] (Exh. Unitil-WP

156 ($209,951 + $67,532) × (1 – 5.1021%) = $263,326

157 ($764,964 + $415,224 - $154,884) ÷ 3 × (1 – 54.36%) = $155,983

158 ($255,180 + $117,312 - $38,904) ÷ 3 × (1- 31.44%) = $76,236

159 ($800,664 + $552,096 - $87,528) ÷ 3 × (1 – 54.36%) = $192,484

Allocator (Rev. 4) (gas)). For PBOP expense allocated from USC, the Company recorded $107,268 for 2021, $99,792 for the test-year, and negative $26,436 for 2023 (Exh. AG 1-34, Att. 2, at 8 (gas); RR-DPU-40, Att. 1, at 7 (gas)). The three-year average allocated pension expense exclusive of 31.44 percent capitalization is $41,279[160] (Exh. Unitil-WP Allocator (Rev. 4) (gas)). The sum of the total direct and allocated PBOP expense is $233,763 for the Company's gas division.

Based on the above findings, the Department increases the Company's proposed cost of service for its electric division by $545,915, based on the representative level of pension expense (i.e., $282,589) and PBOP expense (i.e., $263,326). The Department increases the Company's proposed cost of service for its gas division by $465,982, based on the representative level of pension expense (i.e., $232,219) and PBOP expense (i.e., $233,763).

3. PAM Phase Out and Discontinuance

The Company's current pension and PBOP cost recovery through the PAM operates on a three-year deferral basis and the Company recovers one-third of the cost each year. See generally D.P.U. 23-76; D.P.U. 22-97; D.P.U. 21-94; D.P.U. 20-87. As such, we find that it is appropriate to discontinue the PAM through a phase out as follows. The Company is allowed to recover the remaining balance of the unamortized pension and PBOP expenses in the amount of one-half of the total balance through the next two PAM filings. The total balance shall include: (1) one-half of the unamortized pension and PBOP expense deferral as of December 31, 2024; (2) one-half of the unamortized 2023 pension and PBOP expense deferral; and (3) the under- or

160 ($107,268 + $99,792 - $26,436) ÷ 3 × (1- 31.44%) = $41,279

over-recovery through the Company's PAF as of the reconciliation date. The unamortized pension and PBOP expense deferral as of December 31, 2024 is the amount of unamortized reconciliation deferral as of December 31, 2023, subtracting the amount of reconciliation adjustment for 2024 as filed in D.P.U. 23-76, Exh. Sch. PAF-1, at 2, Lines 6, 7 (Rev.). The unamortized 2023 pension and PBOP expense deferral is the difference between the amount of FAS-determined 2023 pension and PBOP expenses and the 2023 pension and PBOP expenses filed in D.P.U. 23-76, Exh. Sch. PAF-1, at 2, Line 3 (Rev.). The under- or over-recovery through the Company's PAF as of December 31, 2024 will be calculated using the prime rate filed in the next PAM filing as illustrated in D.P.U. 23-76, Exh. Sch. PAF-5 (Rev.). 220 CMR 6.08. Beginning from the next PAM filing, the Company will no longer recover carrying charges on pension and PBOP deferrals and prepaid pension and PBOP amounts because the Company's carrying charges calculated in D.P.U. 23-76 were based on the 2023 year-end balance and its deferral included estimated 2023 cost recovery. D.P.U. 23-76, Exh. Sch. PAF-1, at 2-4 (Rev.). The Department directs the Company to remove the 2024 pension and PBOP expense in the Company's next PAM filing, and to include one-half of the 2024 FAS-determined pension and PBOP expenses, representing the pension and PBOP expenses for the period of January 1, 2024 through June 30, 2024 for its electric and gas division, respectively, in the final PAM filing in 2025 (Exhs. DPU 42-28 (electric); DPU 34-38 (gas)). Unitil shall keep contemporaneous records for the PAM phase-out period for the Department's review in the Company's next base distribution rate case. The Company shall file a compliance filing with revised tariffs to become effective July 1, 2024, that comply with this Order for the electric division and gas division, respectively.

VIII. VEGETATION MANAGEMENT AND STORM RESILIENCY PROGRAMS

A. Introduction

Unitil has instituted a two-pronged approach to enhance and protect the reliability of its distribution system from the effects of trees and other vegetation: the Vegetation Management Program ("VMP") and the SRP (Exh. Unitil-SMS-1, at 3 (electric)). Each of these programs is discussed below.

B. Vegetation Management Program

1. Introduction

The Company's VMP was implemented in 2012 and is designed to meet the state's regulatory targets and expectations as well as to increase customer satisfaction through improved reliability performance (Exh. Unitil-SMS-1, at 7 (electric)). D.P.U. 13-90, at 110. Unitil's VMP consists of three primary components: cycle pruning,[161] hazard tree[162] mitigation, and forestry reliability assessment[163] (Exh. Unitil-SMS-1, at 5 (electric)). The Company states that each of these three components is intended to minimize the potential for tree and vegetation contact with

161 Cycle pruning is vegetation pruning and clearing performed on a cyclical schedule (Exh. Unitil-SMS-1, at 5 (electric)). The Company recently transitioned from a four-year cycle to a five-year cycle to focus its efforts and resources on increased hazard tree removal (Exh. Unitil-SMS-1, at 5 (electric)).

162 A hazard tree is any tree which, on failure, is capable of interfering with the safe, reliable distribution of electricity that has both a target and a noticeable defect that increases the likelihood of failure (Exh. Unitil-SMS-1, at 6 (electric)). Hazard trees may be identified during the five-year pruning cycle, as part of mid-cycle assessments, or based on field conditions (Exh. Unitil-SMS-1, at 6 (electric)).

163 The forestry reliability assessment component targets circuits for inspection, pruning, and hazard tree removal based on recent historical reliability performance (Exh. Unitil-SMS-1, at 6 (electric)).

overhead utility lines and the distribution system damage that could result (Exh. Unitil-SMS-1, at 5 (electric)).

The Company's VMP also has a sub-transmission maintenance component that focuses on maintaining the rights of way that connect substations together (Exh. Unitil-SMS-1, at 8 (electric)). The sub-transmission maintenance activities include identifying compatible and incompatible vegetation, considering action thresholds, evaluating control methods, and selecting and implementing controls to achieve a specific objective (Exh. Unitil-SMS-1, at 8 (electric)). In addition, the VMP has a non-discretionary (or core work) component that enables the Company to respond to unscheduled activities such as emergencies, customer requests, new construction needs, and other non-discretionary and unscheduled work (Exh. Unitil-SMS-1, at 7 (electric)). Due to the inherent variability of core work conducted under the VMP, costs related to core work can vary significantly because of frequent minor weather events or large weather events (Exh. Unitil-SMS-1, at 8 (electric)).

The Company states that VMP costs are primarily driven by the cost to implement cycle pruning, which is the largest VMP component (Exh. Unitil-SMS-1, at 9 (electric)). Other factors that affect the VMP costs overall are high tree density, high customer density per mile, overall forest health, scenic road designations, traffic control/work protection requirements, and work-force retention (Exh. Unitil-SMS-1, at 9 (electric)).

In D.P.U. 13-90, at 115-116, the Department permitted the Company to include appropriate test-year costs for VMP in its base distribution rates with no carrying costs. In D.P.U. 15-80/D.P.U. 15-81, at 145, the Department again permitted the Company to include test-year costs for VMP in its base distribution rates with no carrying costs.

2. Company Proposal

The Company proposes to continue its VMP without any substantive changes to its program or cost recovery. During the test year, the Company booked $1,941,472 in costs related to its VMP (Exhs. Unitil-SMS-1, at 9 (electric); Unitil-SMS-2, line 16 (electric)). The Company proposes to remove an out-of-period adjustment of $120,908 (Exhs. Unitil-SMS-1, at 9 (electric); Unitil-SMS-2, line 17 (electric); Sch. RevReq-3-11 (Rev. 4) (electric); DPU 11-6 (electric)).[164] As a result, the Company proposes to include in its cost of service $1,820,564 of VMP expenses (Exhs. Unitil-SMS-2, line 18 (electric); DPU 11-8, Att. (electric)).

3. Positions of the Parties

The Company asserts that its comprehensive VMP is designed to cost-effectively address the different risk and provide benefits to customers, support reliability, and provide a measure of public safety (Company Brief at 292 (electric), citing Exh. Unitil-SMS-1, at 3-4 (electric)). No intervenor commented on the Company's VMP on brief.

4. Analysis and Findings

It is well-established Department precedent that base distribution rates are based on an historic test year, adjusted for known and measurable changes. D.P.U. 1580, at 13-17, 19; D.P.U. 136, at 3-5; D.P.U. 18204, at 4-5; D.P.U. 18210, at 2-3; see also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). The Company proposes to include in its cost of service its test-year VMP costs of $1,820,564. Based on the record

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164 The $120,908 represents an accrual entry to match-up expenses and revenue related to VMP activities. The $120,908 is not related to 2022 VMP expenses and, as such, has been removed by the Company (Exh. DPU 11-6 (electric)).

evidence, we find that the test-year VMP expense is a representative level of expense (Exh. DPU 11-8, Att. 1 (electric)). Therefore, we accept the Company's proposal to include its test-year costs of $1,820,564 in its cost of service.

C. Storm Resiliency Program

1. Introduction

The Company implemented its SRP in 2014 (Exh. Unitil-SMS-1, at 20). D.P.U. 13-90, at 19-20. Unitil states that its SRP is intended to reduce tree-related incidents and the resulting customer interruptions, as well as impacts to municipalities and critical facilities (such as hospitals, police, and fire stations) along critical portions of targeted lines in minor and major weather events[165] (Exh. Unitil-SMS-1, at 15, 17 (electric)). D.P.U. 13-90, at 15. Unitil's SRP was designed to target trees outside the scope of the VMP and to focus on removing all overhanging vegetation (i.e., ground-to-sky clearing) on critical three-phase sections of select circuits as well as performing intensive hazard tree review and removal (Exh. Unitil-SMS-1, at 15, 22 (electric)). D.P.U. 13-90, at 15. The SRP involves the removal of all tree exposure to lines (Exh. Unitil-SMS-1, at 17). The Company's specifications are to remove all overhanging branches and limbs from above the conductors and ten feet to either side (Exh. Unitil-SMS-1, at 17-18 (electric)).

Initially, the Department permitted the Company to collect $501,445 annually in base distribution rates and to recover any SRP balance in its next base distribution rate case without

165 "Major weather events" are defined by the Company as weather events above normal conditions such as massive snowstorms, and storms with wind above 50 mph where the failure of defective trees and limbs predominate, and widespread and extended outages occur. D.P.U. 13-90, at 15.

carrying costs. D.P.U. 13-90, at 21.[166] In the Company's next two base distribution rate cases, the Department allowed the SRP to continue as a pilot program, at the same funding level of $501,445 and to recover any SRP balance in its next base distribution rate case without carrying costs. D.P.U. 15-80/D.P.U. 15-81, at 61; D.P.U. 19-130, at 6, 15-16. From the implementation of the SRP in 2014 through December 31, 2022, the Company accrued an under-collection balance of $446,367 in SRP costs (Exhs. Unitil-SMS-1, at 21 (electric); Unitil-SMS-4 (electric); DPU 11-9 (electric); DPU 11-10, Att. (electric)).[167]

2. Company Proposal

The Company proposes to continue its SRP with modifications to cost recovery. The Company booked $666,096 in test-year costs related to its SRP (Exhs. Unitil-SMS-1, at 21 (electric); Unitil-SMS-3, line 6 (electric); DPU 11-11 (electric)).[168] The Company proposes to include in its cost of service the test-year amount of $666,096 (Exhs. Unitil-SMS-3, line 6 (electric); Sch. RevReq-3-11 (Rev. 4) (electric); DPU 11-9 (electric)). In addition, the Company proposes a new reconciling mechanism to: (1) recover the under-recovered amount of $446,367; and (2) annually reconcile the amount of SRP funding in base distribution rates to actual SRP

166 The $501,445 was based on implementing an SRP on approximately 9.2 miles of circuits annually. D.P.U. 13-90, at 16-17.

167 Between 2014 through December 31, 2022, the Company incurred $4,753,921 in SRP costs and collected $4,307,555 through base distribution rates (Exh. DPU 11-10, Att. (electric)). The $446,367 represents the SRP under-collection sought for recovery (Exh. DPU 11-10, Att. (electric)).

168 The test-year SRP amount comprises: (1) $74,972 of USC planning and oversight; (2) $43,491 related to field implementation; (3) $495,419 related to storm hardening activities to clear vegetation from ground to sky and to remove hazard trees; and (4) $52,215 related to traffic control (Exhs. Unitil-SMS-3 (electric); DPU 11-9 (electric)).

costs (Exhs. Unitil-SMS-1, at 21 (electric); Unitil-SMS-4 (electric); proposed tariff M.D.P.U. No. 410 (electric)). Unitil proposes to submit its reconciling filing annually for rates effective January 1 (proposed tariff M.D.P.U. No. 410 (electric)). The Company proposes that the monthly balance in its reconciliation account accrue carrying charges at the prime rate (proposed M.D.P.U. No. 410 (electric)).

3. Positions of the Parties

The Company contends that the SRP is a critical program given that its system infrastructure is unavoidably exposed to dense vegetation growing alongside the overhead electric lines and is exposed to many different weather events that can cause substantial damage and prolonged power interruptions (Company Brief at 291-292 (electric)). The Company maintains that, through its SRP, it has made significant progress in reducing tree exposure along electric overhead lines to reduce the overall cost of storm preparation and response and improve system performance during major storm events (Company Brief at 292 (electric)). No intervenor commented on the Company's SRP on brief.

4. Analysis and Findings

As an initial matter, we recognize the impact that the SRP has had on the Company's system reliability (Exhs. Unitil-SMS-1, at 4, 20-21; DPU 43-3 (electric); DPU 50-10 (electric)). There has been an improvement trend in circuit performance for service quality requirements, with the SRP circuits substantially outperforming the non-SRP circuits (Exhs. Unitil-SMS-1, at 4, 20-21; DPU 11-13 (electric)). As such, the Department acknowledges the importance of allowing the SRP to continue.[169]

We next consider the appropriateness of granting Unitil's proposal to implement a new reconciling mechanism for its SRP. The Department has seen a proliferation of reconciling mechanisms, including for storm costs, capital expenditures, Attorney General consultant costs, electric vehicle ("EV") programs, and residential assistance. The Department has stated that we will give careful consideration to the formation of any new fully reconciling cost mechanism. D.P.U. 11-01/D.P.U. 11-02, at 364; D.P.U. 10-70, at 48; D.P.U. 10-55, at 66 n.43. Specific criteria the Department considers when determining whether to allow a new fully reconciling mechanism include whether the costs at issue are: (1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the company's control. D.P.U. 10-55, at 66 n.43; D.T.E. 05-27, at 183-186. Based on the record evidence, SRP costs have remained relatively stable over the past several years and thus are not volatile in nature (Exh. Unitil-SMS-4 (electric)). Since 2014, the average annual deviation of SRP expenditures to those recovered in the cost of service is approximately $52,000.[170] The Department finds this deviation is not large in magnitude and, as such, does not warrant the administrative burden of reconciling these costs. In addition, the Department is concerned that implementing a reconciling mechanism could

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169 To date, the SRP has been referred to as a "pilot" program. D.P.U. 15-80/D.P.U. 15-81, at 61; D.P.U. 13-90, at 20. Based on the extent of the SRP's historical performance, the SRP shall no longer be designated as a "pilot" program.

170 To derive the $52,000, the Department divided the under-collected amount of $446,367 by the 8.6 years of program activity.

remove an incentive for the Company to control the SRP costs. Therefore, the Department rejects the Company's proposal to implement an SRP reconciling mechanism.

The Company had proposed to recover $446,367 in accrued under-collected amounts through its new reconciling mechanism. In D.P.U. 15-80/D.P.U. 15-81, at 61, we required that in its next base distribution rate case, the Company demonstrate that any under-collected SRP costs were incremental to costs recovered through base distribution rates, were reasonable, and were prudently incurred. The Department has reviewed the Company's annual allowed SRP costs ($501,445 per year collected in base rates) to actual SRP spending from 2014 through 2022 and confirms that, over this period, the Company has in fact under-collected $446,367 of SRP costs (Exh. DPU 11-10, Att. (electric)). Based on the record evidence, we find that such under-collected costs are incremental to that allowed, are reasonable, and were prudently incurred (Exhs. DPU 11-10, Att. (electric); DPU 27-2 (electric); DPU 27-3 (electric); DPU 30-5 (electric)). Because we denied implementation of an SRP reconciling mechanism, the Department finds it appropriate to permit recovery of the accrued SRP under-collection through base distribution rates with $446,367 amortized over the Company's five-year PBR plan. Thus, we will increase the Company's SRP cost of service by $89,273.[171]

The Department next considers the annual amount of SRP funding to collect in base distribution rates. The Company proposes to include the test-year SRP costs of $666,096 in the cost of service (Exh. Sch. RevReq-3-11 (Rev. 4) (electric)). As noted above, SRP costs have remained relatively stable over the past several years (Exh. Unitil-SMS-4 (electric)). Therefore,

171 $446,367 divided by five = $89,273

we accept the Company's proposal to include the test-year SRP costs of $666,096 in its cost of service.

D. Conclusion

The Department has long recognized the importance of electric and gas utilities providing safe and reliable service to customers. And we have previously determined that vegetation management is an important factor contributing to an EDC's system reliability. D.P.U. 17-05, at 579; D.P.U. 15-155, at 328; D.P.U. 13-90, at 19. The Department encourages Unitil to work collaboratively with other EDCs in Massachusetts to create a more comprehensive approach to address overall forest health. Effective vegetation management programs are vital in maintaining a safe and reliable electric grid and the importance of maintaining forest health (such as retaining the ecological functions of trees and vegetation), in turn, is vital to the local environment. Collaboration between the EDCs and the sharing of vegetation management best practices can both reduce the risk to company infrastructure and maintain healthy forests.

IX. STORM COST RECOVERY MECHANISM

A. Introduction

Unitil's storm fund was approved in D.P.U. 19-130 as a provision in its base distribution rate settlement ("Settlement"). D.P.U. 19-130, at 5-6 & n.6. The Settlement directed the Company to implement a storm fund, effective November 1, 2020, with the same elements as the storm funds approved by the Department for National Grid (electric) in D.P.U 18-150 and NSTAR Electric in D.P.U. 17-05. D.P.U. 19-130, at 6 & n.6; Settlement at §§ 1.2.6.1 through 1.2.6.3. Specifically, the Company's approved storm fund includes: (1) a storm-fund-eligible event cost threshold to access the storm fund of $25,000 in incremental O&M expenses, with a cap of $350,000 per storm-fund-eligible event;[172] (2) an annual contribution to the fund of $140,000 per year collected through base distribution rates; (3) annual recovery through base distribution rates of $50,000 in incremental O&M expenses to represent the threshold costs of an average of two storm-fund-eligible events per year; (4) the allowance for the storm fund balance to accrue carrying charges at the prime rate, beginning at the time the costs are incurred (i.e., the receipt of invoices for such charges); (5) the creation of a Storm Reserve Adjustment Clause ("SRAC"), which provides a means to recover or refund costs incurred on and after November 1, 2020, and in excess of the amount collected in base distribution rates, through a per kWh storm reserve adjustment factor ("SRAF");[173] and (6) deferral of the recovery of incremental O&M storm costs over $350,000 per storm ("exogenous storm costs"), with carrying charges accrued at the prime rate, beginning at the time of cost incurrence. D.P.U. 19-130, at 6 & n.6, citing Settlement at §§ 1.2.6.4 through 1.2.6.7. Further, as part of the Settlement, Unitil may seek recovery of the exogenous storm costs through a separate filing or as part of the Company's next base distribution rate case (Exh. Unitil-CGDN-1, at 46 (electric)). See also D.P.U. 19-130, at 6 n.6 & Settlement at § 1.2.6.7).[174]

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[172] A storm-fund-eligible event is one with total incremental O&M storm restoration expense that exceeds the storm fund eligible event threshold of $25,000 but does not exceed the current cap of $350,000 in total incremental O&M costs. D.P.U. 19-130, at 5-6 n.6.

[173] The current tariff was approved in Fitchburg Gas and Electric Light Company, D.P.U. 23-136 (Phase I) at 6-8 (2023). M.D.P.U. No. 421A (electric).

[174] In D.P.U. 23-136 (Phase I) at 3-5, in addition to storm-fund-eligible events, the Company sought Department approval for cost recovery, through the SRAC, of two storm events that exceeded $350,000 in incremental O&M storm costs. This issue is discussed in further detail below.

B. Company Proposal

Unitil proposes to continue its storm fund with certain modifications that were refined during the proceeding. As discussed in greater detail below, the proposed modifications are based on an adjustment for inflation, as well as the average number of storm-fund-eligible events increasing from two events per year to four events per year and the cost considerations and calculations associated with that increase. First, the Company seeks to increase the storm-fund-eligible event threshold from $25,000 in incremental O&M expenses to $29,000 to account for inflationary increases (Exhs. DPU 26-1 & Att. (electric); Unitil-WPs 6, 6.2 (Rev. 4) (electric)). Second, the Company proposes to modify the annual contribution to the storm fund collected through base distribution rates from $140,000 to $267,000 to account for an increase in the average number of storm-fund-eligible events and their costs over the past five years (Exhs. DPU 44-1 & Att. (electric); Unitil-WP 6 (Rev. 4) (electric)). Finally, the Company seeks to increase the annual recovery of incremental O&M expenses collected in base distribution rates from $50,000 to $116,000, also to reflect the increase in the average number of storm-fund-eligible events per year since the inception of the storm fund (Exhs. DPU 26-1 & Att. (electric); Unitil-WP 6 (Rev. 4) (electric)). The Company does not seek to modify the remaining components of the storm fund. Thus, the Company would retain the $350,000 per storm-fund-eligible event cap and the ability to defer recovery of exogenous storm costs, the carrying charges component in the storm fund would not change, and the Company would maintain the SRAC.

C. Positions of the Parties

The Company submits that storm-fund-eligible events are becoming more common and more costly, as weather patterns and meteorological characteristics associated with climate change are resulting in more powerful and destructive storms (Company Brief at 235-236 (electric), citing Exh. Unitil-CGDN-1, at 46 (electric); D.P.U. 22-22, at 272-273, 278-279). The Company argues that in addition to the frequency and magnitude of storm events, customer and political expectations are compelling shorter restoration durations, which drives up costs (Company Brief at 236 (electric), citing D.P.U. 22-22, at 272-273). Thus, according to Unitil, its storm fund, along with the VMP and SRP discussed in Section VIII. above, continues to be an important component in the Company's ability to prepare for and respond to storms (Company Brief at 236). In this regard, Unitil asserts that it aims to restore service in a safe, effective, and timely manner consistent with all relevant internal and external guidelines and requirements, including relevant statutes and regulations and the Company's emergency response plan and cost control measures (Company Brief at 235-236 (electric), citing Exhs. Unitil-CGDN-1, at 46-47 (electric); DPU 26-2 (electric); DPU 26-3 (electric); DPU 30-1 (electric); DPU 30-2 (electric); DPU 33-3 (electric); G.L. 164, § 85B(a); 220 CMR 19.00; Final Revised Emergency Response Plan Guidelines for Electric Companies, D.P.U. 14-72 (2015)).

Unitil contends that its storm fund, which is based on previously approved storm funds for National Grid (electric) and NSTAR Electric, has worked effectively to stabilize restoration costs, create rate stability, avoid overburdening customers, and return to customers any over-recovery of costs (Company Brief at 236 (electric), citing Exhs. Unitil-CGDN-1, at 47-48 (electric); Unitil-SMS-5 (electric); DPU 43-3 (electric); AG 1-60 (electric)). On brief, the

Company repeats its proposed modifications to the storm fund (Company Brief at 236-237 (electric)). No other party addressed these issues on brief.

D. Analysis and Findings

1. Introduction

The Department's primary objective for allowing a storm fund is to stabilize the recovery of storm restoration costs of major storms on ratepayers. D.P.U. 22-22, at 271; D.P.U. 18-150, at 413; D.P.U. 17-05, at 545; D.P.U. 15-155, at 73; D.P.U. 13-90, at 13; D.P.U. 10-70, at 201-202; D.P.U. 09-39, at 206. The Department has recognized that the use of storm funds may shift the burden of cost recovery disproportionately to ratepayers without providing commensurate benefits. D.P.U. 22-22, at 271; D.P.U. 18-150, at 413-414; D.P.U. 17-05, at 545; D.P.U. 15-155, at 73; D.P.U. 13-90, at 13. As such, the Department has put all EDCs on notice that if they seek continuation of a storm fund in their next base distribution rate case, they must demonstrate why the continuation of a storm fund is in the best interest of ratepayers. D.P.U. 22-22, at 271; D.P.U. 18-150, at 414; D.P.U. 17-05, at 545; D.P.U. 15-155, at 73-74; D.P.U. 13-90, at 14-15.

2. Continuation of the Storm Fund

The Department has devoted significant time and resources to policies designed to improve each EDC's storm response. As a result, storm response requirements are now more formalized, more comprehensive, and more rigorous. See, e.g., G.L. c. 164, § 1J; 220 CMR 19.03 (setting forth standards for acceptable performance for emergency preparation and restoration services for electric and gas companies); Investigation into Storm Response, D.P.U. 11-85-B/11-119-B at 141 (2012) (imposing penalties for company's failure to timely respond to emergency wires-down calls and communicate effectively with municipal officials and customers); Western Massachusetts Electric Company, D.P.U. 11-119-C at 71-72 (2012) (imposing penalties for company's failure to restore service to its customers in a safe and reasonably prompt manner). To meet these requirements, EDCs are expected to properly prepare for and implement storm response measures that restore power safely and expeditiously. These obligations require EDCs to devote substantial resources to achieving the desired results.

A storm fund provides a level of rate stability for customers, but only if it actually allows for recovery of storm costs over time without requiring a change to customer rates. D.P.U. 18-150, at 415-416; D.P.U. 15-155, at 78. Unitil's storm fund, which was implemented in November 2020, is relatively new when compared to decades old storm funds approved for National Grid (electric) and NSTAR Electric. Nevertheless, there has been significant major storm activity over the past few years, and the average of storm-fund-eligible events has increased from two per year to four per year, as detailed further below. Additionally, the Company experienced two major storm events in 2023 totaling approximately $4.8 million in restoration costs (Exh. Unitil-CGDN-1, at 49 (electric)). See also Fitchburg Gas and Electric Light Company, D.P.U. 23-136 (Phase I) at 3-4 (2023). The Department anticipates that climate change and weather patterns will contribute to frequent and destructive storms, while customer expectations for safe, reliable, and rapid restoration remain unchanged and demanding (Exh. Unitil-CGDN-1, at 46-47 (electric)). Given these considerations, and in light of the approval of a PBR plan with a five-year stay-out provision for Unitil's electric division (see Section III.D.5. above), the Department finds that the continuation of a properly structured storm fund is the most appropriate approach for providing a balance between adequate recovery of future storm restoration costs and rate stability for customers. As such, the Department allows the continuation of the Company's storm fund but with several modifications, as discussed below.[175]

3. Modifications to the Storm Fund

a. Storm-Fund-Eligible Event Threshold

Pursuant to the Settlement in D.P.U. 19-130, for any storm event for which Unitil incurs more than $25,000 in incremental O&M costs, the Company is permitted to access the storm fund for reimbursement of only that portion of storm costs that exceeds $25,000. D.P.U. 19-130, at 6 n.6. In the instant proceeding, the Company initially proposed a continuation of the current $25,000 storm-fund-eligible event threshold (Exhs. Unitil-CGDN-1, at 47-48 (electric); Unitil-WP 6 (electric)).

During the proceeding, the Company revised its proposed storm-fund-eligible event threshold from $25,000 to $29,000 (Exhs. DPU 26-1 & Att. (electric); Unitil-WPs 6, 6.2 (Rev. 4) (electric)). Unitil's revised threshold is based on the current storm-fund-eligible event threshold of $25,000, adjusted by the cumulative inflation change of the GDP-PI, as reported by the U.S. Bureau of Economic Analysis, from the third quarter of 2020 through the fourth quarter of 2023, rounded to the nearest thousand dollars (Exhs. DPU 26-1 (electric); Unitil-WPs 6, 6.2 (Rev. 4) (electric)). In deciding to continue established storm funds, the Department has found it appropriate to increase the storm-fund-eligible event threshold to account for the general increase in costs and to prevent the inclusion in the storm fund of future storms of a more routine nature.

175 The Company's PBR mechanism adjustments do not apply to the annual storm fund contribution or thresholds. (See Section III.D.5.h. above)

D.P.U. 15-155, at 76-77. See also D.P.U. 22-22, at 274; D.P.U. 18-150, at 417; D.P.U. 17-05, at 548. Here, the Department finds the Company's revised proposed storm fund-eligibility threshold of $29,000 is calculated in a manner that is reasonable and consistent with Department precedent.[176] D.P.U. 22-22, at 274; D.P.U. 18-150, at 417; D.P.U. 17-05, at 548; D.P.U. 15-155, at 76. For this reason, the Department approves a storm-fund-eligible event threshold of $29,000 per storm.

b. Annual Storm Fund Contribution Collected Through Base Distribution Rates

The Company initially proposed to increase the annual storm fund contribution collected through base distribution rates from $140,000 to $291,000 (Exhs. Unitil-CGDN-1, at 47 (electric); Unitil-WP 6 (electric)). The Company's initial proposal was based on average cost of 24 storm-fund-eligible events (less the $25,000 storm-fund-eligible threshold for each event) that occurred during the five-year period from January 2018 through December 2022 (Exh. Unitil-WP 6 (electric)).[177] During the proceeding, the Company revised the calculation using the increased storm-fund-eligible threshold of $29,000, which resulted in two storm events no longer qualifying for recovery in the storm fund (Exhs. DPU 26-1 & Att. (electric); DPU 44-1

176 The Department notes that we have not directed EDCs to employ a specific timeframe for adjusting the storm-fund-eligible event threshold by inflation based on GDP-PI from the U.S. Bureau of Economic Analysis.

177 The Company reported a total cost for the 24 storm-fund-eligible events to be $2,054,382 (Exh. Unitil-WP 6 (electric)). The Company removed $600,000 from the total to account for the $25,000 threshold for each event (i.e., $25,000 x 24 = $600,000) to yield a net total cost of $1,454,382 (Exh. Unitil-WP 6 (electric)). The net total cost of $1,454,382 divided by five years and rounded to the nearest thousand, yields an average annual cost of $291,000 (Exh. Unitil-WP 6 (electric)).

& Att. (electric); Unitil-WP 6 (Rev. 4) (electric)). As a result, the Company proposed a revised annual storm fund contribution collected through base distribution rates of $267,000 (Exhs. DPU 44-1 & Att. (electric); Unitil-WP 6 (Rev. 4) (electric)).[178]

The Department has reviewed the Company's proposals and supporting calculations (Exhs. DPU 26-1 & Att. (electric); DPU 44-1 & Att. (electric); Unitil-WPs 6, 6.2 (Rev. 4) (electric)). The Department finds the Company's proposed revised amount of annual storm fund contribution collected through base distribution rates of $267,000 is consistent with Department precedent. D.P.U. 22-22, at 276; D.P.U. 18-150, at 424-427; D.P.U. 17-05, at 531, 553. Therefore, the Department approves the Company's proposal to increase the annual storm fund contribution collected through base distribution rates from $140,000 to $267,000.

c. Annual O&M Expense for Storm Events

The Company initially proposed to increase the annual O&M expense associated with storm events from $50,000 to $125,000 (Exhs. Unitil-CGDN-1, at 47-48 (electric); Unitil-WP 6 (electric)). This proposal was based on the average annual number of storm-fund-eligible events from 2018 through 2022, which was five events,[179] multiplied by the storm-fund-eligible

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[178] The Company reported a total cost for the remaining 22 storm-fund-eligible events to be $1,973,951 (Exhs. DPU 44-1, Att. 1 (electric); Unitil-WP 6 (Rev. 4) (electric)). The Company removed $638,000 from the total to account for the revised $29,000 storm-fund-eligible event threshold for each event (i.e., $29,000 x 22 = $638,000) to yield a net total cost of $1,335,951 (Exhs. DPU 44-1, Att. 1 (electric); Unitil-WP 6 (Rev. 4) (electric)). The net total cost of $1,335,951 divided by five years and rounded to the nearest thousand, yields an average annual cost of $267,000 (Exh. Unitil-WP 6 (electric)).

[179] As noted above, the Company initially reported 24 storm-fund-eligible events over a five-year period; thus, 24 divided by five years and rounded to the nearest whole number

threshold of $25,000 (Exh. Unitil-CGDN-1, at 47-48 (electric)). During the proceeding, the Company revised its proposed annual O&M expense associated with storm events from $125,000 to $116,000 (Exhs. DPU 26-1 & Att. (electric); Unitil-WP 6 (Rev. 4) (electric)). The revised amount is based on the revised storm-fund-eligible threshold of $29,000 and, as noted above, the removal of two storm-fund-eligible events from the total number of such events that occurred from 2018 through 2022, which reduced the average number of storm-fund-eligible events over the five-year span from five to four events[180] (Exhs. DPU 26-1 (electric); Unitil-WP 6 (Rev. 4) (electric)).

As the frequency of storm-fund-eligible events has increased since the Department approved Unitil's storm fund, the test-year level of O&M costs in base distribution rates of $50,000 based on an average of two storm-fund-eligible events per year is not necessarily representative of the Company's future costs. D.P.U. 22-22, at 277; D.P.U. 17-05, at 550. Therefore, consistent with Department precedent, we find it necessary to normalize the level of base distribution rate recovery to derive a more representative threshold amount for O&M expenses associated with storm events. D.P.U. 18-150, at 418-419; D.P.U. 17-05, at 550; D.P.U. 15-155, at 80-81. In this instance, the Department finds that the Company's proposal to

equals an average of five storm-fund-eligible events per year (Exh. Unitil-WP 6 (electric)).

180 22 storm-fund-eligible events divided by five years and rounded to the nearest whole number equals an average of four storm-fund-eligible events per year (Exhs. DPU 26-1 (electric); Unitil-WP 6 (Rev. 4) (electric)). Thus, multiplying the four storm-fund-eligible events by $29,000 yields the revised proposed annual O&M expense associated with storm events of $116,000 (Exhs. DPU 26-1 & Att. (electric); DPU 44-1 & Att. (electric); Unitil-WP 6 (Rev. 4) (electric)).

recover annual O&M expense of $116,000 in base distribution rates, based upon recovery for four storm-fund eligible-events per year and applying the approved $29,000 storm fund eligibility threshold, is reasonable and consistent with Department precedent. D.P.U. 22-22, at 277; D.P.U. 18-150, at 418-419; D.P.U. 17-05, at 550; D.P.U. 15-155, at 80-81. Accordingly, we approve the Company's proposal for $116,000 of annual O&M expense associated with storms-fund-eligible events to be collected in base distribution rates.

d. Storm Fund Symmetrical Cap

As noted above, in the Settlement approved in D.P.U. 19-130, the Company was allowed a storm fund, effective November 1, 2020, with the same elements as the storm funds approved by the Department for National Grid (electric operations) and NSTAR Electric. D.P.U. 19-130, at 6, citing Settlement at §§ 1.2.6.1 through 1.2.6.3. During the instant proceeding, Unitil acknowledged that a storm fund symmetrical cap like those implemented for National Grid (electric) and NSTAR Electric was not established as part of the Settlement (Tr. 2, at 125-127). The Company contended that the magnitude of its storm fund is vastly different compared to National Grid (electric)'s and NSTAR Electric's storm funds (Tr. 2, at 126-127). The Company also stated that it is important to minimize storm expense carrying charges and rate changes experienced by ratepayers (Tr. 2, at 127-128). As such, the Company asserted that submitting an annual SRAC filing reduces carrying costs, benefits ratepayers, and eliminates the need for a symmetrical cap (Tr. 2, at 127-128).

The Department approved a symmetrical cap for National Grid (electric) in D.P.U. 09-39, at 208, that was subsequently modified in D.P.U. 15-155, at 82, and approved a symmetrical cap for NSTAR Electric in D.P.U. 17-05, at 554, that was continued in D.P.U. 22-22, at 283. The

Department found that a symmetrical cap on the storm fund balance was appropriate to minimize the potential for frequent rate changes (either positive or negative), and to realign the risks associated with storm cost recovery to protect ratepayers' interest. D.P.U. 17-05, at 554; D.P.U. 15-155, at 82. While we expect the frequency and magnitude of storms to increase over time, there remains a degree of uncertainty regarding the fluctuation of storm costs from year to year. D.P.U. 22-22, at 275.

Additionally, the Department finds that the Company may file for recovery of storm costs in excess of the symmetrical cap through the SRAC when the storm fund deficit balance is greater than $350,000. Consistent with the Company's current SRAC, the filing shall be made at least 45 days before January 1st of the next year. M.D.P.U. No. 421A, § 5.0 (electric). Similarly, when the storm fund balance is in a surplus of over $350,000, the Company shall submit a filing to return the overage to customers through the SRAF in the SRAC tariff. Consistent with the Company's current SRAC, the filing shall be made at least 45 days before January 1st of the next year. If the storm fund balance is in a deficit greater than the symmetrical cap, and the Company elects not to file for recovery of storm costs in excess of the symmetrical cap, the Company must provide in its next annual electric reconciliation filing a rationale for such decision.

The Company must continue to seek Department approval for cost recovery through the storm fund. Further, the Company shall continue to file cost documentation related to storm-fund-eligible storms for the previous year (i.e., storm-fund-eligible storms that occurred during the prior calendar year shall be filed annually with the Department)[181] for the Department

[181] The Company shall still file with the Department supporting documentation related to storm-fund-eligible events it that seeks to include in the storm fund.

to conduct prudency reviews for storm-fund-eligible storms. Such a filing should include complete and final invoice and cost documentation and supporting testimony. To the extent that Unitil is unable to prepare a final accounting of storm costs, along with relevant supporting testimony and complete and full documentation to facilitate a full administrative review, Unitil is directed to file, in that filing, a supplemental filing for storm costs as soon as such information is complete. Any costs that the Department finds imprudent or inconsistent with Department storm cost recovery precedent shall be excluded from recovery through the storm fund. The Company is directed in its compliance filing to file a new SRAC tariff, consistent with the changes directed in this Order.

4. Exogenous Storm Costs

As noted above, the Settlement allows for the Company to defer recovery of exogenous storm costs and to seek recovery of those costs through a separate filing or as part its next base distribution rate case. D.P.U. 19-130, at 6 & n.6, citing Settlement at §§ 1.2.6.4 through 1.2.6.7. In D.P.U. 23-136, Unitil sought to revise the SRAC tariff to provide for the recovery of exogenous storm events through that tariff, as opposed to the alternatives set forth in the Settlement. D.P.U. 23-136 (Phase I) at 3-5. The Department approved the Company's proposal to commence recovery on January 1, 2024, of the storm costs associated with the two exogenous storm events, subject to further investigation and reconciliation. D.P.U. 23-136 (Phase I) at 8. In reaching this decision, the Department found that because a final expense amount had not been determined, recovery of these costs in the instant base distribution rate case would be inappropriate. D.P.U. 23-136 (Phase I) at 7. Further, the Department concluded that, if in the instant case we approved Unitil's proposed PBR plan with a five-year stay out provision, the

Settlement provision allowing Unitil to defer recovery of these costs to the Company's next base distribution rate case would be untimely and unreasonable given the accrual of additional carrying costs in the interim. D.P.U. 23-136 (Phase I) at 7. Moreover, the Department found that because Unitil's annual SRAF filing includes reconciliation of expenses and revenues for prior periods, any storm costs ultimately deemed unreasonable or imprudent can be reconciled and returned to ratepayers in the Company's next annual SRAF filing. D.P.U. 23-136 (Phase I) at 7-8.

The Company did not raise the issue of recovery of exogenous storm events through the SRAC in the instant proceeding; however, we find it appropriate to address the issue here. Based on our findings in D.P.U. 23-136 (Phase I) at 7-8 as outlined above, and in light of the decision today to approve a five-year PBR plan with a stay out provision for the Company's electric division, we determine that it is reasonable to allow for the recovery of future exogenous storms through the SRAC, subject to investigation, prudency review, and reconciliation. We also find that the recovery of the exogenous storm costs through the SRAC in this manner provides for administrative efficiency and is consistent with Department precedent. See D.P.U. 22-22, at 282-283. Accordingly, the Department directs the Company in its compliance filing to revise its SRAC tariff consistent with this finding.[182]

[182] This finding does not prejudge the exogenous storm costs at issue in phase two of D.P.U. 23-136. The Department will make separate findings regarding recovery of those costs in that proceeding.

5. Interim Storm Fund Reporting

To facilitate the Department's expedited and efficient review of Unitil's storm-cost filings, including an evaluation of the prudency of such costs, the Department establishes the following storm reporting requirements. Consistent with the Department's directives in D.P.U. 17-05 and D.P.U. 15-155-A, Unitil must submit to the Department, no later than six months after the occurrence of a storm fund qualifying event, a preliminary report providing: (1) a detailed explanation of the storm event; (2) a detailed summary of the costs itemized by cost category; (3) the amount of carrying charges incurred to date; and (4) a detailed summary of anticipated additional costs to be incurred or finalized, including an estimated timeframe for the receipt of outstanding cost information or final cost accounting. D.P.U. 17-05, at 562; D.P.U. 15-155-A at 16-17.[183] Unitil thereafter must provide a quarterly update on the status of finalizing the accounting of storm costs.

E. Conclusion

The Department finds that continuation of the Company's storm fund is appropriate with certain modifications. The parameters of the Company's storm fund shall be the following: (1) a per storm storm-fund-eligible event threshold of $29,000; (2) an annual base distribution rate contribution to the storm-fund of $267,000; (3) recovery through the cost of service of $116,000 in O&M expenses to account for an average of four storm-fund-eligible events per year; (4) recovery through the storm-fund of incremental O&M expenses associated with

183 This filing requirement does not relieve Unitil of its obligation to make necessary storm-related filings consistent with other Department directives (e.g., reports concerning emergency preparedness and restoration of service under 220 CMR 19.03(4)).

storm-fund-eligible events where total individual incremental O&M expenses are above the $29,000 storm-fund-eligible event threshold and below $350,000; (5) accrual of carrying charges to the storm fund monthly balance at the prime rate, beginning at the time of cost incurrence as a result of receipt of invoices for such charges; (6) deferral of exogenous storm costs, with carrying charges accrued at the prime rate, beginning at the time of cost incurrence as a result of receipt of invoices for such charges, with the recovery of the exogenous storm costs through the SRAC, subject to a prudency review; and (7) a symmetrical cap of $350,000 to be applied to the storm fund, such that when the storm fund is in a deficit position over the cap, amounts in excess of the cap may be recovered through the Company's SRAF in the SRAC tariff, and when the storm fund is in a surplus position over the cap, amounts in excess of the cap shall be returned to customers through a credit in the Company's SRAF. The Department also reaffirms its finding that the Company must continue to seek Department approval to include storm events for cost recovery through the storm fund and directs the Company to include supporting documentation in such filings.

X. ADVANCED METERING INFRASTRUCTURE PROPOSAL

A. Introduction

Unlike the other EDCs in the Commonwealth, Unitil already deployed AMI meters ("TS2 meters"), beginning in 2006. D.P.U. 07-71, at 11-15, 36. In Second Grid Modernization, at 54, the Company reported that approximately one-half of its existing TS2 meters would be reaching the end of their useful life in the next few years, and the meters were no longer produced or supported by their manufacturers, as they had been outpaced by new technology that can provide more granular and timely usage information. As a result, the Company began replacing its existing meters with new PLX meters[184] at a business-as-usual pace. Second Grid Modernization at 54. The Department approved accelerated replacement of the Company's TS2 meters with newer, more capable PLX meters during the 2022-2025 Grid Modernization Plan term. Second Grid Modernization at 203-205. Costs associated with the Company's existing meters are currently recovered through base distribution rates (Exh. Sch. RevReq-4-1, at 2 (Rev. 4) (electric)). Costs associated with new PLX meters approved for accelerated deployment were to be recovered through the Company's GMF. Second Grid Modernization at 263-264, 283.[185]

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[184] According to Unitil, PLX meters can provide interval metering functionality beyond that of its existing meters, thus allowing the Company to accommodate time-varying rate structures; provide more frequent and timelier meter read information to customers and the Company; and support 15-minute load profile information. Second Grid Modernization at 53.

[185] The Company's current GMF tariff (M.D.P.U. No. 428 (electric)) was approved in Fitchburg Gas and Electric Light Company, D.P.U. 24-54 (Phase I) at 7, 10 (May 31, 2024). In that proceeding, the Company also submitted a request for approval of a change in scope to its AMI meter replacement investments preauthorized for the 2022-2025 Grid Modernization Plan. In particular, Unitil proposed that due to the anticipated discontinuance and obsolescence of the preauthorized PLX metering technology that relies on the Company's existing power line carrier communication system, the Company would replace all existing meters, both TS2 and PLX meters, with new wireless meters that rely on a radio frequency mesh network and a cellular communication network. D.P.U. 24-54, Exh. KSJG-1, at 6, 7. To support the new wireless meters, the Company also proposed to deploy the corresponding communications network equipment and head-end system. D.P.U. 24-54, Exhibit KSJG-1, at 6, 11-12. The Department's review and decision on the Company's request for preauthorization of the revised scope of its AMI plan during the 2022-2025 Grid Modernization Plan term, and proposal to recover the purchase and installation costs for the new wireless meters, the head-end system replacement costs, and the installation, testing, and commissioning costs of the new communications network through its GMF, will occur in phase two of the AMI portion of the proceeding in D.P.U. 24-54.

During the instant proceeding, the Department inquired about the feasibility, as well the potential benefits and consequences, of transferring the recovery of the revenue requirement associated with its existing meters (including depreciation expense, pre-tax rate of return, property tax expense, ADIT, and applicable taxes) to the GMF rather than through base distribution rates (Exh. DPU 43-1, at 1 (electric)). In response, the Company stated that, if directed to recover the revenue requirement associated with existing meters through a separate mechanism, the Company would propose to recover these costs through a stand-alone Advanced Meter Infrastructure Factor ("AMIF") consistent with the AMI tariff approved in D.P.U. 22-22, for transparency and ease of review purposes (Exh. DPU 43-1, at 1 (electric)).[186] The Company reasoned that use of a separate AMIF would allow for the separation of AMI costs from other grid modernization costs being recovered through the GMF, thus allowing for a more efficient and effective review of costs consistent with Department directives (Exh. DPU 43-1, at 1 (electric)). In any event, the Company conceded that if all current and future meter-related capital costs were recovered through either the GMF or newly established AMIF starting on July 1, 2024, the Department would have a clear line of sight into the amount of recovery that the Company is receiving for its metering infrastructure, thus eliminating the risk of any potential over-recovery of meter-related capital costs (Exh. DPU 43-1 (electric)).

The Company stated that it could implement a new reconciling factor, whether through the GMF or a new AMIF, effective July 1, 2024, for the purpose of commencing recovery of the

[186] National Grid (electric) proposes a similar AMIF tariff and transfer of legacy meters and communications costs to a separate, AMI reconciling mechanism in the companies' pending rate case. D.P.U. 23-150, Exhs. NG-RRP-1, at 106-108; NG-PP-1, at 46.

existing meter-related capital investment that would have otherwise been included in base distribution rates (i.e., as of December 31, 2023) on that date (Exh. DPU 43-1, at 1-2 (electric)). The Company stated that the GMF (or AMIF) would be reset to annually establish the then-current year's revenue requirement for: (1) the costs associated with meters that were extracted from rate base; and (2) eligible AMI investments placed into service during the prior investment year (Exh. DPU 43-1, at 2 (electric)).[187]

The Company provided an illustrative AMIF tariff (Exh. Unitil-3 (2/1/24) (electric)). The proposed tariff provides for the recovery of costs associated with the Company's implementation and deployment of AMI as approved by the Department from time to time for investments made between 2022 and 2025, as well as for costs associated with the Company's legacy AMI meters and related infrastructure, including station equipment, communications equipment, and other related infrastructure, including cost of removal (Exh. Unitil-3, at 2 (2/1/24) (electric)). Eligible costs would include the pre-tax return on rate base on eligible investment, along with associated depreciation expense, property taxes, and allowable O&M expense as defined by the proposed tariff (Exh. Unitil-3, at 2-4 (2/1/24) (electric)). The annual filing would also reconcile the actual revenue collections and expenditures occurring in the year prior to the rate year, with carrying costs on the average monthly reconciliation balance equal to

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187 The Company reasoned that because the Department typically does not allow cost recovery to commence through a rate mechanism until the investments are "used and useful" or in-service to customers, it would begin to recover the cost of metering investment beginning in the year after the plant was placed in service (Exh. DPU 43-1, at 2 (electric)).

the interest rate paid on customer deposits pursuant to 220 CMR 26.09 (Exh. Unitil-3, at 2, 5 (2/1/24) (electric)).[188]

The Company noted that recovering all meter investments through either the GMF or AMIF would require the removal of all applicable meter-related investments, including plant, accumulated depreciation and amortization, and ADIT, from base distribution rates (Exh. DPU 43-2 (electric)). Additionally, the Company would need to remove associated O&M expense, property tax expense, depreciation and amortization expense from the Company's proposed revenue requirement and make further adjustments for any associated offsets that are determined during the Department's review of the Company's proposal (Exh. DPU 43-2 (electric)).

Based on the Company's meter investment as of December 31, 2023, the Company determined that recovering all meter-related costs outside of base rates would result in a reduction of $1,701,982 in base distribution rates (see Exhs. Unitil-CGDN-10, at 1 (Rev. 4) (AMI Included) (electric); Unitil-CGDN-10, at 1 (Rev. 4) (AMI Excluded) (electric)). The Company determined this reduction by first multiplying $11,054,648 in plant in service booked to Accounts 362, 370, and 397, less $4,981,087 in accumulated depreciation, $695,938 in ADIT, and $13,630 assigned to internal transmission, by the Company's proposed pre-tax rate of return of 10.09 percent (Exhs. Unitil-2, at 2-3, 7 (2/1/24) (electric); Sch. RevReq-4-1, at 2 (Rev. 4)

188 The current customer deposit interest rate is 4.58 percent. https://www.mass.gov/info-details/interest-rates-for-security-deposits-for-investor-owned-utilities (accessed May 4, 2024).

(electric); Sch. RevReq-4-2, at 2 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (electric)).[189] This calculation produced a pre-tax return requirement of $542,616 (see Exhs. Unitil-2, at 1 (2/1/24) (electric); Sch. RevReq-4-1, at 2 (Rev. 4) (electric); Sch. RevReq-4-2, at 2 (Rev. 4) (electric); Sch. RevReq-4-6 (Rev. 4) (electric)). The Company then calculated a required reduction of $966,597 in depreciation expense assigned to base distribution rates (see Exhs. Sch. RevReq-3-18, at 3 (Rev. 4) (AMI Included) (electric); Sch. RevReq-3-18, at 4 (Rev. 4) (AMI Excluded) (electric)).[190] In addition, the Company calculated a required reduction of $13,533 in O&M expense associated with a software agreement for the Company's legacy meters, and a reduction of $116,591 in property taxes (Exhs. Unitil-2, at 5-6 (2/1/24) (electric); Sch. RevReq-3-11 (Rev. 4) (electric); Sch. RevReq-3-22 (Rev. 4) (electric)). The remaining difference is primarily attributable to corresponding changes in distribution-related bad debt (see Exhs. Unitil-CGDN-10, at 2 (Rev. 4) (AMI Included) (electric); Unitil-CGDN-10, at 2 (Rev. 4) (AMI Excluded) (electric)).[191]

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[189] A portion of the Company's plant booked to Account 397, Communications Equipment, is assigned to internal transmission. Based on the Company's proposed plant and accumulated depreciation internal transmission allocator of 5.1021 percent, $13,630 of plant in service and $11,227 in accumulated depreciation is assigned to internal transmission (see Exhs. Sch. RevReq-4-1, at 2 (Rev. 4) (electric); Sch. RevReq-4-2, at 2 (Rev. 4) (electric)).

[190] A portion of the Company's plant booked to Account 397, Communications Equipment, is assigned to internal transmission. Based on the Company's proposed internal transmission allocator of 5.1021 percent, $909 in meter-related depreciation expense is assigned to internal transmission (Exh. Sch. RevReq-3-18, at 3 (Rev. 4) (electric)).

[191] The remaining difference is attributable to corresponding changes in distribution-related bad debt.

The Company essentially repeated its response to Exhibit DPU 43-1 (electric) on brief (Company Brief at 256-259, citing Exh. DPU 43-1 (electric)). No intervenor raised the issue of AMI cost recovery on brief.

B. Analysis and Findings

During the proceeding, the Department explored the potential for under- or over-recovery of metering and related costs from AMI implementation, as well as the Company's willingness to recover all meter costs, i.e., meter-related capital, through the GMF beginning on July 1, 2024 (Exhs. DPU 43-1 (electric); DPU 43-2 (electric)). The Company did not object to recovering all meter-related capital through the AMIF or the GMF and noted that such treatment would eliminate the potential for over-recovery of costs, the need to establish any regulatory assets for unrecovered legacy meter costs, and the need to recognize any offsets in the reconciling mechanism to coordinate between amounts still being recovered in base distribution rates (Exh. DPU 43-1 (electric)).

The Department gives careful consideration to the formation of any new cost reconciling mechanisms. See, e.g., D.P.U. 10-55, at 66 n.43; D.T.E. 05-27, at 183-186; D.T.E. 03-47-A at 25-28, 36-37; Eastern Enterprises/Essex County Gas Company, D.T.E. 98-27, at 6, 28 (1998). Such consideration is warranted because certain cost recovery mechanisms can lessen the incentive of a utility to control its costs. Under conventional ratemaking practice, there is a time gap between when a utility incurs a cost and when the utility recovers its costs through new rates. This time gap is referred to as "regulatory lag" and it provides a strong incentive for companies to control costs and to invest wisely in capital. D.P.U. 09-39, at 80. Cost reconciling mechanisms, because they allow for dollar-for-dollar recovery from ratepayers, substantially reduce, or in some cases eliminate, benefits to ratepayers previously attained through regulatory lag. The Department has never defined or quantified a specific level of volatility needed for costs to be recovered through a reconciling mechanism, and the Department is not required to justify different ratemaking treatment for various costs incurred by a company. Rather, the Department addresses these issues on a fact-specific, case-by-case basis. See, e.g. D.P.U. 13-90-A at 10; D.T.E. 03-47-A at 16; D.P.U. 96-50 (Phase I) at 81.

Under the current ratemaking framework, costs associated with new AMI meters would be recovered on an accelerated basis through the reconciling GMF, while costs associated with the test-year-end number of existing AMI meters would be recovered through base distribution rates (Exh. Sch. RevReq-4-1, at 2 (Rev. 4) (electric)). Consequently, as the number of existing meters in service decreases through their replacement with new meters, there is a risk of double-recovery because while all new meter-related costs are being recovered through the GMF, the Company's base rates would still include costs associated with the test-year-end number of meters, including those that have already been replaced with new meters (Exh. DPU 43-1, at 1 (electric)). To eliminate this risk of double-recovery, the Department finds it appropriate to remove all of the Company's meter-related costs from base distribution rates and instead recover these costs through a reconciling mechanism.

While the Department approves the recovery of all meter-related costs through a reconciling mechanism, a separate AMIF is not necessary to ensure against double-recovery of meter-related costs. Based on Unitil's proposal filed in D.P.U. 24-54, the Company expects that installation of the replacement meters, communication technology and head-end system will continue on the same timeline and approximate cost previously proposed for the new PLX meter implementation and reviewed in Second Grid Modernization. Fitchburg Gas and Electric Light Company, D.P.U. 24-54, Exh. KSJG-1, at 6, 10. The existence or nonexistence of the AMIF will affect neither the strategy pursued by Unitil in the achievement of its public service obligations nor the pace with which the Company expects to make grid modernization investments. Furthermore, the Department is not persuaded that the apparent transparency of meter-related costs reviewed through an AMIF produces any clear advantages over reviewing metering costs as part of the Company's GMF. Nevertheless, the Department is persuaded that transferring Unitil's meter-related costs from base distribution rates to the GMF will facilitate review of the Company's AMI Implementation Plan. Additionally, although the Department does not approve a separate AMIF for the recovery of the Company's meter-related costs, we find that recovery of legacy metering infrastructure costs through the GMF is consistent with the approach approved by the Department for NSTAR Electric, as recovery through an annual reconciling mechanism will minimize the potential for over-recovery of costs as legacy infrastructure is being replaced at an accelerated schedule. See D.P.U. 22-22, at 186, 351, 353; Second Grid Modernization at 299-300.

Based on these considerations, as well as the administrative efficiency of reviewing and recovering related costs through a single mechanism, the Department directs the Company to remove all meter-related costs from base distribution rates, and to instead recover them through the GMF. The Department accepts the Company's proposed reduction to plant in service associated with Accounts 362, 370, and 397 in the amount of $11,054,648, as well as the associated accumulated depreciation of $4,981,087 and ADIT in the amount of $695,938 (Exhs. Sch. RevReq-4-1, at 2 (Rev. 4) (electric); Sch. RevReq-4-2, at 2 (Rev. 4) (electric);

Sch. RevReq-4-6, at 2 (Rev. 4) (electric)).[192] The Department also accepts the Company's proposed reductions in depreciation expense in the amount of $966,597,[193] O&M expense in the amount of $13,533 associated with legacy metering software licensing, and property tax expense of $116,591 (Exhs. Unitil-2, at 5-6 (2/1/24) (electric); Sch. RevReq-3-11 (Rev. 4) (electric); Sch. RevReq-3-22 (Rev. 4) (electric)).[194] The Company shall file a revised GMF for effect July 1, 2024, as part of the compliance filing to this Order.

Finally, during the test year, Unitil booked $445,038 in metering and miscellaneous customer account expenses to its electric division[195] (Exh. AG 1-2, Att. 6(4), at 115 (electric)). This amount represents the baseline amount of meter-related expenses the Company will have to compare its actual meter-related expenses against to determine the level of incremental AMI-meter related O&M expense to be recovered through the GMF. D.P.U. 22-22, at 352. The Department directs the Company to track and document meter-related O&M costs required for AMI implementation and to recover as incremental costs the lesser of these costs or the net change to Accounts 586, 597 and 902 from the test-year amount of $445,038, adjusted each year

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[192] Of these amounts, $13,630 of plant in service assigned to internal transmission had been removed, and $11,227 in accumulated depreciation is assigned to internal transmission.

[193] Of this amount, $909 is assigned to internal transmission.

[194] The Company identified $1,701,982 as the annual recovery amount based on its proposed ROE (Exhs. Unitil-CGDN-10, at 1 (Rev. 4 AMI Included); Unitil-CGDN-10, at 1 (Rev. 4 AMI Excluded)). This amount will be revised using the ROE approved by the Department in this Order.

[195] This total consists of $381,057 booked to Account 586 (Meter Expenses – Operations), $12,129 booked to Account 597 (Meter Expenses – Maintenance), and $51,852 booked to Account 902 (Meter Reading Expenses).

for the annual change in rates as determined by the Company's PBR mechanism. D.P.U. 22-22, at 352.

XI. CAPITAL STRUCTURE AND COST OF CAPITAL

A. Overview

Unitil proposes an 8.04 percent WACC for its electric division and an 8.17 percent WACC for its gas division, each of which represents the rate of return applied to each division's rate base, to determine the Company's total return on its investment (Exhs. Unitil-CGDN-10, at 4, 5 (Rev. 4) (electric); Sch. RevReq-5 (Rev. 4) (electric); Unitil-CGDN-7, at 4, 5 (Rev. 4) (gas); Sch. RevReq-5 (Rev. 4) (gas)). The Company calculates each division's WACC based on the following components: (1) a proposed capital structure of 47.74 percent long-term debt and 52.26 percent common equity for both divisions; (2) a cost of long-term debt of 5.34 percent for both divisions; (3) a proposed ROE[196] of 10.50 percent for the electric division; and (4) a proposed ROE of 10.75 percent for the gas division (Exhs. Unitil-DWD-1, at 3 (electric); Unitil-TDAF-1, at 4 (electric); Sch. RevReq-5 (Rev. 4) (electric); DPU 34-1 & Att. (electric); Unitil-DWD-1, at 3 (gas); Unitil-TDAF-1, at 4 (gas); Sch. RevReq-5 (Rev. 4) (gas); DPU 29-1 & Att. (gas)).

The Attorney General recommends that the Department determine each division's WACC based on the following components: (1) an imputed capital structure consisting of 50 percent long-term debt and 50 percent common equity for both divisions; (2) a long-term debt

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196 The Department interchangeably uses the terms ROE and cost of equity throughout this section.

cost rate of 5.34 percent for both divisions;[197] (3) an ROE of 8.85 percent for the electric division; and (4) an ROE of 8.45 percent for the gas division (Exhs. AG-JRW-1, at 5-6, 119; AG-JRW-Surrebuttal-1, at 8; Attorney General Brief at 61-62).[198] The Attorney General's recommendations would result in a 7.10 percent WACC for the electric division and a 6.90 percent WACC for the gas division.[199]

B. Capital Structure

1. Company Proposal

At the end of the test year, Unitil reported a capital structure consisting of $91,900,900 in long-term debt and $118,155,615 in common equity (Exhs. Sch. RevReq-5 (Rev. 4) (electric); Sch. RevReq-5 (Rev. 4) (gas)). The Company proposes two adjustments to its test-year-end capital structure (Exhs. Unitil-TDAF-1, at 6 (electric); Sch. RevReq-5 (Rev. 4) (electric); Unitil-TDAF-1, at 6 (gas); Sch. RevReq-5 (Rev. 4) (gas)). First, Unitil increases its long-term

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197 During this proceeding, Unitil revised its cost of long-term debt from 5.33 percent to 5.34 percent (Exhs. Sch. RevReq-5 (Rev. 4) (electric); DPU 34-1 & Att. (electric); Sch. RevReq-5 (Rev. 4) (gas); DPU 29-1 & Att. (gas)). The Attorney General accepted the Company's initially proposed cost of long-term debt before the Company submitted the revision, and the Attorney General did not comment on the revised cost of long-term debt (Exhs. AG-JRW-1, at 4; AG-JRW-Surrebuttal-1, at 7). The Department accepts Unitil's revised cost of long-term debt of 5.34 percent, as shown on the division-specific Schedule 5 below.

198 In testimony, the Attorney General proposed ROEs of 9.375 percent and 9.25 percent for the electric division and the gas division, respectively (Exh. AG-JRW-Surrebuttal-1, at 8). On brief, the Attorney General proposed ROEs of 8.85 percent and 8.45 percent for the electric division and the gas division, respectively (Attorney General Brief at 61-62). In our analysis, the Department relies on the ROEs proposed by the Attorney General on brief.

199 (8.85 x 0.5) + (5.34 x 0.5) = 7.10 and (8.45 x 0.5) + (5.34 x 0.5) = 6.90

debt by $20,600,000 to account for the Company's post-test-year long-term debt issuances totaling $25,000,000, less sinking fund redemption payments totaling $4,400,000 (Exhs. Unitil-CGDN-1, at 69-70 (electric); Sch. RevReq-5 (Rev. 4) (electric); Unitil-CGDN-1, at 56-57 (gas); Sch. RevReq-5 (Rev. 4) (gas)). Second, the Company includes a post-test-year capital contribution from Unitil of $5,000,000 in its common equity balance (Exhs. Unitil-CGDN-1, at 69 (electric); Unitil-TDAF-1, at 6 (electric); Sch. RevReq-5 (Rev. 4) (electric); Unitil-CGDN-1, at 56 (gas); Unitil-TDAF-1, at 6 (gas); Sch. RevReq-5 (Rev. 4) (gas)). Based on these adjustments, Unitil proposes a pro forma long-term debt balance of $112,500,000 and a pro forma common equity balance of $123,155,615, representing 47.74 percent long-term debt and 52.26 percent common equity (Exhs. Sch. RevReq-5 (Rev. 4) (electric); Sch. RevReq-5 (Rev. 4) (gas)).

2. Attorney General Proposal

The Attorney General states that Unitil's proposed capital structure includes more equity capital and, therefore, less financial risk than Unitil Corporation and the proxy groups used to determine Unitil's ROE in this proceeding (Exhs. AG-JRW-1, at 7, 30, 33-34, 119-120; AG-JRW-Surrebuttal-1, at 2, 7, 10). She explains that when a regulated utility's actual capital structure contains a high equity ratio the Department should: (1) impute a more reasonable capital structure; or (2) recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a lower ROE than the ROE for the proxy groups (Exh. AG-JRW-1, at 33). Accordingly, the Attorney General recommends that the Department should impute a capital structure of 50 percent long-term debt and 50 percent common equity or, if the Department approves Unitil's proposed capital structure, should authorize a lower ROE (Exh. AG-JRW-1, at 33).

3. Positions of the Parties

a. Attorney General

The Attorney General repeats her proposals on brief and argues that the Department should reject Unitil's proposed capital structure because it includes an inflated common equity ratio (Attorney General Brief at 21, 62, citing Exh. AG-JRW-1, at 7; Attorney General Reply Brief at 13). The Attorney General contends that Unitil's common equity ratio is higher than the equity ratios of the proxy groups and Unitil Corporation and, therefore, the Department should approve her consultant's proposal to impute a capital structure of 50 percent long-term debt and 50 percent common equity (Attorney General Brief at 21, 24-25, citing Exh. AG-JRW-1, at 7, 29-34).

b. Company

Unitil argues that its proposed capital structure is in accordance with Department precedent (Company Brief at 322 (electric); Company Brief at 255 (gas)). The Company also asserts that its proposed capital structure is consistent with the capital structure approved in the Company's most recent base distribution rate case as well as the capital structures recently approved for National Grid (electric), NSTAR Electric, NSTAR Gas Company, Eversource Gas Company of Massachusetts, and Boston Gas (Company Brief at 323-324 (electric); Company Brief at 256-257 (gas)). Further, Unitil contends that its proposed capital structure is within the range of the operating companies' capital structures included in the Company's proxy groups (Company Brief at 324 (electric); Company Brief at 257 (gas)). Accordingly, Unitil contends that the similarity between its proposed capital structures and (1) the capital structures of the Massachusetts utility companies as well as (2) the operating companies in the proxy groups, demonstrates that the Company's capital structure is consistent with sound utility practice and should be approved (Company Brief at 324, 335-336 (electric); Company Brief at 257, 269-270 (gas)).

4. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 22-22, at 356; D.T.E. 03-40, at 319; D.T.E. 01-56, at 97; Pinehills Water Company, D.T.E. 01-42, at 17-18 (2001). The ratio of each capital structure component to the total capital structure is used to weight the cost (or return) of each capital structure component to derive a WACC. D.P.U. 22-22, at 356; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5. The WACC is used to calculate the rate of return, which is applied to a company's rate base as part of the revenue requirement established by the Department, and it is made up of three components: (1) the cost of a company's long-term debt; (2) the cost of a company's preferred stock; and (3) the cost of a company's common equity or its allowed ROE set by the Department. D.P.U. 22-22, at 356-357; D.T.E. 03-40, at 319; D.T.E. 01-42, at 18; D.P.U. 86-149, at 5.

The Department typically will accept a company's test-year-end capital structure, allowing for known and measurable changes. D.P.U. 22-22, at 357; D.T.E. 03-40, at 323-324; D.P.U. 88-67 (Phase I) at 74; D.P.U. 84-94, at 50. Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure, unless the capital structure deviates substantially from sound utility practice. Mystic Valley Gas

Company v. Department of Public Utilities, 359 Mass. 420, 428-429 (1971); D.P.U. 22-22, at 357; High Wood Water Company, D.P.U. 1360, at 26-27 (1983); Blackstone Gas Company, D.P.U. 1135, at 4 (1982) (a company's capital structure that is composed entirely of common equity with no long-term debt varies substantially from usual utility practice); see also Cambridge Electric Light Company, D.P.U. 20104, at 42 (1979).

As noted above, Unitil proposes to increase its test-year balance of long-term debt by $20,600,000 (Exhs. Unitil-CGDN-1, at 69-70 (electric); Sch. RevReq-5 (Rev. 4) (electric); Unitil-CGDN-1, at 56-57 (gas); Sch. RevReq-5 (Rev. 4) (gas)). The Department finds that the Company's $20,600,000 long-term debt adjustment is a known and measurable change and accepts the Company's pro forma long-term debt balance of $112,500,000 (Exhs. Unitil-CGDN-1, at 69-70 (electric); Sch. RevReq-5 (Rev. 4) (electric); Unitil-CGDN-1, at 56-57 (gas); Sch. RevReq-5 (Rev. 4) (gas)).

Turning to the Company's pro forma common equity balance, the Company proposes an increase of $5,000,000 to its test-year-end balance of common equity to reflect post-test-year capital contributions from Unitil Corporation (Exhs. Unitil-CGDN-1, at 69 (electric); Unitil-TDAF-1, at 6 (electric); Sch. RevReq-5 (Rev. 4) (electric); Unitil-CGDN-1, at 56 (gas); Unitil-TDAF-1, at 6 (gas); Sch. RevReq-5 (Rev. 4) (gas)). While the Department accepts known and measurable changes to test-year-end capitalization, we examine parent holding company capital contributions for potential adverse rate effects because capital contributions are not subject to regulatory review under G.L. c. 164, § 14. D.P.U. 22-22, at 358; D.P.U. 15-80/D.P.U. 15-81, at 252-253; D.P.U. 14-150, at 317 n.197; D.P.U. 10-70, at 241-242. We find that Unitil has demonstrated that the post-test-year capital contributions from Unitil

Corporation are known and measurable and that the capital contributions were necessary for the Company to maintain its financial metrics and credit rating (Exhs. Unitil-TDAF-1, at 7-8 (electric); Unitil-TDAF-1, at 7-8 (gas)). Therefore, the Department accepts the Company's pro form common equity balance of $123,155,615 (Exhs. Sch. RevReq-5 (Rev. 4) (electric); Sch. RevReq-5 (Rev. 4) (gas)).

In support of her contention that the Company's proposed common equity ratio should be rejected, the Attorney General has neither argued nor presented evidence demonstrating that the Company's common equity ratio of 52.26 percent deviates substantially from sound utility practice. Rather, the Attorney General bases her position solely on her consultant's testimony that when a regulated utility's actual capital structure contains a high equity ratio the Department should: (1) impute a more reasonable capital structure; or (2) recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a lower ROE than the ROE for the proxy groups (Attorney General Brief at 25, citing Exh. AG-JRW-1, at 33). The Attorney General's contention alone does not meet the Department's standard to impute a capital structure. The Company's common equity ratio is consistent with those approved by the Department in recent years, and we conclude that such a ratio is not so weighted towards equity as to deviate substantially from sound utility practice or to impose an unfair burden on consumers. D.P.U. 22-22, at 359 (approving a 53.21-percent common equity ratio and rejecting the Attorney General's imputed capital structure); D.P.U. 20-120, at 382 (approving a 53.44-percent common equity ratio and rejecting the Attorney General's imputed capital structure); D.P.U. 19-120, at 344-346 (approving a 54.77-percent common equity ratio and rejecting the Attorney General's imputed capital structure); D.P.U. 18-150, at 450 & n.231 (approving a 53.49-percent common equity ratio and rejecting the Attorney General's imputed capital structure); D.P.U. 17-05, at 623-624 (approving 53.34-percent and 54.51 percent common equity ratios and rejecting the Attorney General's imputed capital structures). Therefore, the Department accepts the Company's proposal and will use a capital structure of $112,500,000 long-term debt and $123,155,615 common equity to determine each division's WACC (Exhs. Sch. RevReq-5 (Rev. 4) (electric); Sch. RevReq-5 (Rev. 4) (gas)). We address the Attorney General's alternative proposal that the Department should set a lower ROE because the Company's capital structure includes a higher common equity ratio than the proxy groups below.

C. Proxy Groups

1. Company Proposal

Unitil is a wholly owned subsidiary of Unitil Corporation and is not publicly traded; therefore, the Company has no public market for its stock (Exhs. Unitil-DWD-1, at 13-14 (electric); Unitil-DWD-1, at 13-14 (gas)). Accordingly, Unitil presents its ROE analysis using the capitalization and financial statistics of four proxy groups in total, i.e., two proxy groups for each division (Exhs. Unitil-DWD-1, at 4, 47-48 (electric); Unitil-DWD-3, Sch. 2 (electric); Unitil-DWD-1, at 4, 47-48 (gas); Unitil-DWD-3, Sch. 2 (gas)). For the Company's electric division, the first proxy group comprises 14 publicly traded utility companies engaged in the business of electric distribution service ("Electric Proxy Group"), and the second proxy group comprises 46 publicly traded domestic companies that purportedly have comparable total risk to the Electric Proxy Group ("Electric Non-Price Regulated Proxy Group") (Exh. Unitil-DWD-1, at 4, 14-15, 47-48 (electric)). For the Company's gas division, the first proxy group comprises six publicly traded utility companies engaged in the business of gas distribution service ("Gas Proxy Group"), and the second group comprises 43 publicly traded domestic companies that purportedly have comparable total risk to the Gas Proxy Group ("Gas Non-Price Regulated Proxy Group") (Exh. Unitil-DWD-1, at 4, 14-15, 47-48 (gas)).

2. Attorney General Proposal

The Attorney General uses three proxy groups to determine her proposed ROEs for the electric and gas divisions (Exhs. AG-JRW-1, at 25-28; JRW-3; AG-JRW-Surrebuttal-1, at 36). For the electric division, the Attorney General uses: (1) a group of 22 publicly held electric utility companies ("AG Electric Proxy Group"); and (2) the Company's Electric Proxy Group (Exhs. AG-JRW-1, at 26-27; AG-JRW-Surrebuttal-1, at 36). Initially, the Attorney General proposed a proxy group for the gas division of eight gas distribution companies (Exh. AG-JRW-1, at 27). During the proceeding, an acquisition disqualified two of the eight gas distribution companies that the Attorney General selected and, as a result, the Attorney General ultimately relies on the Company's Gas Proxy Group (Exh. AG-JRW-Surrebuttal-1, at 36). The Attorney General, however, states that she gives the Gas Proxy Group less weight than the electric proxy groups because the ROE results with such a small proxy group can be highly variable (Exhs. AG-JRW-1, at 27; AG-JRW-Surrebuttal-1, at 36).

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that Electric Proxy Group, Gas Proxy Group, and the AG Electric Proxy Group are low risk relative to the overall stock market and similar in risk to each other (Attorney General Brief at 28, citing Exh. AG-JRW-1, at 28). The Attorney General also maintains that the Department generally rejects the results of non-regulated proxy groups (Attorney General Brief at 26, citing D.T.E. 01-56, at 116; D.P.U. 96-50 (Phase I), at 132; D.P.U. 92-111, at 280-281; D.P.U. 905, at 48-49). The Attorney General claims that the lines of business of the companies in the Electric Non-Price Regulated Proxy Group and Gas Non-Price Regulated Proxy Group are vastly different from the electric distribution business and none of them operates in a highly regulated environment (Attorney General Brief at 28). Accordingly, the Attorney General argues that the Department should ignore the ROE results for the Electric Non-Price Regulated Proxy Group and Gas Non-Price Regulated Proxy Group (Attorney General Brief at 28).

b. Company

Unitil asserts that each of its four proxy groups has risk characteristics comparable to the Company (Company Brief at 327 (electric), citing Exh. Unitil-DWD-1, at 14 (electric); Company Brief at 260 (gas), citing Exh. Unitil-DWD-1, at 14 (gas)). The Company also contends that although the companies in the Electric Proxy Group and Gas Proxy Group are not identical to the Company in every aspect, the Department has recognized that it is neither necessary nor possible to find a group that matches the utility seeking relief in every detail (Company Brief at 328-329 (electric); Company Brief at 262 (gas), citing D.P.U. 09-30, at 307).

In addition, Unitil maintains that to determine the Company's allowed ROE, the Department may consider the cost of equity for companies that are not utilities so long as the companies are similar to Unitil with respect to their corresponding risks (Company Brief at 338 (electric); Company Brief at 282 (gas), citing Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944) ("Hope"); Bluefield Water Works & Improvement

Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692 (1923) ("Bluefield")). Moreover, the Company contends that the Department previously has accepted the use of non-regulated proxy companies in setting an allowed ROE (Company Brief at 329 (electric); Company Brief at 262 (gas), citing D.P.U. 13-75, at 302, 328; D.P.U. 12-25, at 416-417, 441). Unitil also claims that its selection criteria for the Electric Non-Price Regulated Proxy Group and the Gas Non-Price Regulated Proxy Group ensure that the groups have similar systematic risk profiles and diversifiable risk profiles to the Company and, thus, are similar in total risk relative to the Company (Company Brief at 329 (electric), citing Exh. Unitil-DWD-3, Sch. 6, at 3 (electric); Company Brief at 262 (gas), citing Exh. Unitil-DWD-3, Sch. 6, at 3 (gas)). Therefore, Unitil argues that the Electric Non-Price Regulated Proxy Group and the Gas Non-Price Regulated Proxy Group are appropriate proxy groups for the Department to consider (Company Brief at 338 (electric); Company Brief at 272 (gas)).

4. Analysis and Findings

a. Introduction

The use of a proxy group of companies is standard practice in setting an ROE that is comparable to returns on investments of similar risk. D.P.U. 22-22, at 380; D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82; D.P.U. 92-78, at 109-110; Western Massachusetts Electric Company, D.P.U. 1300, at 97 (1983). The use of a proxy group is especially relevant for evaluation of a cost of equity analysis when a distribution company does not have common stock that is publicly traded, as is the case with Unitil (Exhs. Unitil-DWD-1, at 13-14 (electric); Unitil-DWD-1, at 13-14 (gas)). D.P.U. 08-35, at 176-177; D.T.E. 99-118, at 80-82;

D.P.U. 92-78, at 109-110. The Department has stated that companies in the proxy group must have common stock that is publicly traded[200] and must be generally comparable in investment risk. D.P.U. 22-22, at 380; D.P.U. 1300, at 97.

In our evaluation of the proxy groups used by the Company and the Attorney General, we recognize that it is neither necessary nor possible to find a group in which the companies match Unitil in every detail. D.P.U. 22-22, at 380; Boston Gas Company, D.P.U. 1100, at 135-136 (1982). Rather, we may rely on an analysis that employs valid criteria to determine which companies will be in the proxy group and that provides sufficient financial and operating data to discern the investment risk of Unitil relative to the proxy group. D.P.U. 22-22, at 380-381; D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

The Department expects diligence by the parties in assembling proxy groups that will produce statistically reliable analyses required to determine a fair rate of return for the company. D.P.U. 22-22, at 381; D.P.U. 10-55, at 480-482. The Department has previously found that overly exclusive selection criteria may affect the statistical reliability of a proxy group if such screening criteria result in a limited number of companies in the proxy group. D.P.U. 22-22, at 381; D.P.U. 10-55, at 480-482.[201] The Department has directed parties to limit criteria to the

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200 An important aspect of the criteria for a proxy group is that financial information is readily available for publicly traded companies. D.P.U. 22-22, at 380 n.185; D.P.U. 15-80/D.P.U. 15-81, at 259 n.136.

201 The challenge when selecting a proxy group is to narrow it sufficiently to reflect the risks faced by the company in question and, at the same time, find a large enough proxy group to bring confidence to the ultimate result by mitigating any distortion introduced by possible measurement error or vagaries in an individual company's market data. In Re Public Service Company of New Hampshire, 90 NH PUC 230, 247 (2005).

extent necessary to develop a broader as opposed to a narrower proxy group. D.P.U. 22-22, at 381; D.P.U. 10-114, at 299; D.P.U. 10-55, at 481-482. To the extent that a particular company's characteristics differ from those of the others in a proxy group, those differences should be identified in sufficient detail to enable a reviewer to discern any effects on investment risk. D.P.U. 22-22, at 381; D.P.U. 10-55, at 480-482. Additionally, the Department places less reliance on a proxy group if the member companies are substantially different from the Company in the case. D.P.U. 22-22, at 381; D.P.U. 90-121, at 166.

b. Electric Proxy Group and AG Electric Proxy Group

After review, the Department finds that both the Company and the Attorney General have employed a set of valid criteria to select companies for inclusion in the Electric Proxy Group and the AG Electric Proxy Group, respectively (Exhs. Unitil-DWD-1, at 14-15 (electric); AG-JRW-1, at 25-26). In addition, the Department finds that both parties have provided sufficient information to draw conclusions about the relative risk profile of the Company relative to the risk profiles of the companies comprising the Electric Proxy Group and the AG Electric Proxy Group (Exhs. Unitil-DWD-1, at 14-15 (electric); Unitil-DWD-3, Sch. 2 (electric); AG-JRW-1, at 25-38; JRW-3). Therefore, the Department will accept the Electric Proxy Group and the AG Electric Proxy Group in determining the Company's allowed ROE.

c. Electric Non-Price Regulated Proxy Group

As noted above, Unitil argues that the Department previously accepted ROE estimates based on non-regulated companies in our determination of a utility's allowed ROE (Company Brief at 329 (electric); Company Brief at 262 (gas), citing D.P.U. 13-75, at 302, 328; D.P.U. 12-25, at 416-417, 441). Unitil does not present a complete picture of the Department's analysis in those cases. The Company fails to acknowledge that, in both proceedings, the Department stated that the non-regulated businesses were potentially riskier and, all else equal, potentially more profitable than the petitioning utility company, and the Department considered that disparity in risk in determining the appropriate ROE. D.P.U. 13-75, at 286-287; D.P.U. 12-25, at 402.[202] Ultimately, the Department authorized ROEs in those Orders that were, respectively, 303 basis points and 251 basis points lower than the discounted cash flow ("DCF") model results for the non-regulated business, which indicates that the Department placed limited weight on the ROE estimates based on the proxy group of non-regulated companies. D.P.U. 13-75, at 293, 329; D.P.U. 12-25, at 407, 444.

After review, we conclude that the record does not support a finding that the Electric Non-Price Regulated Proxy Group has sufficiently comparable investment risk to Unitil. The difference in investment risk is illustrated by the significant difference between the 9.95-percent Electric Proxy Group DCF model result, which is based on electric companies with comparable operations and financial risk to Unitil, and the 11.21-percent Electric Non-Price Regulated Proxy Group DCF model result (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 8 and 42 (electric)). The investor-required ROE reflects investors' assessment of the total investment risk of the subject firm (Exh. Unitil-DWD-1, at 10 (electric)). Therefore, we conclude that the significant difference between these DCF results indicates that investors do not view the investment risk of the Electric Proxy Group and Electric Non-Price Regulated Proxy Group as similar and,

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202 The Department has repeatedly found that the presence of unregulated operations in a proxy group would tend to produce model results that overstate a utility's cost of equity. D.P.U. 17-170, at 307; D.P.U. 15-80/D.P.U. 15-81, at 291-292; D.P.U. 10-114, at 335.

therefore, would not perceive the investment risk of Unitil as comparable to the investment risk of the Electric Non-Price Regulated Proxy Group (Exhs. Unitil-DWD-1, at 10 (electric); Unitil-DWD-Rebuttal-2, Sch. 1, at 8 and 42 (electric)). Another distinguishing factor of the Electric Non-Price Regulated Proxy Group is that it includes a number of companies that, unlike Unitil, have speculative grade credit ratings or have not been rated by Moody's Ratings ("Moody's) or Standard & Poor ("S&P") Global, Inc. Ratings ("S&P Ratings") (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 44 (electric)).[203] Therefore, the Department will not rely on the Electric Non-Price Regulated Proxy Group in our determination of the reasonable range and Unitil's allowed ROE.

d. Gas Proxy Group and Gas Non-Price Regulated Proxy Group

Based on the record evidence, the Department finds that the Gas Proxy Group is not sufficiently large and, as a result, the anomalous cost of equity results of two of the six companies disproportionately skew the mean and median of the entire group (Exhs. Unitil-DWD-Rebuttal-2, Sch. 2, at 6 (gas); AG-JRW-1, at 27; AG-JRW-Surrebuttal-1, at 36; Tr. 10, at 1002, 1049). Specifically, we find that Unitil's updated constant growth DCF model results for the Gas Proxy Group show significantly greater variance between the individual results relative to the variance between the individual DCF results for the Electric Proxy Group (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 8, Sch. 2, at 6 (gas)). The greater variance in the Gas Proxy Group is attributable to the DCF results for two of the companies in the Gas

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203 Moody's and S&P Ratings are providers of credit ratings, research, and risk analysis. Massachusetts Electric Company and New England Power Company, D.P.U. 20-61/D.P.U. 20-62, at 5 n.7 (2020).

Proxy Group of 12.17 percent and 12.37 percent (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 8, Sch. 2, at 6 (gas)). Compared to the mean DCF result of the other four companies in the Gas Proxy Group of 9.79 percent[204] and the mean DCF result for the 14 companies in the Electric Proxy Group of 9.96 percent, we find that the DCF results of 12.17 percent and 12.37 percent are outliers that disproportionately skew the mean and median DCF results of the Gas Proxy Group upward (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 8, Sch. 2, at 6 (gas)). For these reasons, we find that the Gas Proxy Group is composed of too few companies and is not statistically reliable. Therefore, we will not rely on the results of the Gas Proxy Group to determine Unitil's ROE. Furthermore, we will not rely on the results of the Gas Non-Price Regulated Proxy Group for the same reasons that we do not rely on the Electric Non-Price Regulated Proxy Group, stated above, and because the Company developed the Gas Non-Price Regulated Proxy Group based on the Gas Proxy Group (Exh. Unitil-DWD-1, at 47 (gas)).

As a result of our decisions to reject the Gas Proxy Group and the Gas Non-Regulated Proxy Group, the Department will set a single allowed ROE for Unitil's electric and gas divisions. We find that our decision is consistent with the Department's historical practice to authorize a single ROE when Unitil simultaneously files petitions for base distribution rate increases for both divisions. D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 11-01/D.P.U. 11-02, at 409-412; D.T.E. 02-24/25, at 225; Fitchburg Gas and Electric Light Company, D.P.U. 1214-D at 4-5 (1985). In the past, the Department reasoned that a single ROE for Unitil's electric and gas divisions is appropriate because the Company's operating divisions are part of a single

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204 (10.29 + 9.78 + 9.54 + 9.54) / 4 = 9.79

corporate structure that reports financial information on a consolidated basis, including combined statements of earnings, retained earnings, cash flow, and long-term debt, and investors make decisions based on the Company's overall risk. D.P.U. 11-01/D.P.U. 11-02, at 411; D.P.U. 1214, at 57-58. As the record in the instant proceeding shows, these attributes of the operating divisions have not changed: (1) the Company's electric and gas divisions remain part of a single corporate structure with consolidated financial statements of earnings, retained earnings, cash flow and long-term debt; (2) debt is issued for the Company as a whole, with credit ratings issued for the joint company and proceeds available for both divisions; (3) permanent capital sources are available to both divisions; and (4) investors make decisions based on the risk profile of the Company as a combined utility (Tr. 7, at 636-637, 720-721). Accordingly, we reaffirm that it is appropriate for the Department to authorize a single ROE for the Company's electric and gas divisions based on Unitil's corporate structure and overall risk. Furthermore, we find that the Electric Proxy Group and AG Electric Proxy Group are sufficiently comparable to Unitil as a whole because: (1) seven of the 14 companies in the Electric Proxy Group are combination gas and electric distribution companies like Unitil; and (2) the average credit rating from Moody's and S&P Ratings for the Electric Proxy Group and the AG Electric Proxy Group are the same as Unitil's credit ratings (Exhs. Unitil-DWD-Rebuttal-2, Sch. 1, at 27 (electric); AG-JRW-Surrebuttal-1, at 2-3, 10; Tr. 7, at 724).

D. Return on Equity

1. Company Proposal

a. Overview

Unitil's proposed a 10.50-percent ROE for its electric division and a 10.75-percent ROE for its gas division (Exhs. Unitil-DWD-1, at 5 (electric); Unitil-DWD-1, at 5 (gas)). To determine its proposed ROEs, the Company applied the following ROE estimation models to the market data of its four proxy groups: (1) the DCF model; (2) two variations of the capital asset pricing model—the traditional capital asset pricing model ("CAPM") and the empirical CAPM; and (3) two variations of the bond-yield plus risk premium model that the Company identified as the predictive risk premium model ("PRPM") and the total market approach risk premium model ("MRPM") (Exhs. Unitil-DWD-1, at 4-5 (electric); Unitil-DWD-1, at 4-5 (gas)).[205] In addition, Unitil proposed adjustments to the model results for Unitil's size, Unitil's credit risk, and flotation costs (Exhs. Unitil-DWD-1, at 51-60 (electric); Unitil-DWD-1, at 51-60 (gas)). In the Company's initial filing, Unitil used market data as of May 31, 2023 (Exhs. Unitil-DWD-1, at 24 (electric); Unitil-DWD-1, at 24 (gas)). Unitil provided updated model results with its rebuttal testimony using market data as of November 30, 2023 (Exhs. Unitil-DWD-Rebuttal-1, at 2 (electric); Unitil-DWD-Rebuttal-1, at 2 (gas)).

205 The CAPM, empirical CAPM, PRPM, and MRPM are all risk premium-based methods to determine a company's cost of equity (Exhs. Unitil-DWD-1, at 23 (electric); Unitil-DWD-1, at 23 (gas)).

b. DCF Model

In the Company's DCF analyses, the required ROE equals the sum of the expected dividend yield and the expected long-term growth rate (Exhs. Unitil-DWD-1, at 23-24 (electric); Unitil-DWD-1, at 23-24 (gas)). To calculate the expected dividend yield, the Company divides each proxy company's annualized dividends by the company's 60-day average closing market price and multiplies the result by one-half of its expected long-term growth rate (Exhs. Unitil-DWD-1, at 24-25 (electric); Unitil-DWD-1, at 24-25 (gas)).[206] For the expected long-term growth rate, the Company used five-year projected EPS growth rates of the proxy companies provided by Yahoo! Finance, Zacks Investment Research, and Value Line Investment Survey ("Value Line") (Exhs. Unitil-DWD-1, at 25 (electric); Unitil-DWD-1, at 25 (gas)).

Unitil's initial DCF results were: (1) 9.43 percent for the Electric Proxy Group; (2) 9.60 percent for the Gas Proxy Group; (3) 10.83 percent for the Electric Non-Price Regulated Group; and (4) 10.71 percent for the Gas Non-Price Regulated Proxy Group (Exhs. Unitil-DWD-1, at 25-26, 50 (electric); Unitil-DWD-3, Sch. 3, at 1, Sch. 7, at 2 (electric); Unitil-DWD-1, at 26, 50 (gas); Unitil-DWD-3, Sch. 3, at 1, Sch. 7, at 2 (gas)). The Company's updated DCF results were: (1) 9.95 percent for the Electric Proxy Group; (2) 10.32 percent for the Gas Proxy Group; (3) 11.21 percent for its Electric Non-Price Regulated Group; and (4) 10.69 percent for its Gas Non-Price Regulated Group (Exhs. Unitil-DWD-Rebuttal at 4

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206 This adjustment to the dividend yield is made because dividends are paid periodically rather than daily and, therefore, a dividend yield derived from the price data of a previous period can be reasonably adjusted for the coming period by one-half of the annual dividend growth rate (Exhs. Unitil-DWD-1, at 24-25 (electric); Unitil-DWD-1, at 24-25 (gas)).

(electric); Unitil-DWD-Rebuttal-2, Sch. 1, at 8, 42, Sch. 2, at 6, 32 (electric); Unitil-DWD-Rebuttal at 4 (gas); Unitil-DWD-Rebuttal-2, Sch. 1, at 8, 42, Sch. 2, at 6, 32 (gas)).

c. CAPM and Empirical CAPM

The Company's CAPM analyses include three components to calculate the cost of equity: (1) a risk-free rate of return; (2) beta coefficients for the proxy group companies;[207] and (3) a market risk premium ("MRP") (Exhs. Unitil-DWD-1, at 40-41 (electric); Unitil-DWD-1, at 40-41 (gas)). The empirical CAPM applies a 75 percent weighting to the product of the beta coefficient and the MRP and a 25 percent weighting to the MRP alone (Exhs. Unitil-DWD-1, at 41-43 (electric); Unitil-DWD-1, at 41-43 (gas)). The Company states that the empirical CAPM adjusts for the CAPM's tendency to understate returns for companies with low betas, such as utilities, and to overstate returns for companies with high betas (Exhs. Unitil-DWD-1, at 41-43 (electric); Unitil-DWD-1, at 41-43 (gas)).

For the risk-free rate of return, the Company used an average of projected 30-year U.S. Treasury bonds yields from Blue Chip Financial Forecasts (Exhs. Unitil-DWD-1, at 44 (electric); Unitil-DWD-Rebuttal-2, at Sch. 1, at 36-37; Sch. 2, at 26-27 (electric); Unitil-DWD-1, at 44 (gas); Unitil-DWD-Rebuttal-2, at Sch. 1, at 36-37; Sch. 2, at 26-27 (gas)). Unitil uses beta coefficients of the proxy group companies sourced from Value Line and Bloomberg Professional Services (Exhs. Unitil-DWD-1, at 44 (electric); Unitil-DWD-1, at 44 (gas)).

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207 CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by the beta coefficient (Exhs. Unitil-DWD-1, at 40 (electric); Unitil-DWD-1, at 41 (gas)).

Unitil derived its CAPM MRP from the average of three MRPs based on historical data and three MRPs based on projected data (Exhs. Unitil-DWD-1, at 44-46 (electric); Unitil-DWD-3, Sch. 5, at 2 (electric); Unitil-DWD-Rebuttal-2, Sch. 1, at 37, Sch. 2, at 27 (electric); Unitil-DWD-1, at 44-46 (gas); Unitil-DWD-3, Sch. 5, at 2 (gas); Unitil-DWD-Rebuttal-2, Sch. 1, at 37, Sch. 2, at 27 (gas)). The Company calculates the six MRPs using the following: (1) the historical spread between total returns of large stocks and long-term government bond yields from 1926-2022 ("MRP Measure 1"); (2) a linear ordinary least square regression of the monthly annualized historical returns on the S&P 500 Index[208] relative to historical yields on long-term government securities from 1926 to 2023 ("MRP Measure 2"); (3) application of the PRMP relative to the yields on long-term U.S. Treasury securities from 1926-2023 ("MRP Measure 3"); (4) projected total annual market return of the Value Line universe of companies less the risk-free rate ("MRP Measure 4"); (5) projected total return of the S&P 500 Index using dividend yields and projected EPS growth rates from Value Line as a proxy for capital appreciation less the risk-free rate ("MRP Measure 5"); and (6) projected total return of the S&P 500 Index using dividend yields and projected EPS growth rates from Bloomberg Professional Services as a proxy for capital appreciation less the risk-free rate ("MRP Measure 6") (Exhs. Unitil-DWD-1, at 35-36, 44-46 (electric); Unitil-DWD-3, Sch. 5 (electric); Unitil-DWD-Rebuttal-2, Sch. 1, at 37, Sch. 2, at 27 (electric); Unitil-DWD-1,

[208] The S&P 500 Index is an American stock market index based on the market capitalizations of 500 large companies having common stock listed on the New York Stock Exchange or the NASDAQ Stock Market. D.P.U. 17-05, at 686 n.365.

at 35-36, 44-46 (gas); Unitil-DWD-3, Sch. 5 (Gas); Unitil-DWD-Rebuttal-2, Sch. 1, at 37, Sch. 2, at 27 (gas)).[209]

Unitil averaged the individual results of the CAPM and the empirical CAPM for each company in each of the proxy groups and then took the average of the mean and median results of each proxy group (Exhs. Unitil-DWD-3, Sch. 5, at 1 (electric); Unitil-DWD-3, Sch. 5, at 1 (gas); Unitil-DWD-Rebuttal-2, Sch. 1, at 36, Sch. 2, at 26; DPU 34-11 (electric); DPU 29-11 (gas)). Unitil's initial CAPM and empirical CAPM results were: (1) 11.48 percent for the Electric Proxy Group; (2) 11.37 percent for the Gas Proxy Group; (3) 12.50 percent for the Electric Non-Price Regulated Proxy Group; and (4) 11.93 percent for the Gas Non-Price Regulated Proxy Group (Exhs. Unitil-DWD-1, at 5, 46 (electric); Unitil-DWD-3, Sch. 5, at 1, Sch. 7, at 1 (electric); Unitil-DWD-1, at 5, 46 (gas); Unitil-DWD-3, Sch. 5, at 1, Sch. 7, at 1 (gas)). The updated results of the Company's analysis were: (1) 12.51 percent for the Electric Proxy Group; (2) 12.52 percent for the Gas Proxy Group; (3) 13.43 percent for the Electric Non-Price-Regulated Proxy Group; and (4) 13.13 percent for the Gas Non-Price Regulated Proxy Group (Exhs. Unitil-DWD-Rebuttal at 4; Unitil-DWD-Rebuttal-2, Sch. 1, at 36, 41; Sch. 2, at 26, 31).

d. PRPM and MRPM

Unitil calculated the PRPM cost of equity using: (1) a projected equity risk premium ("ERP") derived from the historical returns of each company in the Electric Proxy Group and the

[209] Some companies in the S&P 500 Index do not pay dividends, leaving those companies' projected EPS growth rate as the proxy for capital appreciation in Unitil's MRP Measure 5 and MRP Measure 6 (Exhs. Unitil-DWD-3, MRP WP2, MRP WP3 (electric); Unitil-DWD-3, MRP WP2, MRP WP3 (gas); Tr. 7, at 748-750).

Gas Proxy Group less the historical monthly yield on 30-year U.S. Treasury bonds; and (2) the risk-free rate of return used for the CAPM (Exhs. Unitil-DWD-1, at 27-29 (electric); Unitil-DWD-1, at 27-29 (gas)). The Company calculated the ERP for the PRPM using a generalized autoregressive conditional heteroskedasticity model to analyze variance patterns in historical equity risk premiums and predict an equity risk premium (Exhs. Unitil-DWD-1, at 27-28 (electric); Unitil-DWD-1, at 27-28 (gas)).

The Company's MRPM includes two inputs to calculate the cost of equity: (1) an ERP; and (2) a prospective public utility bond yield (Exhs. Unitil-DWD-1, at 29-30 (electric); Unitil-DWD-1, at 30 (gas)). Unitil derives the ERP from the average of: (1) a beta-adjusted ERP ("ERP Measure 1"); (2) an average of five ERPs based on the S&P Utilities Index ("ERP Measure 2"); and (3) an ERP based on authorized ROEs for electric (or gas) distribution utilities ("ERP Measure 3") (Exhs. Unitil-DWD-1, at 29-30 (electric); Unitil-DWD-1, at 30 (gas)). ERP Measure 1 is the average of the same six sources of market return data as the six CAPM MRPs, discussed above, less historic corporate bond yields for the historic market returns and forecast corporate bond yields for the projected market returns (Exhs. Unitil-DWD-1, at 34-35, 44-45 (electric); Unitil-DWD-3, Sch. 4, at 9 (electric); Unitil-DWD-1, at 34-35, 44-45 (gas); Unitil-DWD-3, Sch. 4, at 9 (gas)). ERP Measure 2 is the average of three ERPs based on S&P Utility Index holding returns and two ERPs based on expected returns of the S&P Utility Index (Exhs. Unitil-DWD-1, at 44-45 (electric), Unitil-DWD-3, Sch. 4, at 9 (electric); Unitil-DWD-1, at 44-45 (gas), Unitil-DWD-3, Sch. 4, at 9 (gas)). ERP Measure 3 is the result of a regression analysis based on regulatory awarded ROEs relative to public utility bonds

(Exhs. Unitil-DWD-1, at 44-45 (electric), Unitil-DWD-3, Sch. 4, at 9 (electric); Unitil-DWD-1, at 44-45 (gas), Unitil-DWD-3, Sch. 4, at 9 (gas)).

Unitil proposed to average the results of the PRPM and MRPM in its determination of the reasonable range of ROEs (Exhs. Unitil-DWD-1, at 40 (electric); Unitil-DWD-1, at 40 (gas)). Unitil's initial average results for the PRPM and MRPM were: (1) 11.48 percent for the Electric Proxy Group; (2) 11.36 percent for the Gas Proxy Group; (3) 13.03 percent for the Electric Non-Price Regulated Proxy Group; and (4) 12.68 percent for the Gas Non-Price Regulated Proxy Group (Exhs. Unitil-DWD-3, Sch. 4, at 1, Sch. 7, at 1 (electric), Unitil-DWD-3, Sch. 4, at 1, Sch. 7, at 1 (gas)). The Company's updated average of the PRPM and MRPM are: (1) 11.72 percent for the Electric Proxy Group; (2) 11.03 percent and the Gas Proxy Group; (3) 13.95 percent for the Electric Non-Price Regulated Proxy Group; and (4) 13.68 percent for the Gas Non-Price Regulated Proxy Group (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 2, 23, 41, Sch. 2, at 2, 13, 31).

e. Company Adjustments

In its initial filing, Unitil determined its proposed electric and gas division ROEs based on the ROE model results discussed above with three adjustments. First, the Company proposed an increase of 0.15 percent to each range to reflect the Company's smaller size and, therefore, greater business risk relative to the Electric Proxy Group and Gas Proxy Group (Exhs. Unitil-DWD-3, at Sch. 1, at 2 (electric); Unitil-DWD-3, at Sch. 1, at 2 (gas)). Second, Unitil proposed an increase of 0.06 percent to the range for the electric division and 0.22 percent to the range for the gas division to reflect the lower credit rating of the Company relative to the A2 average Moody's bond rating of the Electric Proxy Group and the Gas Proxy Group

(Exhs. Unitil-DWD-3, at Sch. 1, at 2 (electric); Unitil-DWD-3, at Sch. 1, at 2 (gas)). Finally, the Company proposed increases of 0.47 percent to the range for the electric division and 0.38 percent to the range for the gas division to recognize the flotation costs of issuing equity for the parent company (Exhs. Unitil-DWD-3, at Sch. 1, at 2 (electric); Unitil-DWD-3, at Sch. 1, at 2 (gas)). Based on the data submitted during the proceeding, Unitil revised the adjustments to: (1) 0.15 percent to each range for the Company's size; (2) no adjustment to the range for the electric division and 0.18 percent to the range for the gas division for the Company's credit rating; and (3) 0.47 percent for the electric division and 0.45 percent for the gas division for flotation costs (Exhs. Unitil-DWD-1, at 57 (electric); Unitil-DWD-1, at 57 (gas); Unitil-DWD-Rebuttal-2, Sch. 1, at 2, Sch. 2, at 2).

f. Investment Risk and Required ROE

Unitil proposed to combine its model results to determine a reasonable range of the cost of equity for each division (Exh. Unitil-Rebuttal at 4). The Company's reasonable range for each division comprises the range of the following: (1) the average of the mean and median DCF results; (2) the average of the PRPM and MRPM results; (3) the average of the mean and median of the average CAPM and empirical CAPM results; and (4) the average of the model results for the Non-Price Regulated Proxy Groups (Exhs. Unitil-Rebuttal at 4; Unitil-Rebuttal-2, Sch. 1, at 2, Sch. 2, at 2). After applying adjustments for credit risk, size, and flotation costs, the Company's proposed cost of equity ranges are: (1) 10.57 percent to 13.77 percent for the electric division; and (2) 11.10 percent to 13.60 percent for the gas division (Exhs. Unitil-Rebuttal at 4; Unitil-Rebuttal-2, Sch. 1, at 2, Sch. 2, at 2).

The Company states that the cost of equity increased during the proceeding and interest rates and inflation continue to have an upward impact on capital costs (Exh. Unitil-DWD-Rebuttal at 2, 5, 8). Nonetheless, the Company requested that the Department allow the ROEs initially proposed of 10.50 percent for the electric division and 10.75 percent for the gas division in recognition of the energy burdens of its customers (Exhs. Unitil-DWD-Rebuttal at 2, 5; Unitil-RBH-Rebuttal at 35 (electric); Unitil-DJH-Rebuttal at 28 (gas)).

Additionally, Unitil states that the EDCs and LDCs in Massachusetts operate in an environment that is undergoing a fundamental transition as a result of policy and legislative initiatives designed to promote safety and reliability, address climate change, and encourage a clean energy economy (Exhs. Unitil-RBH-1, at 13-15 (electric); Unitil-DJH-1, at 13-16 (gas)). The Company also states that, under its proposed PBR plans, it is at risk of over- or under-earning its return if it does not manage its costs (Exhs. Unitil-RBH-1, at 54 (electric); Unitil-DJH-1, at 39 (gas)). Unitil explains that its specific business risks must be considered in determining the Company's cost of equity (Exhs. Unitil-DWD-1, at 13-12 (electric); Unitil-DWD-1, at 13-12 (gas)).

2. Attorney General Proposal

a. Overview

The Attorney General recommended that the Department authorize an 8.85-percent ROE for the Company's electric division and an 8.45-percent ROE for the Company's gas division (Attorney General Brief at 61-62; Exh. AG-JRW-1, at 4-5). The Attorney General explained that her recommended ROE for each division is based on: (1) the results of her consultant's initial

DCF and CAPM analyses; and (2) Unitil's overall cost of service compared with the other Massachusetts EDCs (Attorney General Brief at 61-62; Exh. AG-JRW-1, at 4-5).

b. DCF Model

The Attorney General relied on the same DCF model as the Company, i.e., the required ROE is equal to the sum of the expected dividend yield and the expected long-term growth rate (Exh. AG-JRW-1, at 45). Unlike Unitil, however, the Attorney General's DCF model considered several measures of projected long-term growth rather than relying exclusively on projected EPS growth rates (Exh. AG-JRW-1, at 47-48). The Attorney General derived her long-term growth rate based on the following: (1) projected sustainable growth rates sourced from Value Line; (2) projected EPS, dividends per share ("DPS"), and book value per share ("BVPS") growth rates sourced from Value Line; and (3) projected EPS growth rates sourced from Wall Street analysts provided by Yahoo! Finance, Zacks Investment Research, and S&P Capital IQ (Exh. AG-JRW-1, at 47-48). The Attorney General gave primary weight to the projected EPS growth rates sourced from Wall Street analysts provided by Yahoo! Finance, Zacks Investment Research, and S&P Capital IQ but recognizes the presence of upward bias in these forecasts (Exhs. AG-JRW-1, at 54-58, 119; AG-JRW-Surrebuttal-1, at 37-39).

The Attorney General's initial DCF results were 9.60 percent for the AG Electric Proxy Group, 9.45 percent for the Electric Proxy Group, and 9.45 percent for her proxy group of eight gas distribution companies (Exhs. AG-JRW-1, at 58; JRW-5).[210] Her updated DCF results were

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210 As discussed above, the Attorney General initially proposed a proxy group for the gas division of eight gas distribution companies but ultimately relied on the Company's Gas Proxy Group (Exhs. AG-JRW-1, at 27; AG-JRW-Surrebuttal-1, at 36).

9.65 percent for the AG Electric Proxy Group, 9.40 percent for the Electric Proxy Group, and 9.70 percent for the Gas Proxy Group (Exh. AG-JRW-Surrebuttal-1, at 40).

c. CAPM

The Attorney General's CAPM analyses included the same three components as the Company's CAPM analyses: (1) a risk-free rate of return; (2) a beta derived from the beta coefficients of the companies in the proxy groups; and (3) an MRP (Exh. AG-JRW-1, at 59). Initially, the Attorney General used 4.40 percent for her risk-free rate of return, which was derived from the yields on 10-year, 20-year, and 30-year U.S. Treasury bonds (Exh. AG-JRW-1, at 60-61). In the Attorney General's updated CAPM analyses, however, she used 4.25 percent, which represents a spot yield on the 30-year U.S. Treasury bond at the time of her preparation of her updated filing (Exh. AG-JRW-Surrebuttal-1, at 40). The Attorney General derived a 5.25-percent MRP from various MRP studies and surveys of financial professionals (Exhs. AG-JRW-Surrebuttal-1, at 40; AG-JRW-1, at 73).

Based on the above-noted inputs, the Attorney General's initial CAPM results were: (1) 8.85 percent for the AG Electric Proxy Group; (2) 8.85 percent for the Electric Proxy Group; and (3) 8.45 percent for her initial proxy group of eight gas distribution companies (Exh. JRW-6, at 1). Her updated CAPM results were: (1) 8.40 percent for the AG Electric Proxy Group; (2) 8.75 percent for the Electric Proxy Group; and (3) 8.35 percent for the Gas Proxy Group (Exhs. AG-JRW-Surrebuttal-1, at 41; JRW-11, at 1).

d. Market Conditions and Trends on Authorized ROEs

The Attorney General stated that the year-over-year inflation rate has been higher in the short-term, but the yields on Treasury inflation-protected securities suggest longer-term inflation expectations are 2.25 percent (Exh. AG-JRW-1, at 18). Additionally, she stated that an inverted yield curve suggests that the prospect of a recession is likely, which would lead to lower interest rates (Exh. AG-JRW-1, at 18). Further, the Attorney General noted that over the past four decades authorized ROEs have not declined in line with capital costs and, therefore, past authorized ROEs have overstated the actual cost of equity (Exh. AG-JRW-1, at 25). As a result, the Attorney General stated that the Department should not be concerned that her consultant's recommended ROE is below other authorized ROEs (Exh. AG-JRW-1, at 25).

3. Positions of the Parties

a. Attorney General

i. ROE Estimation Models

(A) DCF Model

The Attorney General argues that the Department should reject the Company's DCF results because they overstate the cost of equity by exclusively using overly optimistic and upwardly biased EPS growth rate forecasts (Attorney General Brief at 31, citing Exh. AG-JRW-1, at 79). She contends that the three empirical studies in the evidentiary record demonstrate that: (1) analysts' long-term EPS growth rate forecasts are not more accurate at forecasting future earnings than naïve random walk forecasts of future earnings; (2) using Wall Street analysts' long-term EPS growth rates in the DCF model leads to an upward bias in ROE estimates of almost three percentage points; and (3) Value Line's three-to-five-year EPS growth rate forecasts are significantly higher than the EPS growth rates actually achieved (Attorney General Brief at 32-33, citing Exh. AG-JRW-1, at 50-55). Additionally, the Attorney General maintains that her analysis of EPS growth rates for electric utilities over the period from 1985 to

2022 shows that the mean projected three-to-five-year EPS growth rate is over two percentage points above the actual mean three-to-five-year EPS growth rate for electric utilities over the period, reflecting that projected EPS growth rates for electric utilities are overly optimistic and upwardly biased (Attorney General Brief at 32-33, citing Exh. AG-JRW-1, at 53).

(B) CAPM and Empirical CAPM

The Attorney General argues that the two primary errors with the Company's CAPM are the use of the empirical CAPM and the Company's overstated MRP (Attorney General Brief at 37-39, citing Exh. AG-JRW-1, at 66-74, 90-111). The Attorney General asserts that the Department should use a 5.25-percent MRP in any CAPM analysis used to determine Unitil's ROE in this proceeding (Attorney General Brief at 38).

The Attorney General avers that there are several empirical issues associated with computing an ex-ante market risk premium based on historical stock and bond returns, as Unitil proposes for MRP Measures 1-3 (Attorney General Brief at 41, citing Exh. AG-JRW-1, at 85-89). She argues that this approach can produce differing results depending on the analyst's choice of central tendency, time period to evaluate, and stock market index to employ (Attorney General Brief at 41, citing Exh. AG-JRW-1, at 85-89). Further, the Attorney General asserts that such an approach suffers from several flaws, including U.S. stock market survivorship bias, company survivorship bias, change in risk and required return over time, downward bias in bond historical returns, and unattainable return bias (Attorney General Brief at 41, citing Exh. AG-JRW-1, at 85-89).

Additionally, the Attorney General argues that the Company's projected market returns used to calculate MRP Measures 4-6 are excessive and unrealistic because the compounded annual return of the U.S. stock market between 1928 and 2022 is about ten percent (Attorney General Brief 43-44, citing Exh. AG-JRW-1, at 92-98). Further, she asserts that the Department should reject the Company's MRP Measures 4-6 because Unitil calculates market returns for the S&P 500 Index using upwardly biased three-to-five-year EPS projections (Attorney General Brief at 45-46, citing Exh. AG-JRW-1, at 96-97). The Attorney General also claims that MRP Measures 4-6 are overstated because long-term EPS and economic growth is about one half of the 11.98 percent average long-term EPS growth rate used in the Company's CAPM (Attorney General Brief at 47, citing Exh. AG-JRW-1, at 95-108). According to the Attorney General, long-term EPS growth rates are directly linked to GDP growth and recent GDP growth trends, and near-term GDP projections suggest slower growth in both GDP and earnings during the period in which the rates will be in effect (Attorney General Brief at 47, citing Exh. AG-JRW-1, at 95-108).

Regarding her recommended MRP, the Attorney General contends that she surveyed 31 investment firms and their long-term estimates of expected annual stock returns fall between 4.00 percent to 9.50 percent, with a 6.87 percent mean and 1.28 standard deviation (Attorney General Brief at 44, citing Exhs. AG-JRW-1, at 92-95, JRW-8). She argues that the Company's average MRP based on projected data greatly exceeds the MRPs: (1) found in studies of the market risk premiums by leading academic scholars; (2) measured by historic stock and bond returns; and (3) found in surveys of financial professionals (Attorney General Brief at 45, citing Exh. AG-JRW-1, at 91-92).

Finally, the Attorney General urges the Department to reject the results of the empirical CAPM (Attorney General Brief at 39-40). She asserts that: (1) the empirical CAPM has not been theoretically or empirically validated in referenced journals; and (2) the adjusted betas from Value Line already address the purported empirical issues with the CAPM (Attorney General Brief at 39-40, citing Exh. AG-JRW-1, at 110).

(C) PRPM and MRPM

The Attorney General contends that the Department should reject the results of Unitil's PRPM and MRPM because the Company's ERPs suffer from the same flaws as the MRPs discussed above (Attorney General Brief at 51, citing Exh. AG-JRW-1, at 84). She argues that, like the CAPM, the primary issue with the results of the PRPM and MRPM is the magnitude and measurement of the ERPs (Attorney General Brief at 51, citing Exh. AG-JRW-1, at 84). Specifically, the Attorney General claims that the ERPs based on historical stock and bond returns suffer from the same empirical problems as the Company's MRPs based on historical data (Attorney General Brief at 51, citing Exh. AG-JRW-1, at 84). Further, she asserts that Unitil repeats the same errors with the projected returns as in the Company's CAPM and, therefore, relies on unrealistic expected market returns to produce an inflated ROE (Attorney General Brief at 51, citing Exh. AG-JRW-1, at 84).

(D) Adjustments

The Attorney General argues that the Department should reject all three of the Company's proposed adjustments (Attorney General Brief at 51-53). She argues that an adjustment based on size is not appropriate for public utilities because utilities are subject to regulation, government oversight, performance review, accounting standards, and information disclosure, which distinguish them from industrials and accounts for the lack of a size premium (Attorney General Brief at 23, 52-53, citing Exh. AG-JRW-1, at 10, 114-116). In addition, the

Attorney General argues that a credit risk adjustment is not appropriate for Unitil because the S&P Ratings and Moody's credit ratings for the Company are equal to the averages of the AG Electric Proxy Group and the Electric Proxy Group (Attorney General Brief at 23, 51, citing Exh. AG-JRW-1, at 10).

Finally, the Attorney General argues that the Department should not allow a flotation cost adjustment since there is no evidence that Unitil incurred flotation costs (Attorney General Brief at 24 & n.18, 52, citing Exh. AG-JRW-1, at 10). She contends that the Department consistently has rejected the inclusion of flotation costs in the cost of service (Attorney General Brief at 24, citing D.P.U. 90-121, at 180; D.P.U. 88-67 (Phase I) at 193; D.P.U. 86-280-A at 112; D.P.U. 85-137, at 100). According to the Attorney General, the Department has found that the use of a flotation cost adjustment to ROE is not appropriate because investors already take into account issuance costs in their decision to purchase the stock at a given price (Attorney General Brief at 24 n.18, citing D.P.U. 90-121, at 180; D.P.U. 88-67 (Phase I) at 193; D.P.U. 86-280-A at 112; D.P.U. 85-137, at 100). Further, she argues that utilities that are part of a holding company structure do not have flotation costs and issuance costs are negligible because all stock is issued to the parent company of the holding company (Attorney General Brief at 24 n.18, citing Massachusetts Electric Company, D.P.U. 800, at 51 (1982); Western Massachusetts Electric Company, D.P.U. 20279, at 37 (1980); Massachusetts Electric Company, D.P.U. 19376, at 7-13 (1979)). Finally, the Attorney General claims that the Company has not provided any new evidence or arguments to change the Department's well-established precedent on flotation costs (Attorney General Brief at 24 n.18).

ii. Market Conditions and Trends in Authorized ROEs

The Attorney General asserts that a strong economy and high inflation resulted in an increase in 30-year Treasury yields in 2022 and 2023, peaking at over 5.0 percent in the fall of 2023 and declining to around 4.40 percent at the time of this proceeding (Attorney General Brief at 54, citing Exh. AG-JRW-1, at 13). Further, the Attorney General claims that the expected inflation rate over the next five years is 2.40 percent and the expected inflation rates over the next ten and 30 years are about 2.25 percent (Attorney General Brief at 55-56, citing Exh. AG-JRW-1, at 15). Further, she argues that in the last five years authorized ROEs in the Commonwealth for EDCs and LDCs were still in the range of 9.70 percent to 9.90 percent and did not decline with interest rates and capital costs (Attorney General Brief at 57, citing Exh. AG-JRW-1, at 22). The Attorney General also contends that Massachusetts ROEs have consistently been 30 to 50 basis points above the authorized ROEs for electric distribution companies nationally (Attorney General Brief at 57, citing Exh. AG-JRW-1, at 22). In sum, the Attorney General asserts that her consultant's study examining the relationship between authorized ROEs for utilities and interest rates over the last five years found that while authorized ROEs for utilities reached record low levels in the last two years, utility ROEs never declined to the extent that interest rates declined (Attorney General Brief at 58-59, citing Exh. AG-JRW-1, at 20-21).

iii. Required ROE

The Attorney General argues that Unitil has the highest delivery rates of the Massachusetts utilities and the difference between the Company's delivery rates and other utilities' delivery rates is unreasonable and due to management or operational inefficiencies

(Attorney General Brief at 59-60; Attorney General Reply Brief at 1-3). The Attorney General contends that Unitil's higher cost of service as compared to other Massachusetts EDCs and LDCs should not be passed on to the Company's customers or benefit the Company's management and shareholders (Attorney General Brief at 60-62). Accordingly, the Attorney General recommends that the Department authorize: (1) an ROE of 8.85 percent for the electric division based on the low end of her initial ROE results for the AG Electric Proxy Group and Electric Proxy Group; and (2) an ROE of 8.45 percent for the gas division based on the low end of her initial ROE results for the Gas Proxy Group (Attorney General Brief at 61).

b. Company

i. ROE Estimation Models

(A) DCF Model

Unitil argues that the most relevant measure of growth for the DCF model is the growth rate that investors actually expect (Company Brief at 339 (electric); Company Brief at 273 (gas)). The Company claims that EPS growth is the appropriate expected growth rate because it is the fundamental driver of both book value and dividend growth (Company Brief at 339 (electric); Company Brief at 273 (gas), citing Exh. Unitil-DWD-Rebuttal at 35). According to the Company, a DCF-estimated cost of equity must recognize and reflect the fact that it is the EPS growth rate expectations of investors that drive stock prices and that these expectations are influenced by analysts' forecasts (Company Brief at 341 (electric); Company Brief at 275 (gas)).

Further, Unitil argues that the Department must reject the Attorney General's DCF calculation because she relies excessively on DPS, BVPS, historical growth rates, and retention growth rates (Company Brief at 339 (electric); Company Brief at 273 (gas)). The Company asserts that DPS, BVPS, historical growth rates, and retention growth rates are not widely relied upon or referenced by investors (Company Brief at 339 (electric); Company Brief at 273 (gas), citing Exh. Unitil-DWD-Rebuttal at 35-43). Unitil also claims that historical growth rates are already reflected in analysts' earnings estimates to the extent they influence investors' expectations and that the use of retention growth rates is inappropriate because they are circular in nature (Company Brief at 339 (electric); Company Brief at 273 (gas), citing Exh. Unitil-DWD-Rebuttal at 37-38). Additionally, the Company contends that unlike EPS growth rates, Value Line is the only source for DPS and BVPS growth rates and that reliance on one source for a growth measure can bias the DCF calculation (Company Brief at 339 (electric); Company Brief at 273 (gas)).

Additionally, Unitil avers that Wall Street analysts' long-term EPS growth rates are not overly optimistic or upwardly biased (Company Brief at 340 (electric); Company Brief at 274 (gas)). The Company maintains that the Department previously has found that there is a strong likelihood that the 2003 Global Research Analysts Settlement ("2003 Settlement")[211] has mitigated systematic bias in overly optimistic stock recommendations and that analyst growth rate forecasts are still not subject to overly optimistic projections tending to overstate the required ROE (Company Brief at 341 (electric); Company Brief at 275 (gas), citing D.P.U. 22-22, at 386; D.P.U. 19-120, at 374). The Company also contends that the Department

[211] The 2003 Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts. D.P.U. 19-120, at 370 n.183.

has found that EPS growth rates provide a more statistically reliable measure of growth than DPS or BVPS (Company Brief at 339 (electric); Company Brief at 273-274 (gas), citing D.P.U. 19-120, at 373; D.P.U. 18-150, at 472). Moreover, the Company asserts that its analysis demonstrates that projected EPS are the only growth rates that have a statistically significant relationship to stock valuations for utilities (Company Brief at 339 (electric); Company Brief at 273 (gas), citing Exh. Unitil-DWD-Rebuttal at 42-43).

(B) CAPM and Empirical CAPM

Unitil argues that the Attorney General's MRP relies on surveys and studies that are opaque, biased, and unlikely to reflect the future expectations of investors (Company Brief at 341-342 (electric); Company Brief at 276 (gas), citing Exh. Unitil-DWD-Rebuttal at 46-56). In addition, the Company asserts that some of the Attorney General's MRP sources are subject to disclaimers that they are not for regulatory purposes and do not constitute substantive research or analysis (Company Brief at 342 (electric); Company Brief at 276 (gas)). Further, Unitil claims that MRP surveys have poor predictive power of actual stock returns because they tend to reflect the recent past rather than accurate forecasts of the future (Company Brief at 342 (electric); Company Brief at 276 (gas), citing Exh. Unitil-DWD-Rebuttal at 54-55). The Company also contends that the Department previously has found that the surveys used by the Attorney General for her CAPM are based on limited sample data and, therefore, the Department has placed little weight on their results (Company Brief at 342 (electric); Company Brief at 276 (gas), citing D.P.U. 19-120, at 385; D.P.U. 18-150, at 484).

Further, Unitil maintains that, contrary to the Attorney General's position, the Company's MRP is not vastly overstated and is consistent with historical returns (Company Brief at 342 (electric); Company Brief at 276-277 (gas), citing Exh. Unitil-DWD-Rebuttal at 85). The Company contends that U.S. nominal GDP growth has not been demonstrated to be the primary driver of stock valuations and, contrary to the Attorney General's position, market returns are not correlated with GDP growth (Company Brief at 342 (electric); Company Brief at 277 (gas), citing Exh. Unitil-DWD-Rebuttal at 85).

Finally, the Company argues that the empirical CAPM was developed based on an extensive body of empirical research performed by well-respected finance scholars (Company Brief at 343 (electric); Company Brief at 277 (gas), citing Exhs. Unitil-DWD-1, at 42-43; Unitil-DWD-Rebuttal at 57-59). The Company claims that the Attorney General acknowledges that empirical studies show that the risk-return relationship between beta and stock returns is flatter than what is predicted by the traditional CAPM (Company Brief at 343 (electric); Company Brief at 277 (gas), citing Exh. AG-JRW-1, at 110).

(C) PRPM and MRPM

The Company argues that the Department should reject the Attorney General's objections to the ERPs used in the PRPM and MRPM for the same reasons that the Department should reject the Attorney General's objections to the MRPs used in the CAPM (Company Brief at 343 (electric); Company Brief at 277 (gas)). Further, Unitil contends that the Department has viewed the risk premium approach as a supplemental approach in determining an ROE (Company Brief at 343 (electric); Company Brief at 277 (gas), citing D.P.U. 07-71, at 137).

(D) Adjustments

Unitil argues that the size of an enterprise materially affects the level of its business risk because smaller companies are less capable of coping with significant events that affect sales, revenues, and earnings (Company Brief at 332 (electric), citing Exh. Unitil-DWD-1, at 51-53 (electric); Company Brief at 265 (gas), citing Exh. Unitil-DWD-1, at 51-53 (gas)). The Company contends that the market capitalization of the Electric Proxy Group is 211.2 times larger than Unitil and that the market capitalization of the Gas Proxy Group is 42.8 times larger than Unitil (Company Brief at 332 (electric), citing Exh. Unitil-DWD-1, at 56 (electric); Company Brief at 265 (gas), citing Exh. Unitil-DWD-1, at 55-56 (gas)). Therefore, the Company asserts that the cost of equity must reflect the additional risk to investors (Company Brief at 332 (electric), citing Exh. Unitil-DWD-1, at 55-56 (electric); Company Brief at 265 (gas), citing Exh. Unitil-DWD-1, at 55-56 (gas)).

Additionally, Unitil claims that an upward credit risk adjustment is necessary to reflect the difference between Company's long-term issuer ratings and the average long-term issuer rating for the Gas Proxy Group (Company Brief at 266 (gas), citing Exh. Unitil-DWD-1, at 57-58 (gas)). The Company asserts that the credit risk adjustment should be an increase of 0.18 percent to its proposed range of ROEs for the gas division (Company Brief at 266 (gas), citing Exhs. Unitil-DWD-1, at 57-58 (gas); Unitil-DWD-Rebuttal at 4).

Finally, Unitil contends that there are costs associated with an issuance of new equity stocks that result in the Company receiving fewer dollars than what is raised in an offering (Company Brief at 332 (electric), citing Exh. Unitil-DWD-1, at 57 (electric); Company Brief at 266 (gas), citing Exh. Unitil-DWD-1, at 58 (gas)). Unitil argues that flotation cost adjustments increasing the ROE by 0.46 percent for the electric division and 0.45 percent for the gas division are necessary to account for the issuance costs (Company Brief at 333 (electric); Company Brief at 266 (gas)).

ii. Investment Risks

Unitil argues that in determining the authorized ROE from the model results, the Department must consider the impact on the Company's risk of the stay-out provision of the proposed PBR plans and regulatory uncertainty in the electric and gas industries (Company Brief at 333-334 (electric); Company Brief at 266-267 (gas)). Specifically, Unitil contends that the five-year stay-out provision increases the Company's risk because long-term capital costs have the potential to increase during the stay-out period (Company Brief at 333 (electric); Company Brief at 266-267 (gas)). The Company also claims that Massachusetts EDCs face regulatory uncertainty driven by grid modernization and the energy transition (Company Brief at 333 (electric), citing Exh. Unitil-RBH-1, at 15; Tr. 10, at 1169-1170). Further, Unitil asserts that there is regulatory uncertainty for the gas industry in relation to the Department's decision in D.P.U. 20-80-B that, the Company claims, prompted a negative outlook on investment in gas distribution companies in Massachusetts by Guggenheim Securities LLC (Company Brief at 267 (gas), citing Exh. Unitil-1; Tr. 10, at 1174). The Company argues that the Department must establish Unitil's ROE at the higher end of the reasonable range to reflect these risks (Company Brief at 334 (electric); Company Brief at 267 (gas)).

iii. Market Conditions and Trends in Authorized ROEs

Unitil disputes the Attorney General's portrayal of capital market conditions and argues that she attempts to minimize the duration of current high capital costs (Company Brief at 345-346 (electric); Company Brief at 279-281 (gas)). Further, the Company contends that because of the increase in interest rates since the Company's last base distribution rate increase in 2020, the allowed ROE should be higher than the 9.70 percent ROE agreed to by the Attorney

General and approved by the Department in D.P.U. 19-130 and D.P.U. 19-131 (Company Brief at 346 (electric); Company Brief at 281 (gas)). Additionally, Unitil asserts that the Federal Reserve is not likely to significantly reduce interest rates in the near future if inflation stays at 2.40 percent over the next five years (Company Brief at 346 (electric); Company Brief at 280 (gas)). Regarding the Attorney General's position that authorized ROEs did not decline in line with interest rates, the Company contends that although there is not a one-to-one correlation between an increase in long-debt interest rates and the cost of equity, as interest rates increase the cost of equity also increases (Company Brief at 346 (electric); Company Brief at 281 (gas), citing D.P.U. 22-22, at 399). For these reasons, the Company claims that the Attorney General's skewed portrayal of capital market conditions and recent authorized ROEs should be rejected (Company Brief at 345 (electric); Company Brief at 280 (gas)).

iv. Required ROE

Unitil argues that its ROE should be set at the higher end of the reasonable range because it has contained operating costs while providing exemplary customer service (Company Brief at 334 (electric), citing Exh. Unitil-RBH-1, at 65 (electric); Company Brief at 268 (gas), citing Exh. Unitil-DJH-1, at 50 (gas)). Nonetheless, Unitil asserts that it has chosen to maintain its initially proposed ROEs of 10.50 for the electric division and 10.75 percent for the gas division because of its customers' energy burdens and despite the record evidence, which the Company claims demonstrates that the cost of equity increased during these proceedings (Company Brief at 334 (electric); Company Brief at 285 (gas)). Further, Unitil contends that the Department must authorize ROEs that account for the regulatory uncertainty associated with the clean energy transition and grid modernization as well as the Company's risk of incurring significant cost increases during the five-year PBR plans (Company Brief at 333-334 (electric); Company Brief at 266-267 (gas)).

Finally, Unitil argues that the Attorney General failed to provide record evidence to support her allegation that the Company's rates are the result of management inefficiency (Company Reply Brief at 2-3). The Company maintains that the Attorney General's recommended ROEs would adversely impact Unitil's customers because they would: (1) result in more frequent base distribution rate proceedings and higher costs; (2) provide inadequate capital to support the clean energy transition; and (3) likely result in negative reactions from the credit ratings agencies and the financial community (Company Reply Brief at 11-12).

4. Analysis and Findings

a. Introduction

When setting a reasonable range of ROEs and then determining the allowed ROE, the Department is guided by the standard set forth in Hope and Bluefield. The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. Bluefield at 692-693; Hope at 603, 605. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692.

The use of empirical analyses in this context is not an exact science. D.P.U. 17-170, at 305; D.P.U. 15-155, at 377; see also Southern Bell Telephone and Telegraph Company v. Louisiana Public Utility Commission, 239 La. 175, 225 (1960) (ascertainment of a fair return in a given case is a matter incapable of exact mathematical demonstration); United Railways & Electric Company of Baltimore v. West, 280 U.S. 234, 250 (1930) (what will constitute a fair return is not capable of exact mathematical demonstration). Conducting a model-based ROE analysis requires the analyst to make several subjective judgments. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

While the results of analytical models are useful, the Department must ultimately use our own judgment of the evidence to determine an appropriate ROE. We must apply the Department's considerable judgment and expertise to the record evidence and arguments to determine the appropriate use of the empirical results. Our task is not a mechanical or model-driven exercise. D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison, 375 Mass. 1, 15 ("experience has shown that, in making a determination as elusive as estimating the cost of equity capital, 'mathematical formulas and rules of thumb are obsolete,'" citing A.J.G. Priest, Principles of Public Utility Regulation 196 (1969)).[212]

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[212] As the Department stated in New England Telephone and Telegraph Company, D.P.U. 17441, at 9 (1973):

> Advances in data gathering and statistical theory have yet to achieve precise prediction of future events or elimination of the bias of the witnesses in their selection of data. Thus, there is no irrefutable testimony, no witness who has not made significant subjective judgments along the way to his conclusion, and no number that emerges from the welter of evidence as an indisputable "cost" of equity.

b. ROE Estimation Models

i. DCF Model

(A) EPS and DPS Growth Rates

Unitil and the Attorney General both rely on the DCF model, a valuation method commonly used in the field of finance, which holds that the present value of an asset is equal to the discounted value of its expected future cash flows, discounted by the investor at a required rate of return (Exhs. Unitil-DWD-1, at 4, 23-24 (electric); Unitil-DWD-1, at 4, 23-24 (gas); AG-JRW-1, at 3-5, 41). This required rate of return reflects both the time value of money (i.e., the concept that an amount of money received in the future is not worth as much as an equal amount received today) and the perceived riskiness of the expected future cash flows (Exh. AG-JRW-1, at 41, 44). The parties disagree on the appropriate input for the long-term growth rate in the model, proposing either: (1) the proxy companies' projected three-to-five year EPS growth rates; or (2) a composite growth rate based on the proxy companies' historical and projected EPS, DPS, BVPS, and sustainable growth rates (Exhs. Unitil-DWD-Rebuttal at 24-44, 70-72; Unitil-DWD-1, at 25 (electric); Unitil-DWD-1, at 25 (gas); AG-JRW-Surrebuttal-1, at 3, 12-19).

The appropriate growth rate for a DCF analysis is often controversial. D.P.U. 22-22, at 386; D.P.U. 15-155, at 365. Previously, the Department has found that a variety of quantitative factors, including growth in EPS, DPS, and BVPS, should be considered when determining an appropriate growth rate. D.P.U. 07-71, at 136; D.T.E. 02-24/25, at 227; D.P.U. 96-50 (Phase I) at 120; D.P.U. 93-60, at 51; D.P.U. 92-250, at 147. In two more recent cases, however, the Department has found that EPS growth rates provide a more statistically reliable measure of growth than DPS or BVPS based on evidence in those proceedings that utility price-earnings ratios were greater than historical averages in recent years. D.P.U. 19-120, at 373; D.P.U. 18-150, at 472. In addition, the Department previously has considered whether the 2003 Settlement addressed causes of upward bias in EPS growth rate forecasts. D.P.U. 20-120, at 419-420; D.P.U. 19-120, at 374. We consider the Department's prior findings in our evaluation of the record evidence.

The starting point of our analysis on the appropriate growth rate for the DCF model must be the theoretical assumptions of the model itself. Dividends, rather than earnings, constitute the source of value in the DCF model because dividends are the only cash value received by investors (Exhs. Unitil-DWD-1, at 23 (electric); Unitil-DWD-1, at 24 (gas); AG-JRW-1, at 47; DPU-AG 2-10 (electric); DPU 34-6, Att. 1, at 5 (electric); DPU-AG 1-10 (gas); DPU 29-6, Att. 1, at 5 (gas)). The DCF model assumes that the firm subject to valuation analysis is in the mature stage of its business life cycle, often called the "steady state," and that its dividends and earnings grow at the same rate in perpetuity (Exhs. AG-JRW-1, at 43-44, 50; Unitil-DWD-Rebuttal at 35; DPU-AG 2-4 (electric); DPU-AG 1-4 (gas); Tr. 7, at 741-742). Further, the record demonstrates that companies in the mature stage of their business life cycle pursue stable dividend policies that align dividend growth with the company's internal long-term growth expectations (Tr. 7, at 734-741; Tr. 10, at 1057). In other words, mature companies like the utilities in the proxy groups do not significantly increase or cut dividends in response to periods of unusually high or low earnings because of the signals that would send to the market (Tr. 7, at 734-741; Tr. 10, at 1057). Unlike DPS growth rates that companies keep stable over time, EPS growth rates reflect current firm-specific and economic conditions that may not reflect reasonable long-term growth expectations, making three-to-five-year projected DPS growth a more appropriate proxy for growth in perpetuity (Exh. AG-JRW-1, at 52, Figure 11 (showing volatility of actual EPS growth for electric and gas utilities from 1985 to 2022); Tr. 7, at 734-741, 745; Tr. 10, at 1057). Also, we are not persuaded that investors do not rely on DPS growth rates simply based on the number of investment research firms that publish DPS estimates because DPS growth rates of mature companies are predictable and easily forecasted (Exh. Unitil-DWD-Rebuttal at 36; Tr. 10, at 1057). In light of these findings, we conclude that the use of DPS growth rates in the DCF model is consistent with the theoretical assumptions of the DCF model and three-to-five-year DPS growth rates are a better input for long-term expectations of growth than three-to-five-year EPS growth rates (Exhs. AG-JRW-1, at 47, 52, Figure 11; DPU-AG 2-10 (electric); DPU 34-6, Att. 1, at 5 (electric); DPU-AG 1-10 (gas); DPU 29-6, Att. 1, at 5 (gas); Tr. 7, at 734-741; Tr. 10, at 1057).

Next, we have evaluated Unitil's analysis testing the statistical relationship between trailing price-earnings ratios and historical and projected EPS, DPS, and BVPS growth rates (Exh. Unitil-DWD-Rebuttal at 30-43; Tr. 7, at 741-744, 761-763). Based on the Department's expertise in statistical methods and techniques, we find that the Company's analysis relies on regression results with very low coefficients of determination (i.e., R-squared values), which indicates that the models have low explanatory value (Exhs. Unitil-DWD-Rebuttal at 42; Unitil-DWD-Rebuttal-2, Sch. 4, at 1-4). Additionally, the Company introduces a degree of circularity by using the trailing price-earnings ratio as the dependent variable and the projected earnings growth rate as the independent variable to establish the relationship between earnings and price (Exh. Unitil-DWD-Rebuttal-2, Sch. 4, at 1-4). Therefore, we are not persuaded by

Unitil's analysis that EPS is more statistically reliable than DPS or BVPS (Exh. Unitil-DWD-Rebuttal-2, Sch. 4, at 1-4).

Turning to the issue of upward bias in EPS forecasts, the Department first found in 2019 that there is a strong likelihood that the 2003 Settlement mitigated systematic bias in overly optimistic stock recommendations based on the terms of the agreement, including enforcement and structural reforms. D.P.U. 19-120, at 374. The next year, the Department dismissed claims that the systematic bias in EPS had persisted after the 2003 Settlement based on two studies published in 2010 that found the forecast bias had declined significantly and analysts' forecasts generally coincided with actual earnings in the period following the 2003 Settlement. D.P.U. 20-120, at 419-420.

In the instant proceedings, the Attorney General provided a new study comparing EPS growth rate estimates for electric and gas distribution companies to the actual, or realized, EPS growth rates over the period 1985 to 2022 (Exhs. AG-JRW-1, at 51-52, AG-JRW-Surrebuttal-1, at 18-19). Over the entire period, the mean forecasted EPS growth rate was more than 200 basis points above the actual EPS growth rate (Exhs. AG-JRW-1, at 52; AG-JRW-Surrebuttal-1, at 18). The Attorney General's study shows that there likely is less disparity between forecasted and actual EPS growth rates in the period after the 2003 Settlement compared with the years before; nevertheless, the study shows that, with the exception of short periods around 2007 and 2018, forecasted EPS growth rates remain consistently higher than the actual EPS growth rates after 2003 (Exh. AG-JRW-1, at 52). Since the Attorney General's study analyzes a significantly larger period of time after the 2003 Settlement than the 2010 studies considered in D.P.U. 20-120, we find that the Attorney General's study is more persuasive and that systemic bias in analysts' EPS growth estimates likely persists (Exh. AG-JRW-1, at 52). We take the presence of systemically biased EPS growth estimates in the parties' DCF results into consideration in our evaluation of the reasonable range below.

(B) Future Proceedings

Consistent with the theoretical assumptions of the DCF model and the record evidence, we have determined that DPS growth rates are a better input for long-term growth expectations than EPS growth rates. Therefore, we direct all electric and gas companies that submit an ROE analysis with their future base distribution rate proceedings to include a separate DCF model result in their initial filings that includes only DPS growth rates for the proxy companies as the expected long-term growth rate in addition to other ROE estimation models that, in their judgment, provide a reliable estimate of the cost of equity. Furthermore, we encourage the Attorney General to provide a discernible derivation of the long-term growth rate used in her DCF model in future proceedings to make her analysis transparent and accessible, as well as to assist the Department in our review of her model.

ii. CAPM

The CAPM is a well-known risk premium model that assumes that investors require an excess return for investing in risky assets, such as stocks, above the yields on risk-free assets such as U.S. Treasury Bonds (Exh. AG-JRW-1, at 59). To estimate the cost of equity, the CAPM requires the following inputs: (1) an expected return on the overall equity market; (2) a risk-free rate of interest (usually using a long-term U.S. Treasury Bond); (3) an expected equity or market risk premium (i.e., the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks); and (4) a beta (i.e., the systematic risk of a security measured by the covariance between the price of a stock and the price of the market index) (Exhs. Unitil-DWD-1, at 40-41 (electric); Unitil-DWD-1, at 41 (gas); AG-JRW-1, at 59-60).

Unitil and the Attorney General both ask the Department to rely on the CAPM to determine Unitil's authorized ROE, but the parties have provided substantially different CAPM results driven by differing opinions on the appropriate measure of the MRP (Exhs. Unitil-DWD-Rebuttal at 4; AG-JRW-1, at 65 ("[the MRP] is very difficult to measure and is one of the great mysteries in finance"); AG-JRW-Surrebuttal-1, at 28-35). After consideration of the findings provided below, we conclude that the Company's CAPM and empirical CAPM results suffer from several fatal flaws and, therefore, we do not rely on the Company's CAPM or empirical CAPM results in our determination of the reasonable range and Unitil's allowed ROE. We also find that the Attorney General's reliance on geometric averages to determine the MRP in her CAPM model results in a slightly understated ROE estimate, and we consider this finding in determining the reasonable range and authorized ROE below.

After review, we find that substantial record evidence supports each of the following findings regarding two of Unitil's MRPs based on historical data. First, based on the Department's expertise in statistical methods and techniques, we find that MRP Measure 2 relies upon a regression analysis with statistically de minimis explanatory value (Exh. Unitil-DWD-Rebuttal-2, MRP ERP WP; Tr. 7, at 680-686, 701-702). The coefficient of determination (R-squared) of the Company's regression is 0.019, which indicates that the model explains less than two percent of dependent variables (remainder is either explained by omitted variables or is random noise) (Exh. Unitil-DWD-Rebuttal-2, MRP ERP WP; Tr. 7, at 680-686, 701-702).

Second, the Department finds that the Company has provided insufficient record evidence for us to conclude that financial analysts rely on the PRPM to make investment decisions or that the PRPM has been widely accepted by regulatory commissions to determine an authorized ROE (Exhs. Unitil-DWD-1, at 27-29 (electric); Unitil-DWD-1, at 27-29 (gas); Unitil-DWD-Rebuttal at 82 DPU 21-11, Att. 1 (electric); DPU 49-11 (electric); DPU 15-11, Att. 1 (gas); DPU 38-11 (gas); AG-JRW-1, at 86). Accordingly, we decline to accept Unitil's PRPM results in our determination of the Company's authorized ROE.

Further, we find that substantial record evidence supports a finding that Unitil calculates MRP Measure 4, MRP Measure 5, and MRP Measure 6 using unrealistic assumptions of future earnings growth and stock market returns (Exh. AG-JRW-1, at 89-98). First, we find that MRP Measure 4's estimated annual market return of 15.51 percent based on Value Line's three-to-five-year median appreciation potential is an unrealistic expectation for a long-term market return when compared to the compounded annual return in the U.S. stock market between 1928-2022 of 9.64 percent (Exhs. Unitil-DWD-Rebuttal-2, Sch. 1, at 36-37, Sch. 2, at 26-27; AG-JRW-1, at 91). We find it unreasonable to expect the market will sustain a return that is 5.87 percent above the market's actual return over the last century and, as a result, we find that the Attorney General's research and testimony concluding Value Line's predicted stock market returns are "extremely overoptimistic" are credible (Exh. AG-JRW-1, at 94). As such, we find that the Company's use of MRP Measure 4 in its analysis results in an unreliable and overstated estimation of the ROE in this proceeding.

With regard to MRP Measures 5 and 6, the Department has reviewed the record and finds that these MRPs are based on insufficiently supported and flawed assumptions that render them unreliable for purposes of determining the reasonable range and Unitil's authorized ROE. First, for the companies in the S&P 500 Index that do not pay dividends, Unitil's calculation of the market return assumes that projected three-to-five-year EPS growth rates are an appropriate proxy for the future gain realized on the price appreciation of those companies' stocks (Exhs. Unitil-DWD-3, MRP WP2, MRP WP3 (electric); Unitil-DWD-Rebuttal-2, MRP WP2, MRP WP3; Unitil-DWD-3, MRP WP2, MRP WP3 (gas); Tr. 7, at 748-750). Accordingly, for these companies, Unitil is not performing the widely used and accepted DCF calculation at all but rather an adaptation of it based on assumptions that the Company has not sufficiently supported with record evidence. As we found above, three-to-five-year EPS growth rate estimates are volatile and reflect current economic conditions (Exh. AG-JRW-1, at 52, Figure 11 (showing volatility of actual EPS growth for electric and gas utilities from 1985 to 2022); Tr. 7, at 734-741, 745; Tr. 10, at 1057). Therefore, we reject the Company's position and cannot find that the record supports the assumption that three-to-five-year EPS growth rates approximate the gain that will be realized on the price appreciation of stock in perpetuity (Exh. Unitil-DWD-Rebuttal at 50 ("equity is assumed to be outstanding in perpetuity")).

Second, the S&P 500 Index includes firms that are in the growth stage of the business life cycle (Tr. 7, at 746). Companies that are in the growth stage of their business life cycle have a high growth rate in EPS (Exh. AG-JRW-1, at 43; Tr. 7, at 752). Eventually such companies will transition to the mature stage (i.e., steady state) of the business life cycle where earnings growth will stabilize, which is why a multistage DCF analysis is appropriate for such companies (Exh. AG-JRW-1, at 43). Accordingly, the Department finds that the Company overestimates the long-term market return by assuming the S&P 500 Index companies in the growth stage will maintain a constant, high rate of EPS growth in perpetuity (Exh. AG-JRW-1, at 43; Tr. 7, at 752). Additionally, as discussed above, the DCF model estimates the expected return based upon the long-term growth in dividends. Therefore, even a multistage DCF analysis on the S&P 500 Index companies that pay dividends could overstate the market return if the analysis considers only projected EPS growth rates, which are volatile and upwardly biased. Similar to the Company's estimated return for the Value Line companies, we find that Unitil's estimated returns for the S&P 500 Index of 14.21 percent and 18.21 percent are unrealistic expectations for a long-term market return when compared to the compounded annual return in the U.S. stock market between 1928 and 2022 of 9.64 percent (Exhs. Unitil-DWD-Rebuttal-2, Sch. 1, at 36-37, Sch. 2, at 26-27; AG-JRW-1, at 91). Based on these findings, the Department concludes that the Company's use of MRP Measure 5 and MRP Measure 6 in the CAPM results in an unreliable and overstated ROE estimate.

Finally, the Department has reviewed the record evidence on the Attorney General's proposed CAPM results. Previously, the Department has found that the Attorney General's approach of reviewing various MRP studies and surveys of financial analysts, academics, and companies is a better approach to developing an MRP than the Company's approach. D.P.U. 15-80/D.P.U. 15-81, at 281-282. We reaffirm that finding. Nevertheless, the record shows that the Attorney General's reliance on geometric mean returns in the development of her MRP results in a slightly understated ROE estimate. Specifically, the record shows that arithmetic mean return rates are appropriate for cost of capital purposes, not geometric mean return rates (Exh. Unitil-DWD-Rebuttal at 74-79). When returns are not serially correlated, as is the case here, the arithmetic mean represents the best forecast of future return in any randomly selected future year (Exh. Unitil-DWD-Rebuttal at 74). Among other MRP sources, including eight ex-ante models and four surveys of financial professionals, the Attorney General relies on both arithmetic and geometric mean return rates to determine her MRP (Exhs. JRW-6, at 6; DPU-AG 2-12, Att. 1 (electric), DPU-AG 1-12, Att. 1 (gas)). Therefore, the Department finds that the Attorney General's partial reliance on geometric mean return rates results in a slightly understated ROE and will consider this limitation in the Attorney General's CAPM results in determining the reasonable range below.

iii. Empirical CAPM

The Department previously has rejected the empirical CAPM. D.P.U. 22-22, at 392; D.P.U. 10-70, at 271. We are not persuaded to deviate from our prior treatment of the empirical CAPM results because the Company and the Attorney General provide contradictory expert testimony on the validity of the empirical CAPM, the Company was unable to indicate whether investors consider the empirical CAPM more reliable than the traditional CAPM, and only a small number of regulatory jurisdictions have relied on the empirical CAPM for rate setting purposes (Exhs. DPU 21-10 (electric); AG 2-11 (electric); DPU 15-10 (gas); AG 2-11 (gas)). D.P.U. 22-22, at 392. Furthermore, Unitil's empirical CAPM results rely on the same flawed MRPs that we analyzed and rejected above (see Section XI.D.4.b.ii above). Therefore, the Department finds that the Company's empirical CAPM results are unreliable estimates of Unitil's cost of equity (Exhs. Unitil-DWD-3, Sch. 5, at 1 (electric); Unitil-DWD-3, Sch. 5, at 1 (gas); Unitil-DWD-Rebuttal-2, Sch. 1, at 36, Sch. 2, at 26).

iv. PRPM and MRPM

The Department has repeatedly found that the bond-yield plus risk premium model can overstate the amount of company-specific risk and, therefore, the cost of equity. D.P.U. 17-05-H at 11-12; D.P.U. 17-05, at 701-702; D.P.U. 10-114, at 322; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has long criticized the use of long-term corporate or public utility bond yields because these instruments may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, the bond-yield plus risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183.

For the reasons stated above regarding MRP Measure 3, we find there is insufficient evidence to determine that the PRPM is widely accepted by investors or regulatory commissions and we do not rely on the PRPM to determine Unitil's ROE (see Section XI.D.4.b.ii). Additionally, the Company uses the Blue Chip Financial Forecasts consensus forecast of the 30-year U.S. Treasury yield for the risk-free rate (Exhs. Unitil-DWD-1, at 44 (electric); Unitil-DWD-1, at 44 (gas); Unitil-DWD-Rebuttal-2, at Sch. 1, at 36-37, Sch. 2, at 26-27). The Department has found that because the bond-yield risk premium model is not a forward-looking approach and is, instead, based on current market conditions, current U.S. Treasury bond yields are the appropriate measure of the risk-free rate in the bond-yield risk premium model. D.P.U. 17-05-H at 12, citing D.P.U. 17-05, at 702-703; D.P.U. 13-75, at 319; D.P.U. 12-25, at 433. Based on the foregoing reasons, the Department will not rely on the results of the PRPM in our determination of the reasonable range and Unitil's allowed ROE.

In addition, the Department finds that the MRPM has the same deficiencies found regarding the Company's CAPM analysis because ERP Measure 1 and ERP Measure 2 are composed of the same approaches used in its CAPM analysis (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 23, 29, Sch. 2, at 13, 19; see Section XI.D.4.b.ii). Regarding ERP Measure 3, we also find that an ERP based on allowed ROEs from fully litigated base distribution rate cases as the independent variable for the regression is inherently circular and, thus, a flawed approach to estimating the cost of equity (Exhs. Unitil-DWD-1, at 39 (electric); Unitil-DWD-1, at 38-39 (gas)). Additionally, the Company uses risk-free rates of 6.12 percent and 5.94 percent, which are adjusted prospective corporate bond yields, an input that the Department consistently has rejected (Exh. Unitil-DWD-Rebuttal-2, Sch. 1, at 25, Sch. 2, at 15). D.P.U. 22-22, at 394 citing D.P.U. 17-05-H at 12, D.P.U. 17-05, at 702-703; D.P.U. 13-75, at 319; D.P.U. 12-25, at 433. Consistent with these findings and Department precedent, the Department finds that the Company's MRPM is the product of a flawed analysis that overstates the cost of equity and, therefore, we do not rely on the results of the MRPM to determine the reasonable range and Unitil's allowed ROE.

c. Company Adjustments

As discussed above, Unitil proposes that the Department consider adjustments to the ROE model results to account for the Company's size, credit rating, and flotation costs. For the reasons set forth below, we conclude that none of these proposed adjustments is appropriate.

Regarding Unitil's relative size, the Department generally agrees with Unitil's proposition that the size of a firm materially affects the level of its business risk (Exhs. Unitil-DWD-1, at 51-53 (electric); Unitil-DWD-1, at 51-53 (gas)). Nevertheless, the record evidence demonstrates that the credit ratings determinations by Moody's and S&P Ratings for the Company and Unitil Corporation consider the Company's size relative to its peers in the industry and, according to the Company, bond and credit ratings are a proxy for a firm's combined business and financial risks (Exhs. Unitil-DWD-1, at 12 (electric); Unitil-DWD-1, at 12 (gas); AG-JRW-1, at 7; see, e.g., AG 1-11, Att. 3, at 2, Att. 4, at 2, Att. 5, at 2; Att. 6, at 1, Att. 9, at 1; Att. 10, at 1). Therefore, the Department denies Unitil's proposed size adjustment because the Company's credit ratings are the same as the average for the Electric Proxy Group and AG Electric Proxy Group and Unitil's credit ratings already account for the Company's size relative to its peers in the industry (Exhs. Unitil-DWD-1, at 12 (electric); Unitil-DWD-1, at 12 (gas); AG-JRW-1, at 7; see, e.g., AG 1-11, Att. 3, at 2, Att. 4, at 2, Att. 5, at 2; Att. 6, at 1, Att. 9, at 1; Att. 10, at 1).

Unitil's updated analysis proposes no credit adjustment for the electric division and a 0.18 percent credit risk adjustment for the gas division (Exh. Unitil-DWD-Rebuttal at 4). Above, we found that the Gas Proxy Group was too small to be reliable and concluded that it was reasonable and appropriate to determine a single ROE for Unitil based on the results of the Electric Proxy Group and AG Electric Proxy Group. Since Unitil's credit ratings and the average credit ratings of the Electric Proxy Group and AG Electric Proxy Group are the same, the Department denies Unitil's proposed credit risk adjustment (Exhs. Unitil-DWD-Rebuttal at 4; AG-JRW-1, at 7).

Turning to the Company's proposed adjustments for flotation costs, the Department has consistently rejected issuance cost adjustments for purposes of determining an allowed ROE. D.P.U. 22-22, at 387; D.P.U. 10-70, at 259; D.P.U. 90-121, at 180 ("[t]he use of a flotation cost adjustment to the cost of equity is not acceptable"). The Department has previously found that investors already consider issuance costs in their decision to purchase a stock at a given price. D.P.U. 22-22, at 387; D.P.U. 90-121, at 180, citing D.P.U. 88-67 (Phase I) at 193; D.P.U. 87-260, at 105-106; D.P.U. 86-280-A at 112; D.P.U. 85-137, at 100. The Department reaffirms these findings and finds that Unitil has failed to present any new evidence or arguments to justify a departure from long-standing precedent. Therefore, the Department denies Unitil's proposed adjustment for flotation costs.

d. Reasonable Range

Based on our precedent and analysis of the records of these proceedings, the Department has: (1) accepted the Electric Proxy Group and AG Electric Proxy Group as sufficiently comparable to Unitil to consider those model results in determining the allowed ROE; (2) rejected Unitil's Gas Proxy Group, Electric Non-Price Regulated Proxy Group, and Gas Non-Price Regulated Proxy Group; (3) found it is appropriate and reasonable to determine a single allowed ROE for both Unitil's electric and gas divisions based on the ROE model results of the Electric Proxy Group and AG Electric Proxy Group; (4) found that the use of DPS growth rates is consistent with the theoretical assumptions of the DCF Model; (5) found that it is likely that projected EPS growth rates are upwardly biased and overly optimistic; (6) rejected Unitil's CAPM and empirical CAPM results; (7) found that the Attorney General's CAPM results slightly understate the cost of equity; (8) rejected Unitil's PRPM and MRPM results; and (9) rejected adjustments to the model results for size, credit risk, and flotation costs. In our judgment, based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that 8.85 percent to 9.95 percent is a reasonable range of ROEs for Unitil in this proceeding. We determine that: (1) setting the low-end of the reasonable range at 8.85 percent is consistent with our finding that the Attorney General's CAPM results slightly understates the cost of equity; and (2) setting the high-end of the reasonable range at 9.95 percent is consistent with our finding that DCF results that rely on EPS growth rates likely overstates the cost of equity (see Sections XI.D.4.b.i. and XI.d.4.b.ii. above).

e. Market Conditions

In determining an allowed ROE within the reasonable range, the Department has previously considered evidence of the impact that changing market conditions will have on the quantitative ROE estimates. D.P.U. 17-05-H, at 15-16; D.P.U. 20-120, at 434-435; D.P.U. 19-120, at 357-362; D.P.U. 17-170, at 280-281. Projecting future market trends, whether interest rates, dividends and earnings growth, or GDP growth, is difficult through surveys and modeling alike, and the Department will reject proposals to adjust cost of equity estimates without compelling evidence. D.P.U. 20-120, at 434-435; D.P.U. 17-170, at 280.

In this case, the Company provides testimony that interest rates and inflation continue to have an upward impact on capital costs, and the Attorney General presents testimony that an inverted yield curve suggests that the economy may enter into a recession and, as a result, lower interest rates are likely to follow (Exhs. Unitil-DWD-Rebuttal at 2, 5, 8; AG-JRW-1, at 16-18). After review, the Department finds that neither party has presented compelling evidence of projected market trends to warrant an adjustment to Unitil's authorized ROE based on current market data. See D.P.U. 20-120, at 417 (declining to accept interpretation of model results based on speculative testimony on future market conditions); c.f., D.P.U. 22-22, at 398-399 (allowing an authorized ROE in the upper half of the reasonable range based on the Federal Reserve Board's statements that it would institute further rate increases through the year following the Department's Order).

f. Investment Risk

As discussed above, Unitil contends that the Department should consider its increased investment risk relative to the proxy groups caused by the stay-out provision of the PBR plans and the uncertainty regarding the clean energy transition (Company Brief at 334 (electric); Company Brief at 267 (gas)). Similarly, the Attorney General states that Unitil's capital structure relative to the proxy groups decreases the Company's financial risk and, thus, its investment risk (Exh. AG-JRW-1, at 33).

In our decision on Unitil's allowed ROE below, we have also considered Unitil's position that its investment risk is increased by the stay-out provision of the Company's approved PBR plans as well as policy and legislative changes designed to enable the clean energy transition. In the past, the Department has found that a PBR plan's more timely and flexible cost recovery serves to reduce a company's risks while a stay-out provision as part of a PBR plan may increase a company's risks in meeting its financial requirements. D.P.U. 22-22, at 403; D.P.U. 20-120, at 431-432; D.P.U. 19-120, at 405-405. Additionally, the Department previously has found that the purported risks imposed by Massachusetts policy and legislative changes designed to enable the clean energy transition would affect a company to a lesser degree in the context of a five-year stay-out provision. D.P.U. 20-120, at 433.

The Department has established in this Order separate five-year PBR plans specific to the Company's electric and gas divisions and has not previously increased a company's ROE for a five-year stay-out provision. Compare D.P.U. 22-22, at 403 (allowing an ROE near the midpoint of the reasonable range under a five-year PBR plan) and D.P.U. 20-120, at 431-432 (allowing an ROE near the midpoint of the reasonable range under a five-year PBR plan) with D.P.U. 19-120, at 405-405 (finding a ten-year PBR plan significantly increased risk). Consistent with our prior decisions, therefore, Unitil's ROE should not be increased because of its proposed PBR plans. Second, the records do not support a determination that an adjustment to the authorized ROE to account for Unitil's specific investment risk is appropriate. As stated by the Company, bond and credit ratings are a suitable proxy for Unitil's combined business and financial risks to equity investors (Exhs. Unitil-DWD-1, at 12 (electric); Unitil-DWD-1, at 12 (gas)). As we found with respect to Unitil's size, above, the credit rating agencies account for Unitil's financial risk and the operating environment in Massachusetts in their rating determinations (see, e.g., Exh. AG 1-11, Att. 1, at 4; Att. 3, at 5, Att. 5, at 4, Att. 6, at 1, 6-7, Att. 10, at 2; Tr. 7, at 715). As discussed above, Unitil's credit ratings are the same as the Electric Proxy Group and AG Electric Proxy Group (see Section XI.D.4.c. above). Moreover, a finding that Unitil is a riskier investment because of the regulatory framework we established in D.P.U. 20-80-B is inconsistent with Unitil's own statement to its investors that it is "well positioned" regarding the clean energy transition in Massachusetts because of the high overlap between its electric and gas customers (RR-DPU-49, Att. 1, at 6). Therefore, we find that adjustments to Unitil's ROE based on the approved PBR plans or the Massachusetts operating environment are not appropriate based on our precedent and the record evidence.

g. Qualitative Factors

The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase One) at 224-225; see also Boston Edison, 375 Mass. 1, 11 ("The rate of return is not an immutable number, but rather one chosen from a range of reasonable rates and determined by the Department to appropriate under the circumstances"); Boston Gas, 359 Mass. 292, 305 (holding that the Department was not required to rely on any particular group of comparative figures to estimate ROE, as "[s]uch comparisons usually can be no more than general guides to be appraised by the [Department] in considering the fairness of rates. . . ."). It is both the Department's long-standing precedent and accepted regulatory practice[213] to consider qualitative factors such as management performance and customer service in setting a fair and reasonable ROE. See, e.g., D.P.U. 09-39, at 399-400 (considered company's assistance to municipal and public safety officials to restore power to the customers of another company following a severe ice storm in setting allowed ROE); D.P.U. 12-86, at 257-258 (deficiencies regarding affiliate

[213] See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Pub. Serv. Corp. v. Citizens' Util. Bd., Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE); US West Commc'ns, Inc. v. Washington Utils. and Transp. Comm'n, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utils. Comm'n v. Gen. Tel. Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefore).

transactions and selection of rate case consultants warranted ROE at lower end of reasonable range). Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on above-average or subpar management performance and customer service.

The Attorney General has not presented any specific evidence of subpar management performance or customer service (see generally Attorney General Brief; Attorney General Reply Brief). Instead, the Attorney General asserts, without citing precedent, that Unitil's authorized ROE should be set at the low end of the reasonable range based solely on a comparison of the Company's delivery rates to the delivery rates of other Massachusetts EDCs and LDCs (Attorney General Brief at 59-62; Attorney General Reply Brief at 1-3). We find that the Attorney General's position is inconsistent with the principles of cost-of-service ratemaking and an insufficient basis upon which to allow an ROE at the lower end of the reasonable range.

In addition, we have considered Unitil's arguments that a recent decline in the Company's non-fixed operating expenses despite inflation and customer satisfaction support an authorized ROE in the higher end of the reasonable range (Company Brief at 334 (electric); Company Brief at 267-268 (gas)). Even assuming Unitil's facts to be true, the Department does not find that the Company has produced evidence of exemplary performance that would justify authorizing Unitil's ROE at the upper end of the reasonable range.

5. Conclusion

Based on a review of the evidence presented in this case, the arguments of the parties, and the considerations set forth above, the Department finds that an authorized ROE of 9.40 percent is within a reasonable range of cost of equity rates that will preserve the Company's financial integrity, allow it to attract capital on reasonable terms and, for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case.[214] In making this finding, the Department has exercised its expertise and informed judgment and has considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

XII. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. G.L. c. 25, § 1A; D.P.U. 22-22, at 404; D.P.U. 20-120, at 412; D.P.U. 19-120, at 409.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest cost means for society as a whole. Thus, efficiency in rate structure means that it is

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214 In setting this ROE, the Department has taken into consideration the amount of the storm fund assessment paid by the Company pursuant to G.L. c. 25, § 18. See, e.g., Fitchburg Gas and Electric Light Company et al. v. Department of Public Utilities, 467 Mass. 768 (2014); Storm Trust Fund Assessment, D.P.U. 24-ASMT-03 (March 14, 2024).

cost-based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 22-22, at 405; D.P.U. 20-120, at 412; D.P.U. 19-120, at 409.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. In setting rates, the Department balances fairness and equity. Fairness means that no class of consumers should pay more than the costs of serving that class. Equity, in rate structure, means that the Department considers affordability among customers in establishing rate classes and when establishing discount rates for low-income customers.[215] Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. G.L. c. 25, § 1A; D.P.U. 22-22, at 405; D.P.U. 20-120, at 413; D.P.U. 19-120, at 409-410.

There are two parts to determine rate structure: cost allocation and rate design. Cost allocation assigns a portion of a company's total costs to rate classes through an embedded ACOSS. The ACOSS represents the cost of serving each rate class at equalized rates of return given the company's level of total costs. D.P.U. 22-22, at 405-406; D.P.U. 20-120, at 413; D.P.U. 19-120, at 410.

There are four steps to develop an ACOSS. The first step is to functionalize costs. In this step, costs are categorized with the production, transmission, or distribution function of providing service or other categories associated with the various functions of providing

215 The Department addresses the low-income discount rate and compliance with G.L. c. 164, § 141 in Section XII.D. below.

distribution service. The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as demand, energy, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen and then to sum for each rate class the costs allocated to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 22-22, at 406; D.P.U. 20-120, at 413; D.P.U. 19-120, at 410.

The results of the ACOSS are compared to normalized revenues billed to each rate class in the test-year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes so as to set rates at equalized rates of return to ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 22-22, at 406; D.P.U. 20-120, at 414; D.P.U. 19-120, at 411.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an ACOSS, but also explicitly considers the effect of its rate structure decisions on the amount that customers are billed. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. In addition, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low-income customers and considers the effect of such rates and rate changes on low-income customers. G.L. c. 25, § 1A; D.P.U. 22-22, at 407;

D.P.U. 20-120, at 414; D.P.U. 19-120, at 411. To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies - or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i).[216] In addition, G.L. c. 164, § 94*I* ("Section 94*I*") requires the Department, in each base distribution rate proceeding, to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent.[217] The Department reaffirms its rate structure goals are designed to result in rates that are fair and cost-based and that enable customers to adjust to changes. D.P.U. 22-22, at 408; D.P.U. 20-120, at 415; D.P.U. 19-120, at 412.

The second part of determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is

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216 By enacting G.L. c. 164, § 1F(4)(i) the Legislature substantially adopted the Department's structure, eligibility requirements, and rules governing discounted rates for low-income customers of electric and gas companies.

217 Section 94*I* provides:

> In each base distribution rate proceeding conducted by the Department under Section 94, the Department shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any one customer class would be more than ten percent, the Department shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the Department.

that a given rate class should produce sufficient revenues to cover the cost of serving the given rate class and, to the extent possible, meet the Department's rate structure goals discussed above. D.P.U. 22-22, at 408; D.P.U. 20-120, at 415; D.P.U. 19-120, at 412.

B. Electric Cost Allocation

1. Company Proposal

Unitil performed an ACOSS for its electric division to determine the embedded costs of serving its various electric retail customers and support its rate design efforts (Exhs. Unitil-JDT-1, at 1 (electric); Unitil-JDT-3 & Revs. 2, 4 (electric)). Unitil's ACOSS allocated its electric distribution costs to its rate classes (Exh. Unitil-JDT-1, at 1 (electric)). Unitil developed its ACOSS using three primary steps. The first step is cost functionalization, in which the Company identified and separated plant and expenses, using FERC plant accounts and associated investment balances, into specific categories based on the characteristics of the utility's operation (Exhs. Unitil-JDT-1, at 4 (electric); Unitil-JDT-3, at 3 (Rev. 4) (electric)). Costs were grouped, or functionalized, as power supply, substation, distribution primary, distribution secondary, transformation, onsite & metering, customer accounts & service, and lighting plant (Exh. Unitil-JDT-1, at 4-5 (electric)). Whenever possible, costs were directly assigned to a functional category, and indirect supporting costs were allocated to functions using allocation factors related to plant or labor ratios (Exh. Unitil-JDT-1, at 5 (electric)).

In the second step, the Company classified costs, which further separated the functionalized costs according to the primary factors determining the level of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the system; and (3) the amount of electricity consumed by customers (Exh. Unitil-JDT-1, at 5 (electric)). The classification categories in the Company's ACOSS are: (1) customer costs; (2) demand costs; and (3) energy costs (Exhs. Unitil-JDT-1, at 5 (electric); Unitil-JDT-3, at 3-4 (Rev. 4) (electric)).[218]

Cost classification was largely done by knowing the type of activities or assets that reside in a particular FERC account, and in such instances, the account as a whole was classified (Exh. Unitil-JDT-1, at 6 (electric)). For others, however, classification studies were performed to determine the portion of an account associated with each classification (Exh. Unitil-JDT-1, at 6 (electric)). The Company utilized the National Association of Public Utility Commissioners ("NARUC") Cost Allocation Manual ("NARUC Manual") to guide its classification activities (Exh. Unitil-JDT-1, at 6 (electric)).

The Company stated that for certain facilities, specifically distribution plant reflected in FERC accounts 364 (Poles, Towers, and Fixtures), 365 (Overhead Conductors), 367 (Underground Conductors), and 368 (Line Transformers), it was appropriate to classify costs as customer- or demand-related costs using a minimum system study ("MSS"), which recognizes that such assets have a dual purpose: (1) to meet peak demands; and (2) to connect customers to

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218 Demand cost allocators are largely a function of coincident and non-coincident peaks, which are in turn a function of line losses (Exhs. Unitil-JDT-3, at 26 (Rev. 4) (electric); Unitil-JDT-External Allocators Electric (Rev. 4) (Excel, tab Loss Factors) (electric)). The Company's most recent line loss study was performed in 2009 (Exh. DPU 35-11 (electric)). The Company included a line loss study in an RFP issued in connection with the retention of consultants in this rate proceeding but did not receive any responses (Exh. DPU 35-11 (electric)). Given the recent and expected investments in the distribution system in preparation for increased electrification, the Department directs the Company to solicit an updated line loss study in advance of its next distribution base rate case proceeding.

the distribution system (Exhs. Unitil-JDT-1, at 6-7 (electric); Unitil-JDT-3, Sch. 5 (Rev. 4) (electric)).

The third step was cost allocation, in which the functionalized and classified costs were allocated to customer rate classes that benefit from the cost (Exh. Unitil-JDT-1, at 7 (electric); Unitil-JDT-3, at 4 (Rev. 4) (electric)). Customers were divided into classes based on the type and character of services they require, and costs were typically allocated to these classes based on the number of customers as well as the capacity required to serve those customers (Exh. Unitil-JDT-1, at 7 (electric)). Similar to prior steps, Unitil directly assigned certain costs to certain customer groups and developed allocation factors for common costs (Exh. Unitil-JDT-1, at 11-14 (electric)).

After completing the ACOSS steps, the Company calculated the revenue deficiency (Exh. Unitil-JDT-1, at 11-15 (electric)). Since costs associated with special contracts were not specifically identified and therefore assigned to all classes, special contract revenues were credited to all customer groups, resulting in a total revenue deficiency of approximately $6.776 million[219] (Exh. Unitil-JDT-1, at 11-15 (electric)). This value was offset by approximately $2.674 million in revenue transfers associated with the revenue requirement from reconciling mechanisms proposed to be moved into base distribution rates (Exh. Unitil-JDT-1, at 11-15 (electric)). This deficiency was calculated for each of the six broad groups of customer classes used in the Company's ACOSS, consisting of residential customers, small general service

219 Based on changes made during the proceeding, the Company's total revenue deficiency was revised and decreased to $5,142,340 (Exh. Unitil-CGDN-10, at 1 (Rev. 4) (electric)); see also Schedule 1 (electric) below).

customers, regular general service customers, large general service customers, company-owned outdoor lighting customers, and customer-owned outdoor lighting customers (Exh. Unitil-JDT-1, at 10 (electric)).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company's ACOSS is flawed because it uses an MSS to allocate costs in Account 364 (Poles, Towers, and Fixtures), Account 365 (Overhead Conductors), Account 367 (Underground Conductors), and Account 368 (Line Transformers) (Attorney General Brief at 78, 82). The Attorney General argues that MSS and related studies are "fundamentally flawed and provided little to no value for setting just and reasonable rates," and therefore the Company's ACOSS should be rejected (Attorney General Brief at 78, citing Exh. AG-DED-1, at 74). The Attorney General contends that the MSS is based on an unreasonable hypothetical setting in which a distribution system is built to serve customers but not to serve load (Attorney General Brief at 78). According to the Attorney General, any minimum electric distribution system actually constructed would service at least a portion of customers' loads (Attorney General Brief at 78, citing Exh. AG-DED-1, at 77).

Further, the Attorney General argues that another flaw of the MSS-based approach is the lack of an observable empirical relationship between distribution system costs and the number of utility customers (Attorney General Brief at 79; Attorney General Reply Brief at 20). In this regard, the Attorney General asserts that the Company's growth in relevant distribution plant investments was correlated with, if anything, reduced growth in customer count (Attorney General Brief at 79, citing Exhs. Unitil-JDT-Rebuttal at 10 (electric); AG-DED-Surrebuttal-1, at 12-13; RR-AG-4; Attorney General Reply Brief at 20). The Attorney General contends that the lack of an observable relationship between distribution system costs and changes in customer counts is consistent with decades of academic literature and that ultimately treating distribution system costs as customer-related is fundamentally indefensible (Attorney General Brief at 79-80, citing Exh. AG-DED-1, at 79-80; Attorney General Reply Brief at 20).

The Attorney General also rejects the notion that dismissing an MSS ignores economies of scale in equipment to serve large customers (Attorney General Brief at 80, citing Exh. Unitil-JDT-Rebuttal at 11 (electric)). According to the Attorney General, the presence of economies of scale does not support the arbitrary classification of a customer component, but instead would imply that the Company should have conducted a special cost study examining the relative installation costs of different transformer assets used to serve different customer classes (Attorney General Brief at 80, citing Exh. AG-DED-Surrebuttal-1, at 13-14).

The Attorney General also asserts that several other jurisdictions have rejected the use of an MSS (Attorney General Brief at 80, citing Exh. AG-DED-1, at 80). In this regard, the Attorney General contends that the Company's own survey of MSS use throughout the United States shows only 23 examples of individual utilities using the approach (Attorney General Brief at 81, citing Exh. Unitil-JDT-Rebuttal at 9-10 (electric)). In conclusion, the Attorney General recommends that the Department accept the results of her alternative ACOSS, which classifies distribution plant accounts 364-368 as 100 percent demand related (Attorney General Brief at 82, citing Exh. AG-DED-1, at 80).

b. Company

The Company argues that the cost allocation method used in the MSS approach is based on the specific design and operating characteristics of the Company's distribution system, and, therefore, provides a more accurate and consistent measure of class cost responsibility than other approaches for providing distribution service to customers (Company Brief at 353 (electric); Company Reply Brief at 62). Unitil contends that it provided evidence that its use of an MSS for classifying distribution plant assets is entirely appropriate (Company Brief at 369 (electric)). In support of its position, the Company asserts that the NARUC Manual specifically notes that distribution-related facilities should be classified as either customer- or demand-related, or a combination of both (Company Brief at 369 (electric), citing NARUC Manual at 89, 96-98). Further, the Company argues that an MSS appropriately recognizes that these assets have a dual purpose to meet peak demands and to connect customers to the system and estimates the portion of the utility's investment affected by both purposes (Company Brief at 369 (electric), citing Exh. Unitil-JDT-Rebuttal at 7-8 (electric)). Thus, the Company contends that regardless of how a correlation occurs, a utility must connect customers (Company Brief at 369 (electric)).

Further, Unitil dismisses the Attorney General's attempt to correlate the change in customer count and the change in plant investment, as the Company contends that investments are often planned years in advance and may not align with an annual change in customer counts (Company Brief at 369-370 (electric)). Thus, the Company asserts that it would be inefficient and not cost-effective to attempt to make only investments that can be tied to the specific immediate incremental demand associated with an added customer or customers (Company Brief at 370 (electric)). According to the Company, the appropriate manner to assess the relationship between total costs and customer count is to use total costs in the analysis, and not to review only the change in costs (Company Brief at 370 (electric)). In this regard, the Company maintains that its analysis appropriately reviews the correlation between total costs rather than a change in costs (Company Brief at 370 (electric)).

The Company claims that a separate cost study was unnecessary to examine economies of scale, as the MSS allocates the minimum size based on customer count and the additional capacity requirements on non-coincident demand, resulting in a fair and equitable allocation to the classes that reflects economies of scale (Company Brief at 371 (electric)). Moreover, the Company asserts that its survey of other jurisdictions provides an illustration that 23 utilities rely on the MSS method, rather than a comprehensive study of methods employed by all the electric investor-owned utilities (Company Brief at 372 (electric)). The Company notes that the Attorney General has also not conducted a comprehensive survey of utilities (Company Brief at 372 (electric); Company Reply Brief at 62).

3. Analysis and Findings

The Department requires that cost allocation methods be driven by cost-causation principles. See D.P.U. 17-170, at 318; D.P.U. 11-01/D.P.U. 11-02, at 320; D.P.U. 10-114, at 187; D.P.U. 10-55, at 534. In the instant case, the Department has weighed the competing cost allocation methods proposed by the Company and the Attorney General (Exhs. Unitil-JDT-1, at 6-7, 11 (electric); Unitil-JDT-Rebuttal at 6-12 (electric); AG-DED-1, at 5-6, 75-80; AG-DED-3, Schs. 9-13; AG-DED-Surrebuttal-1, at 12-14).

The Company used a traditional three-step approach to its electric division ACOSS (Exhs. Unitil-JDT-1, at 4 (electric); Unitil-JDT-3, at 3-4 (Rev. 4) (electric)). We find this approach to be acceptable, with the exception of using the MSS to classify costs in accounts 364 (Poles, Towers, and Fixtures), 365 (Overhead Conductors), 367 (Underground Conductors), and 368 (Line Transformers) (Exhs. Unitil-JDT-1, at 6-7 (electric); Unitil-JDT-3, Sch. 5 (Rev. 4) (electric)).

In the instant case, the Department is persuaded that the Company should classify the costs in FERC accounts 364, 365, 367, and 368 as demand-related costs. As an initial matter, we note that an MSS has not been used in recent electric base distribution rate cases. See, e.g., D.P.U. 22-22, at 418-420; D.P.U. 18-150, at 511. Further, a distribution system would not be designed and built such that customers would be connected but not receive service. In addition, given the types of costs in question, related assets must be sized to serve the maximum load placed on the distribution system. The number of customers, for this purpose, does not drive the need for and size of these assets; the load placed on the system is the determinant of what is appropriately placed in service.

The Department also finds that for the allocation of the relevant costs related to FERC accounts 364, 365, 367, and 368, the use of a cost allocator associated with demand instead of an allocator derived from the number of customers in a rate class is more aligned with the principle of cost causation. D.P.U. 17-05-B at 25, 27, citing D.P.U. 15-155, Exh. NG-PP-2(c) at 1; D.P.U. 10-70, Exh. WM-EAD at 7-8; see also D.P.U. 09-39, at 413. Further, as discussed in Section XII.C.3. below, the proposed customer charges are insufficient to collect the entire customer portion of customer-related costs as determined by the ACOSS. We find that allocating the relevant costs using a demand allocator instead of a customer allocator would likely have no impact on the customer charges proposed by the Company. Therefore, the

Department directs the Company to use the appropriate demand allocator for costs related to FERC accounts 364, 365, 367, and 368.

With respect to the relationship between distribution costs and customer counts, the Department is not persuaded that a similar increase in both categories is indicative of a causal relationship between the two. Rather, the distribution system is primarily a function of the demand placed on the system and, to a lesser degree, the number of customers. It is possible for there to be changes in system demand requiring increased investment with zero change in customer counts. While the Company demonstrated a high degree of correlation between total customer counts and total distribution plant investment balances (Exh. Unitil-JDT-Rebuttal at 10-11), this does not indicate a causal relationship.

Finally, we are not persuaded by the Company's suggestion that the MSS is necessary to capture economies of scale (Company Brief at 371 (electric)). Rather, we are satisfied in this instance that economies of scale are captured by classifying all costs as demand-related, as the relevant costs are also functionalized into primary and secondary distribution categories. Primary distribution assets serve larger customers and, therefore, these customers bear a higher proportion of primary distribution costs than smaller customers (Exh. Unitil-JDT-3, at 26 (Rev. 4) (electric)). Secondary distribution assets serve smaller customers and, therefore, residential and small C&I customers are allocated a significantly higher proportion of costs using a non-coincident peak allocator for secondary distribution than for primary distribution.[220]

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220 The non-coincident peak demand allocator for residential customers for primary distribution assets is approximately 54 percent, and approximately 97 percent for secondary distribution assets (Exh. Unitil-JDT-3, at 26 (Rev. 4) (electric)).

C. Electric Rate Design

1. Introduction

Unitil's proposed rate structure includes two residential customer classes, Rate RD-1 and Rate RD-2, which are differentiated based on whether the customer receives a discounted rate based on low-income eligibility (Exh. Unitil-JDT-1, at 10 (electric); proposed M.D.P.U. Nos. 398, 399 (electric)). The Company also offers an optional residential time-of-use ("TOU") rate for EV charging only (proposed M.D.P.U. No. 403 (electric)). The Company has five C&I rate classes, GD-1, GD-2, GD-3, GD-4, GD-5, which are differentiated based on the size of customers' loads (Exh. Unitil-JDT-1, at 10 (electric); proposed M.D.P.U. No. 400 (electric)). Of the five C&I classes, two are closed rates, Rate GD-4 is for optional TOU customers, and Rate GD-5 is for water and space heating load (proposed M.D.P.U. No. 400, Sheet 4 (electric)). Unitil also offers EV demand charge alternatives within its Rates GD-2 and GD-3 (proposed M.D.P.U. No. 400, Sheets 3, 7 (electric)). Finally, the Company offers two outdoor lighting options, Rate SD and Rate SDC differentiated between Company-owned and customer-owned equipment (Exh. Unitil-JDT-1, at 10 (electric); proposed M.D.P.U. Nos. 401, 402 (electric)).

2. Distribution Revenue Increase and Cap

a. Company Proposal

The Company's ACOSS produced a revenue requirement at equalized rates of return for each customer group. The Company grouped rate classes as follows: (1) residential customers (RD-1, RD-2); (2) small C&I customers (GD-1); (3) regular C&I customers (GD-2, GD-4, GD-5); (4) large C&I customers (GD-3); (5) company-owned outdoor lighting customers (SD);

and (6) customer-owned outdoor lighting customers (SDC) (Exhs. Unitil-JDT-1, at 10; Unitil-JDT-3, at 6 (Rev. 4) (electric)). To allocate the revenue requirement from the group level to the rate class level, the Company allocated the revenue requirement for each group in the ACOSS to rate classes based on each class's share of test year billed revenue for each group (Exh. Unitil-JDT-4, Sch. 1 (Rev. 4) (electric)).

Consistent with Department precedent, the Company then executed a revenue apportionment process that consisted of deriving a reasonable balance among various criteria, including the ACOSS results, each class's contribution to test-year revenue levels, and customer impact considerations (Exh. Unitil-JDT-1, at 18 (electric)). The Company's revenue apportionment process has three limits. First, the Company shifted the excess base distribution revenue requirement from classes in which the ACOSS assigned an increase above 150 percent of the overall system average base distribution increase to classes with such increases that were less than 150 percent above the overall system average base distribution increase (Exhs. Unitil-JDT-1, at 18-20 (electric); Unitil-JDT-4, Sch. 1, at 2 (Rev. 4) (electric)). Next, the Company implemented a zero percent increase revenue floor, by proposing that no rate class would receive a decrease from test year normalized revenues (Exhs. Unitil-JDT-1, at 18-19 (electric); Unitil-JDT-4, Sch. 1, at 3 (Rev. 4) (electric)). As such, the Company allocated all revenue requirement decreases to classes receiving revenue requirement increases (Exhs. Unitil-JDT-1, at 18-19 (electric); Unitil-JDT-4, Sch. 1, at 3 (Rev. 4) (electric)). Finally, the Company shifted the total distribution revenue requirement from classes receiving an increase in excess of ten percent above total test year normalized revenues to those classes receiving an increase less than ten percent above total test year revenues (Exhs. Unitil-JDT-1, at 19 (electric); Unitil-JDT-4, Sch. 1, at 1 (Rev. 4) (electric)). Once the total revenue requirement was allocated to each rate class, the Company determined its proposed customer, energy, and demand charges on a rate-by-rate basis, as discussed below (Exh. Unitil-JDT-1, at 20 (electric)).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Company's proposed electric revenue distribution is fundamentally flawed because it is inconsistent with the concept of rate gradualism (Attorney General Brief at 82, citing Exh. AG-DED-1, at 84). In particular, the Attorney General takes issue with the Company's proposal to limit increases to each electric class to no more than 150 percent (or 1.5 times) of the overall proposed system average electric system increase (Attorney General Brief at 82). Instead, the Attorney General recommends that the Department use a revenue allocation based on the Attorney General's alternative ACOSS results, with rate increases to each electric class limited to no more than 125 percent (or 1.25 times) of the overall electric system increase (Attorney General Brief at 82, citing Exh. AG-DED-1, at 85).

ii. Company

The Company argues that its proposed revenue distribution is fair and equitable and in alignment with past Department findings (Company Brief at 373 (electric)). Unitil rejects the contention that its proposal to limit the rate increase to 150 percent of the overall electric system average violates principles of gradualism (Company Brief at 373 (electric)). The Company asserts the Attorney General provides no justification for her recommendation to limit the increase to 125 percent of the overall electric system average (Company Brief at 373 (electric)).

c. Analysis and Findings

As noted in Section XII.A. above, the Department considers multiple goals in designing utility rate structures. In the development of the ACOSS and throughout the rate design process, the Department notes that the concepts of cost causation and gradualism can often support differing policy goals. In the instant case, the Attorney General asserts that the Company's rate increase proposal is inconsistent with the principle of rate gradualism (Attorney General Brief at 82). The Attorney General's recommendations therefore place greater weight on the concept of gradualism.

The Department notes, however, that the resulting reallocation of revenue requirement from certain rate classes onto others increases cross-subsidization, which is inconsistent with the principle of cost causation. D.P.U. 22-22, at 449-450. In addition to considering the principles of rate design, the Department must also weigh the other parameters used in final cost allocation to rate classes when determining a suitable base distribution revenue cap. D.P.U. 22-22, at 452. Specifically, in the instant case, the presence of a revenue floor reduces the increases to other rate classes and allows a proper balancing of the Department's goals of fairness and continuity at a higher base distribution revenue cap, and thus moves rate classes closer to equalized rates of return overall (Exhs. Unitil-JDT-1, at 18-19 (electric); Unitil-JDT-4, Sch. 1, at 3 (Rev. 4) (electric)). See D.P.U. 22-22, at 452.

The Company proposes limiting the maximum increase in base distribution rates to any rate class to 150 percent of the overall base distribution rate increase (Exhs. Unitil-JDT-1, at 18-20 (electric); Unitil-JDT-4, Sch. 1, at 2 (Rev. 4) (electric)). We find that this approach is a reasonable step in mitigating cross-subsidies, and it can prevent the disproportionate burdening of certain customer classes with excessive rate escalations. This approach aligns with the Department's principles of rate continuity and fairness in the rate-setting process. The reallocation of revenue requirement among rate classes using a base distribution cap of 125 percent, as recommended by the Attorney General, would increase cross-subsidization relative to the Company's proposed 150-percent cap, resulting in certain customer classes bearing a higher share of costs over their cost of service than other rate classes. We conclude that limiting the maximum increase in base distribution rates to any rate class to 150 percent of the system average is reasonable, supports a more balanced distribution of cost responsibilities among rate classes (thereby mitigating the risk of cross-subsidization) promotes rate stability, and ensures compliance with regulatory requirements. As previously noted, the Department's goals of fairness and equity include ensuring that the final rates to each rate class represent or approach the cost to serve that class.

In response to Section 94*I*, the Department has evaluated the impacts of the rate class distribution revenue increases based on equalized rates of return, and the revenue adjustments for costs recovered through reconciling mechanisms approved in the instant case to determine whether the impact to any rate classes exceeded ten-percent of total revenues. See, e.g., D.P.U. 22-22, at 450-451; D.P.U. 20-120, at 483-484; D.P.U. 19-120, at 432; D.P.U. 15-80/D.P.U. 15-81, at 303. The total approved revenue increase for Unitil's electric division is below ten percent, but certain rate classes had increases exceeding ten percent (see Schedule 10 below). Accordingly, the Department directs Unitil in its compliance filing to apply for the electric division a ten-percent cap on the total distribution revenue increase for each rate class (inclusive of the costs recovered through reconciling mechanisms as adjusted in this Order), and then to reallocate the base distribution revenues in excess of the ten-percent cap to the other rate classes to the extent they have room under the cap, as demonstrated on illustrative Schedule 10 for the electric division below.[221]

Finally, we find the use of a zero percent increase revenue floor appropriate. The Company, however, erred in applying the floor to total revenues (Exhs. Unitil-JDT-1, at 18-19 (electric); Unitil-JDT-4, Sch. 1, at 3 (Rev. 4) (electric)). Costs and revenues associated with reconciling mechanisms are not a direct function of the ACOSS and can change annually from collecting under-recoveries to crediting over-recoveries. Therefore, we find that implementing a zero percent revenue floor on base distribution revenues provides a more equitable result, through exclusion of reconciling revenues that vary from year to year. D.P.U. 22-22, at 452. Further, using base distribution revenues avoids further reallocation of distribution revenue targets and ensures that the revenue floor more accurately reflects the cost of service. D.P.U. 22-22, at 452. Therefore, in its final revenue apportionment the Department requires the Company to implement its revenue floor on the base distribution revenue requirement only, as shown in the Department's illustrative Schedule 10 for the electric division below.

3. <u>Customer Charges</u>

a. <u>Company Proposal</u>

Unitil proposes to increase the customer charge for all rate classes as part of its efforts to incrementally move customer charges closer to the customer unit costs as presented in its

[221] Consistent with Department precedent, Section 94*I* applies to the revenue adjustments for costs recovered through reconciling mechanisms that are approved in a base distribution rate case as well as the approved increase to base distribution rates. D.P.U. 20-120, at 484-485 n.234; D.P.U. 14-150, at 397-398.

ACOSS (Exh. Unitil-JDT-1, at 20 (electric)). At present, each customer class's customer charge is below the unit cost per the ACOSS, as each customer charge collects between 20 percent and 64 percent of its associated unit costs (see Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rates) (electric)). As discussed in Section XII.C.2. above, the Company proposed to increase fixed customer charges by 150 percent of the overall electric system average increase (Exhs. Unitil-JDT-1, at 18-20 (electric); Unitil-JDT-4, Sch. 1, at 2 (Rev. 4) (electric)). In the initial filing, the proposed overall electric system average increase was approximately 13.56 percent, thus making the increase in fixed customer charges equal to 20.34 percent (Exh. Unitil-JDT-1, at 18-20 (electric)). The Company proposed that if the 20.34 percent increase did not result in a customer charge that recovered at least 25 percent of the unit cost per the ACOSS, then the customer charge would be set at 25 percent of the ACOSS unit cost (Exh. Unitil-JDT-1, at 20 (electric)).[222]

During the proceeding, the Company revised its proposed Rate GD-4 monthly customer charge of $12.00 to maintain it at the current amount of $10.00 (Exh. Unitil-JDT-5, at 6 (Rev. 2) (electric)). In conjunction with this proposed revision, other proposed adjustments to the cost of service increased the Company's proposed overall system average increase to 19.6 percent, which in turn adjusted the proposed customer charge increases to 29.4 percent (Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rates) (electric)).

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[222] Although the Company initially proposed an exception to this approach for Rates GD-2, GD-4, and GD-3, which it stated would have customer charges set close to the unit costs per the ACOSS, the Company subsequently updated its proposal for Rate GD-4 (see above), and noted that the unit cost for the G-3 rate was $1,385.35 compared to the proposed customer charge of $338.75, which is not close to the unit cost as stated in Exh. Unitil-JDT-1, at 20 (Exh. Unitil-JDT-1, at 20 (electric); Tr. 9, at 853-855).

The Company states that its proposed customer charges are appropriate because they are based on distribution costs that do not vary based on the amount of energy consumed, but rather vary based on the demand placed on the system and the number of customers served (Exh. Unitil-JDT-1, at 20 (electric)). The Company also notes that the ACOSS provides a conservative estimate of fixed costs because the ACOSS classified only direct customer costs that vary with the number of customers in its customer unit cost (Exh. Unitil-JDT-1, at 20-21 (electric)).

b. Positions of the Parties

i. Attorney General

The Attorney General urges the Department to reject the Company's proposal to increase the electric division's customer charges for residential and small C&I customers (Attorney General Brief at 83). The Attorney General contends that the Company's proposal contradicts the Department's policy goals of promoting energy efficiency, affordability, and equity objectives (Attorney General Brief at 83; Attorney General Reply Brief at 20-21). In particular, she argues that these increases would discourage energy efficiency efforts and disproportionately burden lower-income customers (Attorney General Brief at 83).

The Attorney General recommends that the Department restrict such increases to no more than the Company's initially proposed system average increase of 13.56 percent (Attorney General Brief at 83-84). Specifically, the Attorney General states the Department should cap the monthly customer charge for residential customers at $8.50 and cap the monthly customer charges for small C&I customers at $11.50 (Attorney General Brief at 84).

ii. DOER

DOER recommends approval of the customer charges proposed by the Company to support a just, reasonable, and more cost-reflective electric rate design, while balancing the incentives for electrification and energy efficiency (DOER Brief at 18; DOER Reply Brief at 11). DOER submits that by keeping the customer charges fixed for the past ten years and not subject to inflationary pressures, the incentive to deploy energy efficiency solutions increased during this period since a smaller proportion of a customer's income was allocated to a fixed, unavoidable charge (DOER Brief at 19). Further, DOER argues that, on balance, the relatively modest proposed increases are not a disincentive for energy efficiency and suppress volumetric energy rates that otherwise may disincentivize electrification (DOER Brief at 19-20). In this regard, DOER asserts that higher volumetric rates will disincentivize strategic electrification and jeopardize the Commonwealth's central decarbonization strategy to electrify the heating and transportation sectors (DOER Reply Brief at 10). Finally, DOER contends that as the Commonwealth moves toward electrification, all customers will increase their electricity usage but, with added incentives for low-income customers, the correlation between household income and electric usage is likely to lessen and reduce concerns about the disproportionate impact of higher customer charges on low-income customers (DOER Reply Brief at 11).

iii. Company

The Company asserts that its proposed changes to the customer charges are intended to incrementally move the customer charges closer to the related costs for each rate class and support the Commonwealth's electrification policies (Company Brief at 374 (electric)). The Company argues that the Attorney General provides no basis or support for the conclusion that a lower customer charge is more consistent with, or results in achieving, energy conservation and efficiency goals (Company Brief at 375 (electric)). According to the Company, customers respond to price signals and rate changes in complicated and inconsistent ways, and the Attorney General offers an unreasonably narrow definition of conservation in her assessment of the customer charges (Company Brief at 375 (electric)).

c. Analysis and Findings

In setting customer charges, the Department must balance the competing rate structure goals of efficiency (i.e., setting the customer charge to recover its cost to serve) and rate continuity. D.P.U. 15-80/D.P.U. 15-81, at 328; D.P.U. 14-150, at 400; D.P.U. 10-55, at 561. The Department considers multiple factors in making its decisions regarding allowable costs, the resulting change in rates, and the resulting customer bills. D.P.U. 22-22, at 480. There is no single optimal method of setting rates that will impact all customers equally. D.P.U. 22-22, at 480. The Department recognizes that some changes can have disproportionate impacts on different customers. For a product that is priced using both a fixed charge and a variable charge, all else equal, a customer with low usage will experience a greater impact related to an increase in the fixed charge than a customer with high usage. D.P.U. 22-22, at 480. Similarly, all else equal, a customer with high usage will experience a greater impact related to an increase in the volumetric charge than a lower usage customer. D.P.U. 22-22, at 480. This is not the case in the instant proceeding; rather the Company is proposing to increase the customer charge by a larger percentage than the proposed increase in the variable rate.

The record shows that each of the Company's rate classes' customer charge is below the unit customer cost per its ACOSS (Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rates) (electric)). The Company endeavored to design its proposed customer charges to approach the embedded unit cost as calculated in its ACOSS while being sensitive to the principle of gradualism (Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rates) (electric)). As noted above, the Company proposed to accomplish this by first increasing the fixed customer charges by 150 percent of the overall system average increase and, if that did not result in a customer charge that recovered at least 25 percent of the unit cost per the ACOSS, then the customer charge was set at 25 percent of the ACOSS unit cost (Exhs. Unitil-JDT-1, at 18-20 (electric); Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rates) (electric)). The Company has demonstrated that, with the exception of Rate GD-3 as discussed below, the proposed customer charges will assist in providing the appropriate price signals to customers to encourage efficient use of the distribution system (Exh. Unitil-JDT-5 (Rev. 4) (electric)).

Further, as noted in Section XII.D.4. below, the Department approved the increase in the low-income discount rate for electric customers from 34.5 percent to 40 percent. We find that the increase in the low-income discount rate will assist in mitigating the customer charge-related bill impacts to low-income customers (Exh. Unitil-JDT-5, at 2 (Rev. 4) (electric)). While the Company proposes to maintain or increase customer charges, it is not proposing decreases in the volumetric energy rates for classes other than GD-1; rather it is proposing to allocate its increased revenue requirement through increases in both charges (Exh. Unitil-JDT-4, Sch. 2 (Rev. 4) (electric)). Based on these considerations, we are persuaded that the initially proposed customer charges, and the Department-approved customer charge for Rate GD-3, are reasonable. Individual rate class customer charges will be addressed in Section XII.G. below.

With respect to the Attorney General's position that the proposed increase in customer charges conflicts with Department's energy efficiency objectives (Attorney General Brief at 83; Attorney General Reply Brief at 20-21), the Department does not agree in this instance. While the proposed customer charge increase represents a larger percentage increase relative to the volumetric energy rate increase, both charges are increasing for most rate classes (Exh. Unitil-JDT-4, Sch. 2 (Rev. 4) (electric)). Further, the Commonwealth's transition to clean energy will require increased electrification. Increasing the customer charge by a greater percentage relative to volumetric energy rates recognizes the role of rate signals in progressing toward decarbonization.

Further, while the Attorney General provided an alternative ACOSS removing the customer component of assets in FERC accounts 364, 365, 367, and 368 as discussed in Section XII.B. above the Department notes that assuming the same revenue requirement, the embedded customer unit costs stemming from the ACOSS are the same for both the Company's and the Attorney General's analyses (Exhs. Unitil-JDT-3, at 15 (Rev. 4) (electric); AG-DED-3, Sch. 11, at Unit Cost tab (Excel)). This result is due to the embedded customer unit costs including only direct facilities related to meters, services, and the FERC 900 account series related to billing (Tr. 9, at 850-851). The assets that the Attorney General proposes to functionalize as demand-related rather than customer-related are distribution plant assets, which the Company proposes to collect in the variable charge component of bills (Tr. 9, at 850-851).

D. Low-Income Discount – Electric Division

1. Introduction

Pursuant to G.L. c. 164, § 1F, the Department requires distribution companies to provide discounted rates for low-income customers comparable to the low-income discount rate received off the total bill for rates in effect prior to March 1, 1998. See also Expanding Low Income Customer Protections and Assistance, D.P.U. 08-4, at 36 (2008). In D.P.U. 15-155, the Department determined that a compensating adjustment to the low-income discount rate to comply with G.L. c. 164, § 141[223] would include costs associated with the Renewable Portfolio Standard solar carve out and the Net Metering Recovery Surcharge ("NMRS"). D.P.U. 15-155, at 470-471. Further, in D.P.U. 22-22, the Department directed the EDCs to "explore stratifying low-income discount rates in a manner that provides an equitable discount for customers, provides assistance for the most vulnerable customers, and mitigates the potential rate shock for customers that transition from low to moderate income." D.P.U. 22-22, at 471-472.

2. Company Proposal

The Company states that to be consistent with the directives in D.P.U. 15-155, its low-income discount rate for electric customers should be reduced from 34.5 percent to 34.3 percent (Exh. Unitil-CGDN-1, at 74 (electric)). Nevertheless, the Company proposes to

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[223] G.L. c. 164, § 141 provides, in part:

> In all decisions or actions regarding rate designs, the department shall consider the impacts of such actions on … the use of new financial incentives to support energy efficiency efforts. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount.

increase the low-income discount rate for electric customers taking service under the Company's residential low-income rate schedule (i.e., Rate RD-2) from 34.5 percent to 40 percent (Exhs. Unitil-RBH-1, at 40-41 (electric); Unitil-CGND-1, at 74 (electric); Unitil-CGDN-5 (electric)). The Company also notes that its proposal is consistent with the 42 percent discount approved for NSTAR Electric in D.P.U. 22-22, recognizes the economic challenges its customers face, and addresses low-income customers' energy burdens (Exhs. Unitil-RBH-1, at 41 (electric); Unitil-CGND-1, at 74 (electric)). During the proceeding, the Company noted that the change in the low-income discount rate, if approved, would become effective July 1, 2024, but would not be reflected in the RAAF until January 1, 2025, which is the next scheduled RAAF change after the instant Order is issued (Exh. DPU 37-1 (electric)). The Company estimates a potential under-collection of $1,016,362 and associated carrying charges of $16,291 resulting from the increased low-income discount rate proposed distribution rates to be effective July 1, 2024, and the current RAAF (RR-DPU-39 & Att. 2).

Regarding outreach, the Company intends to inform customers and stakeholders of its proposed increase in the low-income discount rate through existing communications channels, such as on-bill messaging, and a customer-based email campaign, as well a one-page flyer to be provided to the Montachusett Opportunity Council in Fitchburg, with additional versions translated into Spanish and Portuguese (Exh. DPU 35-6 (electric)). Further, the Company explains that it will create a summary document for advertisement at town offices in which the Company serves electric customers, and in local community centers identified in coordination with Making Opportunities Count agency (Exh. DPU 51-6 (electric)). Finally, the Company notes that it will provide a rate case summary document, which will include key points about the low-income discount rate, to elected officials who may wish to have it available for relevant constituents and groups (Exh. DPU 51-6 (electric)).

3. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company did not provide sufficient support for the proposed change to the discount rate (Attorney General Brief at 85). Further, the Attorney General claims that the Company's reliance on the low-income discount rate approved for NSTAR Electric in D.P.U. 22-22 is misplaced, as the proposed discount rate does not meet the Department's objectives to explore a rate "that provides an equitable discount for customers, provides assistance for the most vulnerable customers, and mitigates the potential rate shock for customers that transition from low to moderate income" (Attorney General Brief at 85-86, citing D.P.U. 22-22, at 472).

Additionally, the Attorney General argues that although the Company asserts that customers in its service territory have higher energy burdens compared with the statewide average, the proposed discount rate is flat and therefore does not mitigate higher energy burdens experienced by the most challenged households (Attorney General Brief at 86). The Attorney General asserts that rather than continuing with a flat discount rate, a stratified or tiered discount rate would provide targeted energy affordability assistance to customers who need it the most (Attorney General Brief at 86).

The Attorney General recommends that the Department direct the Company to maintain its current discount rate and then file a proposed low-income discount rate consistent with a future decision in a recently opened Department proceeding, D.P.U. 24-15, that addresses energy affordability (Attorney General Brief at 87-88). If the Department declines to accept this recommendation, the Attorney General suggests that the Department direct the Company to file, within nine months of the date of the instant Order, a proposed low-income discount rate consistent with the directive in D.P.U. 22-22 (Attorney General Brief at 88).

b. DOER

DOER asserts that the Department should reject the Company's proposed increase in the low-income discount rate because the proposal does not sufficiently address energy burden and affordability and would shift revenue requirement from low-income customers to other customers (DOER Brief at 22-23; DOER Reply Brief at 11-12). DOER recommends that the Department direct the Company to propose a multi-tiered discount rate, consistent with the Attorney General's recommendation (DOER Brief at 21, 24; DOER Reply Brief at 13-14). DOER states that the Company's affiliated utility, UES in New Hampshire, offers such a rate that includes five tiers of discounts linked to the federal poverty level (DOER Brief at 22). Under UES' provision, discounts range between eight and 76 percent, and, according to DOER, are more specifically able to target the most in-need households when compared to the Company's proposed flat rate (DOER Brief at 22). Finally, DOER recommends that the Department continue to evaluate the Company's low-income discount proposal in the context of the Department's investigation into energy burden in D.P.U. 24-15 (DOER Brief at 21; DOER Reply Brief at 14).

c. Company

As noted above, the Company argues that its low-income discount rate proposal is consistent with relevant Department goals and with the 42 percent discount rate approved for

NSTAR Electric in D.P.U. 22-22 (Company Brief at 265-266; 378 (electric)). In response to the intervenors' arguments concerning a multi-tier discount rate, the Company supports a statewide investigation with all relevant stakeholders and, in this regard, notes that in D.P.U. 24-15, it has requested that the Department consider approving the New Hampshire tiered low-income discount rate paradigm where funds are collected from each EDC and aggregated into a statewide pool to disburse to customers consistent with their applicable tier (Company Brief at 265-267 (electric); Company Reply Brief at 69, citing D.P.U. 24-15, March 1, 2024 EDC/LDC Initial Comments at 23). The Company asserts that the intervenors' recommendations also should be rejected because there is no record in this case to support a multi-tiered discount and, if multi-tiered low-income rates were approved in the instant proceeding that differed from what may be approved in D.P.U. 24-15, it would likely cause customer confusion (Company Brief at 266-267 (electric); Company Reply Brief at 69). The Company also contends that potential equity issues could arise if low-income customers found themselves in a less beneficial position as a result of low-income discount rates approved in D.P.U. 24-15 (Company Reply Brief at 69).

4. Analysis and Findings

As noted above, the Department recently opened a proceeding to investigate energy burden, with a focus on energy affordability for residential ratepayers. D.P.U. 24-15, Vote and Order Opening Inquiry at 1. The Department determined that the new proceeding will enable it to consider improvements to the programs currently offered to address energy affordability, to ensure maximum participation in each of these programs, and to determine whether additional programs may further benefit residential ratepayers of the Commonwealth's EDCs and LDCs. D.P.U. 24-15, Vote and Order Opening Inquiry at 1. The Department expects that low-income discount rate offerings will be among the existing programs investigated in that docket to consider improvements. See D.P.U. 24-15, Vote and Order Opening Inquiry at 13-14. In the meantime, while our investigation and decision in D.P.U. 24-15 are pending, in this instance, we find the Company's proposed increase in the low-income discount for electric customers recognizes the economic challenges certain customers face, is reasonable, and should help lessen the energy burden on qualifying customers (Exhs. Unitil-RBH-1, at 41(electric); Unitil-CGND-1, at 74 (electric); Unitil-CGDN-5; DPU 3-1 (electric); DPU 3-2 (electric); DPU 7-73 (electric)). Therefore, the Department approves the Company's proposal to increase its electric low-income discount rate to 40 percent.

The Department recognizes that the revised low-income discount rate constitutes a meaningful bill discount for low-income customers, but we also are mindful of the impacts that increasing the discount rate may have for other customers, as costs associated with providing a low-income discount are recovered from all distribution customers. We recognize the need to balance the impact of increasing a low-income discount rate against the impact on other customers, particularly moderate-income residential and small C&I customers. While the Department finds that the adjustment to the low-income discount is reasonable at this time, the Department notes that further adjustments to the discount rate and framework (including possible implementation of a tiered structure) may be required in the future to provide equity for all customers. As noted above, the Department expects to address many of these issues as part of our investigation in D.P.U. 24-15. Following that investigation, the Department may direct additional modifications to the Company's low-income discount as appropriate.

The Company details several outreach initiatives to communicate the revised low-income discount to customers and relevant stakeholders, and we find these efforts to be reasonable and appropriate (Exhs. DPU 35-6 (electric); DPU 51-6 (electric)). In preparing future base distribution rate cases, the Department expects the Company to engage relevant stakeholders prior to filing to develop or enhance programs and rates designed to assist low-income customers in managing their energy bills. See, e.g., Order Establishing Tiering and Outreach Policy, D.P.U. 21-50-A at 35 (February 23, 2024) ("The Department's goal is to provide meaningful involvement of all people and communities with respect to the development, implementation, and enforcement of energy, climate change, and environmental laws, regulations, and policies and the equitable distribution of energy and environmental benefits and burdens … ."). The Company also shall employ quantitative analyses to assess the impacts of all proposed changes that could impact customer bills.

Finally, we address the Company's proposal to recover the costs associated with the increase to the low-income discount rate for electric customers in its next scheduled RAAF change on January 1, 2025 (Exh. DPU 37-1 (electric)). The Department finds the potential under-collection and carrying charges associated with delaying the inclusion of the increased low-income discount rate in the calculation of the RAAF is significant (RR-DPU-39 & Att. 2). Accordingly, the Department directs the Company to implement a RAAF that includes recovery of the estimated revenues associated with the approved low-income discount rate on the same date that the new discount rate takes effect, i.e., July 1, 2024. The Company shall provide an appropriate revised Residential Assistance Adjustment Clause tariff and Summary tariff as part of the compliance filing in this proceeding.

E. Heat-Pump Rates – Electric Division

1. Company Proposal

The Company states that it is fully committed to providing customers with cost-effective pathways to electrification (Exh. Unitil-RBH-1, at 38 (electric)). As such, the Company proposes new rate offerings for residential and low-income customers using heat pumps in support of its efforts to address strategic electrification, as well as its promotion of heat-pump technologies associated with its energy efficiency plans (Exh. Unitil-RBH-1, at 39 (electric)). The Company provided illustrative rate schedules for residential and low-income customers, respectively, for those customers with an eligible device that is used to heat or supplement another heat source for all or part of their home by transferring thermal energy from the outside with the use of a refrigeration cycle (proposed Schedule HP-RES; proposed Schedule HP-RES-LI).

The Company proposes a heat-pump rate structure that includes a fixed customer charge, a volumetric summer (i.e., May to October) kWh rate, and a volumetric winter (i.e., November to April) kWh rate (Exh. Unitil-JDT-1, at 24 (electric)). The proposed fixed monthly customer and summer volumetric kWh charges were set equal to those proposed for the Residential RD-1 rate (Exh. Unitil-JDT-1, at 24 (electric)). To determine the winter volumetric kWh charge, the Company conducted a revenue-neutral analysis (Exh. Unitil-JDT-1, at 24-25 (electric)). First, to determine an estimate of the additional kWh a residential customer would use after replacing a gas heating system with the installation of a heat pump, the Company assessed the normal use per customer for the Company's residential gas heating customers, and then converted such use into an equivalent winter kWh usage based on the efficiency of heat pumps (Exh. Unitil-JDT-1, at 24 (electric)). Then, using the estimated kWh in the winter period for a customer that replaced its gas heating system with heat pumps, the winter volumetric rate was set to recover the same level of total fixed costs to make the rate design revenue neutral to the Company (Exh. Unitil-JDT-1, at 24-25 (electric)). The proposed winter volumetric kWh rate for the heat-pump rate is 36 percent of the rate for the Residential RD-1 rate (Exh. Unitil-JDT-1, at 25 (electric)).

Unitil states that if the heat-pump rate is approved as filed, the Company anticipates that it will need six to nine months after issuance of this Order to complete system design, testing, and bill print (Exh. Unitil-JDT-1, at 25 (electric)). Further, Unitil states that it will promote awareness and adoption of the proposed heat-pump rate using an established framework for new rate offerings, including adding informational resources to the Company's website, a series of targeted messages utilizing direct-to-customer channels such as on-bill messaging and email campaigns, and geo-targeted social media outreach where available (Exhs. DPU 35-4 (electric); DPU 51-3 (electric)).

2. Positions of the Parties

a. Attorney General

In her initial brief, the Attorney General recommended that the Department reject Unitil's proposed heat-pump offerings because the Company had not demonstrated that the proposed rates appropriately balance the competing interests of supporting electrification and conservation goals, such as sending appropriate price signals to decrease load at the most expensive times of the day to delay or minimize investment costs, implementing cost-causation principles, and avoiding cost-shifting (Attorney General Brief at 88-89). The Attorney General noted that an

Interagency Rates Working Group ("IRWG")[224] had been convened to advance near- and long-term rate designs that align with the Commonwealth's decarbonization goals, and therefore the Department should delay approval of heat-pump rates until the IRWG completes its work (Attorney General Brief at 90). Alternatively, the Attorney General argued that the heat-pump rate should be approved only for those customers who have fully displaced all of their space heating appliances with heat pumps to incentivize customers to do full heating source displacements when doing installations, rather than some fraction thereof (Attorney General Brief at 90-91).

The Attorney General amended her position in the reply brief "in consideration of the Company's commitment to monitor and evaluate the efficacy and the impacts of the proposed rates, particularly the Company's commitment to monitor the pre-install and post-install energy usage of customers as well as how heat-pump conversions may contribute to rising costs" (Attorney General Reply Brief at 24, citing Company Brief at 378, 380-381 (electric)). The Attorney General now recommends that the Department approve the proposed heat-pump rates, provided the rates are (1) approved on an interim basis in recognition of the ongoing IRWG; and (2) limited to customers with heat-pump capacity sized to heat the customer's entire home, as defined by MassSave's standards for whole-home replacements (i.e., equipment sized to meet 90 to 120 percent of the total heating load at the outdoor design temperature pursuant to Air Conditioning Contractors of America Association, Inc. and American National Standards

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224 The IRWG was first convened in 2023, and includes representatives from the Executive Office of Energy & Environmental Affairs, DOER, the Massachusetts Clean Energy Center, and the Attorney General's Office (https://www.mass.gov/info-details/interagency-rates-working-group).

Institute, Manual J: Residential Load Calculation (2016)) (Attorney General Reply Brief at 24-27). The Attorney General contends the second condition will result in rates that are better targeted to what she claims is the policy goal for which the rates were designed, that is, to support heat-pump adoption in the Company's service territory (Attorney General Reply Brief at 26).

The Attorney General also recommends that the Department direct the Company to file a compliance filing after the proposed heat-pump rates have been in effect for 18 months that, at a minimum, should discuss (1) changes in pre install and post install energy usage following heat-pump conversion including summer usage for cooling, and (2) whether heat-pump conversions contribute to rising costs on the Company's system (Attorney General Reply Brief at 25). The Attorney General asserts that if warranted, based on the additional data and analysis conducted during the first 18 months the rate is available to customers, the Company should then propose revenue-neutral revised heat-pump rates, rather than waiting until the next base distribution rate proceeding to revise rates (Attorney General Reply Brief at 25-26).

Finally, the Attorney General does not support DOER's recommendation that the Department modify the Company's reconciling mechanism charges for heat-pump rate participants (Attorney General Reply Brief at 27). According to the Attorney General, the proposal is inconsistent with current reconciling mechanism structures and could result in higher revenue recovered from non-heat-pump customers (Attorney General Reply Brief at 27-28).

b. <u>DOER</u>

DOER asserts that the Department should approve the Company's proposed heat-pump rates, with certain modifications that will prioritize affordability and support electrification

(DOER Brief at 6-14; DOER Reply Brief at 2-4). In particular, DOER argues that the Department should direct the Company to revise its proposed heat-pump rate tariffs to include seasonal reconciling mechanisms (DOER Brief at 9-11; DOER Reply Brief at 2-3). To that end, DOER contends that the Company's revenue-neutral approach should be extended from the distribution charge to the Company's reconciling mechanisms to reduce operating costs of heat pumps in the winter season, avoid overcollection of revenues associated with those mechanisms, and remove a continued disincentive for customers to convert to electric heating (DOER Brief at 9-11; DOER Reply Brief at 2). DOER also claims that seasonal reconciling mechanisms will result in lower bills for residential customers using heat pumps and would provide the largest annual bill decrease for low-income customers on the rate (DOER Brief at 12-14, citing Exhs. Unitil-JDT-5, at 1-2 (Rev. 2) (electric); Unitil-RJA-4, at 1-4 (gas); RR-DOER-2, Att. 1). DOER asserts that the Company stated that it could charge a seasonal rate for reconciling mechanisms to collect a fixed level of revenue in a similar manner as its distribution charge (DOER Brief at 9, citing RR-DOER-2, Att. 1). According to DOER, excluding reconciling mechanisms from the heat-pump rate "significantly blunts the power of the rate to incentivize electrification" (DOER Reply Brief at 3).

DOER also argues that the Department should monitor and modify the heat-pump rate design, as necessary (DOER Brief at 18). DOER asserts that the Department can choose to review heat-pump rates for potential revisions as part of the annual reconciliation filings or separately (DOER Brief at 18; DOER Reply Brief at 3-4). DOER also recommends that the Company conduct robust marketing, education, and outreach on its heat-pump offerings (as well as its EV TOU rate) and report annually on customer participation as well as marketing and customer outreach measures[225] (DOER Brief at 15-17; DOER Reply Brief at 4-5).

Finally, DOER disagrees with the Attorney General's conditions for implementation of the heat-pump rate and contends that they represent a missed opportunity to incentivize electrification and minimize an increase in demand during the Company's peak hours (DOER Reply Brief at 5-7). DOER also contends that the proposed heat-pump rate's revenue-neutral distribution charge will prevent cost-shifting and provide a measure of protection for all other ratepayers (DOER Reply Brief at 8).

c. Company

The Company submits that its proposed residential heat-pump rate aligns with the Commonwealth's net-zero emissions target as well as the Company's 2022-2024 Energy Efficiency Plan (Company Brief at 364 (electric)). The Company contends that its objective in developing its proposed heat-pump rate was to balance the incentive for the heat-pump rate with the cost of service and minimize intra-class subsidization (Company Brief at 365 (electric)). According to the Company, its proposed heat-pump rate design attempts to achieve the equivalent fixed cost recovery from customers who are heating with heat pumps as the class average fixed cost recovery (Company Brief at 365 (electric)). Further, the Company asserts that its proposed heat-pump rate is intended to allow for heat-pump adoption while mitigating concerns related to possible increases in energy burden that could occur with associated higher

225 DOER argues that, at a minimum, the Company should report annually on: (1) its marketing efforts; (2) the number of customers enrolled on the heat-pump rates; (3) the pre- and post-usage for customers installing an air-source heat pump; and (4) all available time-interval data (DOER Brief at 16).

winter use (Company Brief at 379 (electric)). The Company contends that it will continue to monitor and evaluate the efficacy of the new heat-pump rate and propose any adjustments in its next base distribution rate proceeding (Company Brief at 379 (electric); Company Reply Brief at 65).

Regarding the Attorney General's reporting recommendations, the Company argues that the intervenors' proposed timelines provide insufficient time to gather useful data to present meaningful adjustments to the heat-pump rate design (Company Reply Brief at 65-66). Further, the Company rejects the Attorney General's proposal to limit the rate to customers with heat-pump capacity to heat their entire home (Company Reply Brief at 66). According to Unitil, such a proposal would be confusing, impractical, and burdensome to both the Company and customers (Company Reply Brief at 67-68).

In response to DOER's argument that Unitil should extend its revenue-neutral winter rate design for base distribution rates to reconciling mechanisms, the Company argues that there is no rationale for why customers should pay the same amount for a reconciling mechanism if their consumption increases or decreases (Company Brief at 380 (electric)). The Company notes that reconciling mechanisms are recovered on a per-kWh basis and not a customer or demand basis and as such the Department has determined that the amount a customer pays for these reconciling items should increase with increases in usage and decrease with decreases in usage (Company Brief at 380 (electric)). Regarding DOER's reporting recommendations, the Company contends that it has provided relevant information on its marketing efforts, the number of customers enrolled on the heat-pump rates, and the pre- and post-usage for customers installing an air-source heat pump (Company Brief at 381 (electric), citing Exhs. DPU 35-4 (electric);

DPU 51-3 (electric); AG 7-64 (electric); DOER 2-2). Further, the Company rejects the prospect of modifying the heat-pump rate design as part of the annual reconciliation filings (Company Brief at 382 (electric)). The Company asserts that the Department's review of reconciliation filings includes the costs and revenues associated with certain cost recovery mechanisms – the review is not the same as in rate design proceedings (Company Brief at 382 (electric)).

3. Analysis and Findings

Consistent with the Commonwealth's transition to clean energy, the Department supports customer conversion to electrified and decarbonized heating technologies, including heat pumps that transfer thermal energy from outside for use in interior structural heating. See, e.g., Three-Year Energy Efficiency Plans for 2022 through 2024, D.P.U. 21-120 through D.P.U. 21-129, at 230-231 (2022) (discussing statewide effort to encourage heat pumps). Increased use of heat pumps is a critical step toward the electrification of building thermal loads; however, all else equal, heat-pump usage can increase customer bills beyond the actual cost to serve due to the increased use in energy required to operate a heat pump. As such, we expect Massachusetts utilities to present proposals that appropriately balance the resulting rate impact with the intended benefits associated with heat pump use. We acknowledge the Company's initiative in proposing this rate, and we appreciate the concerns raised and recommendations provided by the Attorney General and DOER.

The Company's proposed heat-pump rate offerings reduce the variable kWh rate associated with electric use during the winter, when heat pumps would result in increased electricity use to displace fossil fuel heating equipment (Exhs. Unitil-JDT-1, at 24 (electric); proposed Schedule HP-RES; proposed Schedule HP-RES-LI)). The Department anticipates that this reduction in the variable kWh base distribution charge during the proposed winter period will better align heat-pump customers' bills with the costs to serve those customers. Further, the availability of a heat-pump rate for residential low-income customer classes is consistent with the important consideration that there should be policies and programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy and, in fact, benefit in the near-term from electrification opportunities. D.P.U. 20-80-B at 120. Thus, the Department finds the Company's proposal to be a reasonable, cost-efficient solution to mitigate the potential high bills associated with heat-pump implementation faced by residential and low-income customers within the context of current rate structures, while maintaining a rate structure that accurately reflects the cost to serve customers during this stage of electrification.

Based on these considerations, the Department approves a residential heat-pump rate available to all customers in rate classes RD-1 and RD-2 who install and use heat pumps in all or part of their home. We see no reason to delay the approval of this rate, as it is an important step in allowing customers to embrace alternative heating sources. Further, we decline to limit the rate offering only to customers with heat-pump capacity sized to heat their entire home, as suggested by the Attorney General (Attorney General Reply Brief at 26-27), as such a limitation could motivate potential heat-pump users to forgo installation.

The Department is not persuaded to accept DOER's recommendation of seasonal reconciling mechanisms (DOER Brief at 9-12; DOER Reply Brief at 2-3). In particular, we are not convinced that the proposed heat-pump rate design removes the incentive for customers to convert to electric heating. The rate proposal makes no change to any of the reconciling rate charges or basic service rate, which altogether comprise a significant portion of the total customer bill (see, e.g., RR-DOER-2, Att. 1). Rather, the Department finds that the rate proposal appropriately balances the competing goals of electrification and conservation at this stage of the energy transition in the Commonwealth.

The Department, however, agrees with the intervenors that monitoring and reporting on the progress of the heat-pump rate is essential. As such, the Department directs the Company to provide as part of its annual reconciliation filing the number of customers opting into (and off) the new tariffs, twelve months of pre- and post-installation monthly kWh use, and monthly peak kW use, if possible. The Company also shall include the number of customers, by rate class, opting into the heat-pump rate who received a rebate through the MassSave program, as well as the number of customers who received a rebate through the MassSave program but have not opted into the heat-pump rate.

In Section III.D.5.a. above, the Department approved a five-year PBR plan for the Company. During the term of the PBR plan, the Department expects increased electrification, decreased reliance on fossil fuels, deployment of AMI technology that can enable innovative rate design, technological advances, and electric distribution system investment. These factors, among others, could allow for the development of superior rate offerings. For the five-year term of the PBR plan, the Department finds that the Company's proposed heat-pump rate strikes an appropriate balance to help incentivize customers who have made efforts to electrify, while not removing the incentive to conserve energy. The Company, however, shall closely monitor the impact of the heat-pump rates, as well as progress towards increased electrification in the Commonwealth, and shall include an analysis and discussion in its next base distribution rate case regarding the successes, failures, and lessons learned from its heat-pump rate offering. In its next base distribution rate case filing, the Company shall propose necessary changes to the heat-pump rate offerings or propose alternative rate offerings designed to address electric home heating solutions.

As noted above, the Company will need six to nine months after issuance of this Order to complete system design, testing, and bill print (Exh. Unitil-JDT-1, at 25 (electric)). The Department directs the Company to file final tariffs at least 30 days prior to expected implementation of the new heat-pump rates, and to serve a copy of the tariffs on the Attorney General and DOER. There should be no fundamental changes in the final tariffs when compared to proposed Schedule HP-RES and proposed Schedule HP-RES-LI, so a 30-day time period should provide sufficient time to review the tariffs. During the next six to nine months, the Department expects Unitil to begin its outreach and education efforts to promote awareness of the new rate offerings including, but not limited to, using the Company's established framework for new rate offerings (Exhs. DPU 35-4 (electric); DPU 51-3 (electric)). The outreach and education efforts shall continue during the PBR term, and the Company shall report on the progress of such efforts in the annual reconciliation filings.

F. Revenue Decoupling – Electric Division

1. Introduction

On January 31, 2022, the Department issued a final Order approving the three-year energy efficiency plans for calendar years 2022 through 2024 ("2022-2024 Three-Year Plans") filed by the Company and others (collectively, "Program Administrators"),[226] subject to certain directives, disallowances, and program modifications. D.P.U. 21-120 through D.P.U. 21-129. The Department also made a general policy pronouncement regarding the future of full revenue decoupling for EDCs. D.P.U. 21-120 through D.P.U. 21-129, at 227-235. Specifically, the Department found that the Program Administrators' strategy of strategic electrification, as set forth in the 2022-2024 Three-Year Plans, potentially obviates the continued use of full revenue decoupling by the EDCs. D.P.U. 21-120 through D.P.U. 21-129, at 227.[227] The Department determined that recent changes in the Commonwealth's energy policies call into question the underlying premise supporting the Department's earlier implementation of full revenue

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226 In addition to Unitil's electric and gas division, the Program Administrators comprise The Berkshire Gas Company; Eversource Gas Company of Massachusetts; Liberty Utilities (New England Natural Gas Company) Corp.; Boston Gas; NSTAR Gas Company; the Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE; National Grid (electric); and NSTAR Electric.

227 The Department explained that it has allowed full revenue decoupling for each EDC and LDC since the passage of the Green Communities Act in 2008, having implemented revenue decoupling in base distribution rate proceedings. D.P.U. 21-120 through D.P.U. 21-129, at 227, citing D.P.U. 17-05-B at 219; D.P.U. 11-01/D.P.U. 11-02, at 113; D.P.U. 07-50-A at 31-32; D.P.U. 09-39, at 61-92. Full revenue decoupling separates a distribution company's revenues from all changes in consumption, regardless of the underlying cause of the changes, to remove the disincentives distribution companies historically faced regarding deployment of demand-reducing resources. D.P.U. 21-120 through D.P.U. 21-129, at 228, citing D.P.U. 07-50-A at 31. The Department was concerned that, without full revenue decoupling, distribution companies would not be able to fully embrace the successful implementation of demand-reducing measures and actions that became an essential component of the Commonwealth's strategy to mitigate the impact of increasing energy costs with the passage of the Green Communities Act in 2008. D.P.U. 21-120 through D.P.U. 21-129, at 228, citing D.P.U. 07-50-A at 33.

decoupling for EDCs. D.P.U. 21-120 through D.P.U. 21-129, at 229, citing An Act to Advance Clean Energy, St. 2018, c. 227; 2021 Climate Act. The policy shift allows Program Administrators to increase electricity consumption through the energy efficiency programs and requires the Program Administrators to drive acceptance of strategic electrification measures to achieve a minimum level of sustained GHG emission reductions. D.P.U. 21-120 through D.P.U. 21-129, at 229. Therefore, the Department determined that it would discontinue full revenue decoupling for EDCs, thereby ensuring that their business models would continue to align with the Commonwealth's energy and environmental policy goals. D.P.U. 21-120 through D.P.U. 21-129, at 231-232. In doing so, the Department sought to reorient the EDCs to no longer be neutral but, rather, to embrace increasing clean electric load. D.P.U. 21-120 through D.P.U. 21-129, at 232.

In announcing this policy change, the Department directed each EDC, in its next base distribution rate proceeding, to include for adjudication a rate proposal that provides for the discontinuance of full revenue decoupling. D.P.U. 21-120 through D.P.U. 21-129, at 234.[228] The Department recognized that removal of a full revenue decoupling mechanism comes before any increase in distribution sales from the strategic electrification efforts under the 2022-2024 Three-Year Plans, so the Department would take economic forecasts into account while also examining planned strategic electrification activities. D.P.U. 21-120 through D.P.U. 21-129,

[228] NSTAR Electric filed a base distribution rate case less than two weeks after the Department issued D.P.U. 21-120 through D.P.U. 21-129. D.P.U. 22-22, Petition for Approval (January 14, 2022). The Department ultimately determined that NSTAR Electric must file a proposal to eliminate full revenue decoupling in its next base distribution rate case. D.P.U. 21-120-B through D.P.U. 21-129-B at 21.

at 233-234, citing Statewide Plan, Exh. 1, App. C.l. - Electric (Rev.), Table IV.B.3.1. The Department also indicated that we may consider implementing a targeted decoupling mechanism[229] that achieves the Commonwealth's electrification goals and GHG emissions reduction goals as part of each company's next base distribution rate proceeding. D.P.U. 21-120 through D.P.U. 21-129, at 234 n.145, citing D.P.U. 07-50-A at 29-30.

The Attorney General filed a motion for reconsideration of the Department's decision to eliminate full revenue decoupling for EDCs and the directive that each EDC propose the elimination of full revenue decoupling in its next base distribution rate proceeding. D.P.U. 21-120-B through D.P.U. 21-129-B at 3-4, citing Attorney General Motion for Reconsideration at 3. The Attorney General argued that the Department should open a generic investigation to explore the future of revenue decoupling for EDCs with participation by all interested stakeholders. D.P.U. 21-120-B through D.P.U. 21-129-B at 3-4, citing Attorney General Motion for Reconsideration at 3-4. The Department denied the Attorney General's motion for reconsideration. D.P.U. 21-120-B through D.P.U. 21-129-B at 12-21. In reaffirming the directive for each EDC to file a proposal in its next base distribution rate case to eliminate full revenue decoupling, the Department noted that it would exercise its underlying mandate to regulate in the public interest in considering (a) the interests of ratepayers and the EDC and

229 In determining whether to approve a targeted revenue decoupling mechanism, the Department would consider service-territory specific factors, such as economic forecasts, the penetration of such technological initiatives as distributed generation and EV charging infrastructure, and company-driven and third-party-driven strategic electrification and energy efficiency efforts. D.P.U. 21-120-B through D.P.U. 21-129-B at 16 n.13.

(b) the priorities of the Commonwealth's energy and environmental policies. D.P.U. 21-120-B through D.P.U. 21-129-B at 21-22 n.16.

2. Company Proposal

Unitil did not propose to eliminate full revenue decoupling and instead proposes to maintain full revenue decoupling during its proposed PBR term (Exh. Unitil-RBH-1, at 32-37 (electric)). In support of its proposal, the Company states that although the current rate of residential and C&I implementation of electrification measures in its service area has been encouraging, it will take time for the increased load and revenue associated with electrification to offset the reduction in use and revenue brought about by energy efficiency measures (Exhs. Unitil-RBH-1, at 33-34 (electric); DPU 15-1, at 1 (electric)). Further, the Company cites the high concentration of older homes in its service area, which presents electrification conversion challenges (Exhs. Unitil-RBH-1, at 34 (electric); Unitil-RBH-Rebuttal at 9 (electric); DPU 15-1, at 1 (electric)). The Company also notes that the pace of electrification is impacted by affordability restrictions faced by the high proportion of low- and moderate-income residents in the service area (Exhs. Unitil-RBH-1, at 34 (electric); Unitil-RBH-Rebuttal at 9 (electric); DPU 15-1, at 1-2 (electric)). In sum, Unitil submits that electrification remains in the early stages in the Company's service area, and it is unclear how customer acceptance will unfold (Exhs. Unitil-RBH-1, at 35-36 (electric); DPU 35-7 (electric)).

Additionally, Unitil states that keeping full revenue decoupling in place is important to maintain the Company's credit profile and rating and, therefore, its access to, and cost of, capital (Exhs. Unitil-RBH-1, at 36-37, 47-50 (electric); DPU 15-1, at 2 (electric)). In particular, Unitil notes that in 2022 S&P Ratings raised the Company's New Hampshire affiliates' credit outlook from poor to stable in part because those operating companies were allowed decoupling mechanisms (Exh. Unitil-RBH-1, at 36-37, 49 (electric), citing S&P's Global Ratings, Research Update: Unitil Corp. Revises Outlook to Stable From Negative; Affirms Ratings at 1-2 (August 5, 2022); DPU 15-1, at 2 (electric)).

3. Positions of the Parties

Unitil argues that revenue decoupling is closely connected to the Company's success under its PBR plan, as it is necessary to maintain the appropriate revenue streams during the proposed five-year stay-out period to ensure that the Company has sufficient means to usher in the energy transition and is an integral component of maintaining the Company's financial integrity (Company Brief at 31-32 (electric)). Specifically, Unitil contends that the loss of the revenues provided under decoupling, without a corresponding increase in revenues due to electrification, will lead to a mismatch of revenues and capital costs incurred to advance the energy transition (Company Brief at 32 (electric), citing Exhs. DPU 15-1 (electric); DPU 35-7 (electric); Tr. 1, at 40-42, 48). Further, Unitil claims that the elimination of decoupling at a time when it is still unclear when and to what extent the Company's customers would electrify their residences and businesses will increase the Company's business and financial risk, which would ultimately negatively impact its financial profile (Company Brief at 32-33 (electric), citing Tr. 1, at 43-45, 51-53; Tr. 12, at 1172-1174; RR-AG-15).

According to the Company, there is a path forward to eliminating full revenue decoupling in the future, as revenues increase with the pace of electrification and the need to recover revenues through decoupling decreases (Company Brief at 33 (electric)). The Company argues that the rebalancing of revenues between increased kWh sales due to electrification and the corresponding reduction in the need to recover revenues through the RDM is consistent with the Department's approach to reviewing decoupling proposals (Company Brief at 34 (electric)). According to the Company, the Department would be exercising its mandate to regulate in the public interest by considering the interests of ratepayers and the EDC alongside the priorities of the Commonwealth's energy and environmental policies (Company Brief at 34, citing D.P.U. 21-120-B through D.P.U. 21-129-B at 21-22 & n.16). The Company contends that a gradual transition away from revenue decoupling protects the Company's and customers' interests and ensures that the Commonwealth's energy and environmental priorities and policies remain in the forefront (Company Brief at 34-35 (electric)). In this regard, the Company asserts that it has demonstrated a commitment to electrification and addressing affordability and customers' energy burdens in its service area (Company Brief at 36-44 (electric)). No other party addressed the elimination of full revenue decoupling on brief.

4. Analysis and Findings

As noted above, in evaluating the most recent 2022-2024 Three-Year Plans, the Department directed the EDCs, including the Company, to submit a proposal in their next base distribution rate case that provides for the discontinuance of full revenue decoupling. D.P.U. 21-120 through D.P.U. 21-129, at 234. During the proceeding, Unitil explained that because the Department recognized that the removal of the decoupling mechanism would come before any increase in distribution sales from strategic electrification and further that the Department would need to take into account EDC-specific economic forecasts and planned strategic electrification activities, the Company considered the Department's inquiry in the instant case as an investigation of how revenue decoupling would affect utility operations, customers, and the public interest (Exhs. Unitil-RBH-1, at 32 (electric); DPU 15-1, at 1, 2 (electric); Tr. 1, at 40-42). Thus, Unitil did not submit a proposal that provides for the elimination of full revenue decoupling, but instead explained why it considered it reasonable to continue full revenue decoupling (Exh. Unitil-RBH-1, at 32-37 (electric); Tr. 1, at 40-41).

The Company has shown a commitment to timely energy transition and increasing its electric load, as necessary, to achieve decarbonization objectives. In particular, Unitil reports an increase in electrification within its service territory to such an extent that the Company expended the budget approved in the most recent Three-Years Plans' Residential Sector New and Existing Buildings energy efficiency program offerings prior to the end of the plans' term (Exh. Unitil-RBH-1, at 32-34 (electric); Tr. 1, at 47-49). See also Fitchburg Gas and Electric Light Company, D.P.U. 21-127, Letter to the Department (May 3, 2024). The Company continues to implement its grid modernization investments previously approved by the Department (Exh. Unitil-RBH-1, at 37 (electric)). See, e.g., Second Grid Modernization; Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122 (2018). Further, the Company's ESMP filing details over $50 million in proposed capital spending over the next five years on capacity, extended grid modernization, reliability and resiliency, and customer facing investments. See, e.g., D.P.U. 24-12, Exh. UN-ESMP-1, at 154. Additionally, as discussed in Section XII.E. below, the Company proposed, and we approve, a heat pump rate for all customers in rate classes RD-1 and RD-2 who install and use heat pumps in all or part of their home. Finally, as discussed in Section III.D.5. above, the Department approves for Unitil's electric division a five-year PBR plan with a K-bar approach to capital spending. The Department expects under the PBR plan, the Company will continue to make important investments toward electrification and decarbonization in a way that addresses evolutions in energy technology, climate change policies, more stringent customer requirements, and a need for system resilience and security.

The Department recognizes that while the Company is making meaningful progress in meeting the Commonwealth's clean energy objectives, the timing and extent of widespread acceptance of electrification and decarbonization remain uncertain and can be affected by service-area specific factors (Exhs. Unitil-RBH-1, at 34-36 (electric); Unitil-RBH-Rebuttal at 9 (electric); DPU 15-1, at 1 (electric); DPU 35-7 (electric)). D.P.U. 21-120-B through D.P.U. 21-129-B at 16 n.13; D.P.U. 21-120 through D.P.U. 21-129, at 233-234. We acknowledge the Company's concerns and challenges regarding converting older structures within its service area to electricity and the potential affordability restraints relevant to the pace of strategic electrification given the economic demographics of the Company's customer base (Exhs. Unitil-RBH-1, at 34 (electric); DPU 15-1 (electric); Tr. 1, at 46-47).

The Department also recognizes that during the transition to electrification, it is important for Unitil to maintain a stable credit profile, as a credit downgrade could change the Company's risk profile and ultimately increase costs for customers (Exhs. Unitil-RBH-1, at 36-37, 49 (electric); DPU 15-1, at 2 (electric); Tr. 1, at 51-52). In this regard, we note the role of revenue decoupling in credit ratings analyses (Exhs. Unitil-RBH-1, at 36-37, 49; DPU 15-1, at 2 (electric); AG 1-11, Att. 1, at 4 (S&P Global Ratings, Research (March 25, 2020): "Unitil [Corp.] also benefits from electric and natural gas decoupling in Massachusetts"); Att. 3, at 5 (S&P Global Ratings, Ratings Direct (November 10, 2021): "Unitil [Corp.] also benefits from electric and natural gas decoupling in Massachusetts"); Att. 5, at 4 (S&P Global Ratings, Ratings

Direct (August 11, 2023): "Our assessment also incorporates the company's generally constructive regulatory framework […]. Over 80 [percent] of its total customer base is covered under decoupled rates, reducing the volumetric risk associated with electricity and natural gas sales"); Att. 6, at 6-7 (Moody's Investor Service, Credit Opinion (July 9, 2020): ("In Massachusetts, [the Company] uses a revenue decoupling mechanism for its electric and gas segments ... Decoupling insulates the utility's cash flow from fluctuations in its retail electric and gas sales, thus adding a higher level of stability and predictability, a credit positive"); Att. 10, at 2, 5-7 (Moody's Investor Service, Credit Opinion (August 25, 2022): "In the absence of decoupling mechanisms, lower than anticipated volumes can have a negative impact on Unitil's subsidiaries' cash flows"); Tr. 1, at 43-45, 51-54; Tr. 7, at 715.

Although our directives in D.P.U. 21-120 through D.P.U. 21-129, at 233-235, were clear and unambiguous regarding the requirement that each EDC include in its next base distribution rate proceeding a rate proposal for the discontinuance of full revenue decoupling, the record developed in this proceeding demonstrates the complexities associated with evaluating the continuing role of full decoupling mechanism as EDCs ramp up their implementation of strategic electrification in the interest of decarbonization. For the Commonwealth to meet its GHG reduction targets, both energy efficiency and strategic electrification will be necessary, and thus decoupling in some form will continue to play a prominent role. In this regard, the design and purpose of a decoupling mechanism will evolve over the various stages of the clean energy transition. At some point, for example, a full decoupling mechanism would potentially provide benefits to customers in the form of rate reductions to return to customers the excess revenues that EDCs can be expected to generate through implementation of appropriate electrification strategies. Unitil may be correct that gradually eliminating full revenue decoupling as the pace of electrification increases would be appropriate (Company Brief at 33 (electric)). Thus, while the Company technically failed to comply with our directives in D.P.U. 21-120 through D.P.U. 21-129, its failure triggered a necessary reconsideration of those directives, at least as applied to Unitil's particular circumstances.

Based on the above considerations, and in considering the interests of ratepayers, Unitil, and the Commonwealth's energy and environmental policies, the Department finds that it is reasonable and appropriate for the Company to maintain full revenue decoupling through the five-year PBR term.[230] We conclude that maintaining full revenue decoupling at this time properly balances the Company's demonstrated efforts to advance the Commonwealth's climate goals with the uncertainty surrounding the timing and extent of widespread acceptance of electrification and decarbonization alternatives. As the transition toward widespread electrification proceedings over the next five years, the Department will assess in the Company's next base distribution rate case whether revenue decoupling – full or targeted – is warranted.

G. Electric Rate-by-Rate Analysis

1. Introduction

The Department must determine on a rate-class-by-rate-class basis the proper level at which to set the customer charge and distribution charges for each rate class. D.P.U. 22-22, at 475; D.P.U. 17-05-B at 260. As noted above, the Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs

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[230] In this regard, we find that the current record does not support a targeted approach to revenue decoupling.

should be allocated on the basis of equalized rates of return. D.P.U. 22-22, at 473; D.P.U. 17-05-B at 260-261; D.T.E. 02-24/25, at 256. This allocation method satisfies the Department's rate design goal of fairness. D.P.U. 22-22, at 473; D.P.U. 17-05-B at 261. Nonetheless, the Department must balance its goal of fairness with its goal of continuity. D.P.U. 22-22, at 473-474; D.P.U. 17-05-B at 261. For this balancing, we have reviewed the changes in total revenue requirement by rate class and bill impacts by consumption level within rate classes. The rate design for each rate class is discussed in detail below.

The basic components of the Company's delivery service rates are: (1) the customer charge, which is a fixed amount per month; and (2) the distribution energy charge, which is an energy charge based on usage in kWh over the billing cycle. An additional component for C&I customers is a distribution demand charge in kilowatts ("kW") or kilovolts Ampere ("kVA"). The customer charge is intended to recover the fixed costs to serve a customer that do not vary with a customer's electricity use, such as the costs of billing and metering. Distribution energy charges are a function of a customer's use, and, therefore, impact a customer's bill in proportion to how much electricity the customer consumed in a given billing cycle. A distribution demand charge is intended to recovery capacity-related costs and is a function of a general service customer's highest monthly usage at a single point in time in the billing cycle.

2. Rates RD-1 and RD-2: Residential Delivery Service

a. Company Proposal

The Company's current residential Rate RD-1 is available for all domestic purposes at individual private dwellings and in individual apartments and in apartment or condominium buildings (proposed M.D.P.U. No. 398 (electric)). Service is also available for churches and farms at existing locations that received service under this rate prior to the effective date of the current tariff, though new load at these locations may not qualify (proposed M.D.P.U. No. 398 (electric)). The Company's current residential Rate RD-2 is available to any Rate RD-1 customer that shows verification of a low-income receipt of any means-tested public benefits, or verification of eligibility for the low-income home energy assistance program (proposed M.D.P.U. No. 399 (electric)). Currently, residential Rates RD-1 and RD-2 customers have a customer charge of $7.00 per month and a distribution energy charge of $0.07903 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)). The Company proposed to increase the customer charge to $8.50 per month and the energy charge to $0.10013 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)).

b. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for Rates RD-1 and RD-2 is $22.04 per month (Exh. Unitil-JDT-3, at 15 (Rev. 4) (electric)). As discussed in Section XII.C.3. above, the Department finds that a customer charge of $8.50 per month for Rates RD-1 and RD-2 best meets our rate design goals and objectives. Therefore, the Department approves a customer charge of $8.50 per month for Rates RD-1 and RD-2.[231] The Company shall set the volumetric energy charge for Rates RD-1 and RD-2 to recover the remaining class distribution revenue requirement approved in this Order.

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231 The total amount resulting from the billing of all charges under Rate RD-2 represents a discount versus the total amount under Rate RD-1.

3. Rates EV-RES: Residential EV Service

a. Company Proposal

The Company's current residential Rate EV-RES is limited to residential customers who require service restricted to charging a battery electric vehicle or plug-in hybrid electric vehicle via a recharging outlet at the customer's premises (proposed M.D.P.U. No. 403 (electric)). The Company's rate structure for this rate schedule, along with its current rates, were approved in Electric Vehicle Infrastructure Programs, D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 269-270 (2022); D.P.U. 21-92, Stamp-Approved Compliance Filing (June 22, 2023).

Currently Rate EV-RES has a customer charge of $6.39 per month and seasonal TOU base distribution, external transmission, and basic service charges. M.D.P.U. No. 312-24-C, Sheet 5 (electric). The Company proposed no change to its customer charge but proposed to annualize its TOU charges (Exh. Unitil-JDT-1, at 25-26 (electric)). Currently, there are three pricing periods: (1) off-peak, defined as Monday through Friday, 8:00 p.m. to 6:00 a.m., all day weekends, and weekday holidays; (2) mid-peak, defined as Monday through Friday, 6:00 a.m. to 3:00 p.m., excluding weekday holidays; and (3) on-peak, defined as Monday through Friday, 3:00 p.m. to 8:00 p.m., excluding weekday holidays (Exh. Unitil-JDT-7 (electric)). M.D.P.U. No. 312-24-C, Sheet 5 (electric). The base distribution charges are based on seasonal ratios to the otherwise applicable Rate RD-1 charges. D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 269-270. For the summer period, the off-peak ratio is 0.50, equal to $0.03951 per kWh; the mid-peak ratio is 1.43, equal to $0.11283 per kWh; and the on-peak ratio is 2.00, equal to $0.15835 per kWh. M.D.P.U. No. 312-24-C, Sheet 5 (electric). For the winter period the off-peak ratio is 0.50, equal to $0.03951 per kWh; the mid-peak ratio is 1.28, equal to

$0.10117 per kWh; and the on-peak ratio is 2.23, equal to $0.17645 per kWh. M.D.P.U. No. 312-24-C, Sheet 5 (electric).

To develop proposed annual ratios, the Company summed residential base distribution revenues for the test year for each time period, divided the results by the associated residential energy use, and then calculated off-peak, mid-peak, and on-peak base distribution charges (Exhs. Unitil-JDT-1, at 26 (electric); Unitil-JDT-7 (electric); Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab EV-RES Rate) (electric)). The Company then calculated the ratio of each of those rates to the otherwise applicable Rate RD-1, resulting in annualized ratios (Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab EV-RES Rate) (electric)). As a result, using the proposed residential Rate RD-1 base distribution energy charge of $0.10013 per kWh, the Company proposed a ratio of 0.50 for off-peak hours, 1.36 for mid-peak hours, and 2.11 for on-peak hours, resulting in proposed base distribution energy charges of $0.05006 per kWh, $0.13572 per kWh, and $0.21159 per kWh, respectively (Exhs. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Annual EV-RES) (electric); DPU 23-8, Att. (Supp.) (electric)). The Company performed a similar process to annualize ratios to apply to basic service and external transmission charges.

b. Analysis and Findings

In D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 269, the Department found the rate structure for Rate EV-RES to be reasonable and acceptable. Here, the Department finds the process used by the Company to annualize its ratios for the TOU portions of the Rate EV-RES to be reasonable and, therefore, we approve the Company's approach. The Department directs the

Company to calculate the annualized TOU rates for Rate EV-RES consistent with its proposed method and based on the otherwise applicable Rate RD-1 distribution energy charge.

4. Rate GD-1: Small General Delivery Service

a. Company Proposal

The Company's current Rate GD-1 is available at single locations to small C&I customers with non-residential loads consistently under four kW and energy consumption less than 850 kWh per month where the Company delivers electricity for the exclusive use of the customer and not for resale, except for charging use of separately metered EV charging stations (proposed M.D.P.U. No. 400, Sheet 1 (electric)).

Currently, Rate GD-1 customers have a customer charge of $10.00 per month and a distribution energy charge of $0.07850 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)). The Company proposed to increase the customer charge to $12.00 per month, and the energy charge to $0.10648 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)).

b. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for Rate GD-1 is $15.54 per month (Exh. Unitil-JDT-3, at 15 (Rev. 4) (electric)). The Department finds that a customer charge of $12.00 per month for Rate GD-1 best meets our rate design goals and objectives. Therefore, the Department approves a customer charge of $12.00 per month for Rate GD-1. The Company shall set the volumetric energy charge for Rate GD-1 to recover the remaining class distribution revenue requirement approved in this Order.

5. Rate GD-2: Regular General Delivery Service

a. Company Proposal

The Company's current Rate GD-2 is available at single locations to C&I customers with demands (excluding space heating and water heating loads eligible under Rate GD-5) consistently greater than or equal to four kW or energy consumption consistently greater than or equal to 850 kWh per month and generally less than 120,000 kWh per month where the Company delivers electricity for the exclusive use of the customer and not for resale, except for charging use of separately metered EV charging stations (proposed M.D.P.U. No. 400, Sheet 2 (electric)). Demand is measured as the highest 15-minute kW load determined during the month, but not less than any specified minimum available contract capacity, if applicable (proposed M.D.P.U. No. 400, Sheet 5 (electric)).

Currently, Rate GD-2 customers have a customer charge of $10.00 per month, a distribution demand charge of $9.81 per kW, and a distribution energy charge of $0.02377 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)). The Company proposed to increase the customer charge to $12.00 per month, increase the distribution demand charge to $10.00 per kW, and to decrease the distribution energy charge to $0.02264 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)).

b. Analysis and Findings

In performing its ACOSS, the Company grouped customers in Rates GD-2, GD-4, and GD-5 (Exhs. Unitil-JDT-1, at 10; Unitil-JDT-3, at 6 (Rev. 4) (electric)). The Company proposed no change to the target revenues for this rate group. The resulting embedded customer charge for this rate group is $44.41 per month and the embedded demand charge is $9.99 per kW, both of which are higher than the current respective charges (Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)). In addition, as shown in the Department's illustrative Schedule 10 for the electric division below, the target revenue for this rate grouping is higher than the current base distribution revenues and higher than the base distribution revenues in the Company's final revised ACOSS (Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)). The Department finds that a customer charge of $12.00 per month for Rate GD-2 best meets our rate design goals and objectives. The Department also finds the proposed demand charge of $10.00 per kW meets our cost-causation principles. Therefore, the Department approves a customer charge of $12.00 per month and a demand charge of $10.00 per kW for Rate GD-2. The Company shall set the volumetric energy rate for Rate GD-2 to recover the remaining class distribution revenue requirement approved in this Order.

6. Rate GD-3: Large General Delivery Service

a. Company Proposal

The Company's current Rate GD-3 is available for any industrial or large commercial customer (not participating in special contract rates) with energy consumption generally greater than or equal to 120,000 kWh per month where the Company delivers electricity for the exclusive use of the customer and not for resale, except for charging use of separately metered electric vehicle charging station (proposed M.D.P.U. No. 400, Sheet 2 (electric)). Service rates are differentiated by "on-peak" hours and "off-peak" hours (proposed M.D.P.U. No. 400 (electric)). On-peak hours are defined as 10:00 a.m. to 10:00 p.m. for all non-holiday weekdays, Monday through Friday (proposed M.D.P.U. No. 400, Sheet 2 (electric)). Off-peak hours are defined as 10:00 pm to 10:00 am during non-holiday weekdays and all-day for weekends, Saturday and Sunday, and all day for official federal and Massachusetts holidays that occur on a weekday (proposed M.D.P.U. No. 400, Sheet 2 (electric)). Demand is measured as the highest 15-minute integrated kVA load determined during the on-peak period of the month for which the charge is rendered, but not less than any specified minimum available contract capacity, if applicable (proposed M.D.P.U. No. 400, Sheet 5 (electric)).

Currently Rate GD-3 customers have a customer charge of $300.00 per month, a distribution demand charge of $8.07 per kVA, an on-peak distribution energy charge of $0.01952 per kWh, and an off-peak distribution energy charge of $0.00435 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)). The Company proposed to increase the customer charge to $338.75 per month, to increase the distribution demand charge to $9.75 per kVA, to increase the on-peak distribution energy charge to $0.02111 per kWh, and to increase the off-peak distribution energy charge to $0.00471 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)). The Company calculated the proposed distribution demand charge by performing an analysis similar to developing proposed customer charges (i.e., by calculating the rate at 150 percent of the overall system average distribution increase) (Exh. Unitil-JDT-1, at 20 (electric)). This calculation resulted in a distribution demand charge of $10.45 per kVA (Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rates) (electric)). The Company determined that a distribution demand charge of $9.75 per kVA was appropriate (Exh. Unitil-JDT-5, at 4 (Rev. 4) (electric)).

b. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for Rate GD-3 is $1,377.24 per month and the embedded demand charge is $11.04 per kVA (see

Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)). As noted above, the Company proposed a customer charge of $338.75 per month (Exh. Unitil-JDT-4, Sch. 2, at 1 (Rev. 4) (electric)). The Company demonstrated, however, that increasing the customer charge for Rate GD-3 by 150 percent of the overall system average increase would result in a customer charge of $388.34 (Exh. Unitil-JDT-5, at 3 (Rev. 4) (electric)). The Department finds a customer charge of $370.00 for Rate GD-3 customers brings it closer to the Company's proposed embedded unit cost of $1,377.24 per month (see Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)), and best balances cost causation with the rate design goal of continuity.

Further, since the embedded unit cost of demand as proposed is $11.04, the Department finds that a proposed increase in the distribution demand charge to $10.00 per kVA better meets our cost-causation principles. rather than the Company's proposed $9.75 per kVA (see Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rates) (electric)).

Therefore, the Department approves a customer charge of $370.00 per month for Rate GD-3 and a demand charge of $10.00 per kVA. The Company shall set the volumetric energy rates for Rate GD-3 to recover the remaining class distribution revenue requirement approved in this Order using the same method used to derive the proposed on-peak and off-peak distribution energy rates.

7. Electric Vehicle Demand Charge Alternative

a. Company Proposal

For customers under Rates GD-2 and GD-3, EV pricing is available, but not mandatory, to existing and new Level 2 and direct current fast charging EV station service locations for a period of ten years ending June 30, 2033, or a date determined by the Department (proposed

M.D.P.U. No. 400, Sheet 3 (electric)). EV charging station equipment includes charging ports, security lighting, networking, touch screens, component heating, charger fans, and cooling equipment, of which the aggregate load must be metered separately (proposed M.D.P.U. No. 400, Sheet 3 (electric)). Any non-EV charging general service usage at an EV charging site's service location must be separately metered and receive delivery service at the applicable general service rate (proposed M.D.P.U. No. 400, Sheet 3 (electric)). Existing customers will be assigned one of four available base distribution price schedules (i.e., Price Schedule A, B, C, or D) based on the load factor derived from Unitil's metered data based on the customer's twelve-month demand and energy usage if the Company has this information for the customer's account (proposed M.D.P.U. No. 400, Sheet 3 (electric)). Price Schedule A is for customers with load factors between zero and less than or equal to five percent; Price Schedule B is for customers with load factors greater than five percent but less than or equal to ten percent; Price Schedule C is for customers with load factors greater than ten percent but less than or equal to 15 percent; and Price Schedule D is for customers with load factors greater than 15 percent (proposed M.D.P.U. No. 400, Sheet 3 (electric)). Any existing customer without twelve months of demand and energy usage and all new customers will be assigned Price Schedule A, which represents the least load factor (proposed M.D.P.U. No. 400 (electric)).

On or before May 1st of each year, the Company will calculate the average load factor for each customer account based on the twelve-month average of the previous monthly bills' load factors (proposed M.D.P.U. No. 400, Sheet 3 (electric)). Based on the resulting average load factor, the Company shall place the customer on the appropriate price schedule for the upcoming twelve-month period (proposed M.D.P.U. No. 400, Sheet 3 (electric)). The four available price schedules are based on a sliding scale of base distribution demand charges and energy rates (proposed M.D.P.U. No. 400, Sheet 3 (electric)). Price Schedule D consists of the same demand charge and base distribution energy rate to which all non-EV pricing customers are subject (proposed M.D.P.U. No. 400, Sheet 3 (electric)). A customer, however, remains on EV pricing and is eligible for one of the other pricing schedules during the remaining term of EV pricing if the customer's average load factor decreases to 15 percent or less (proposed M.D.P.U. No. 400, Sheet 3 (electric)). The Company will continue to evaluate the customer's load factor for the duration of EV pricing (proposed M.D.P.U. No. 400, Sheets 3-4 (electric)).

The proposed customer charges for customers taking service on the EV demand charge alternative are the same proposed customer charges for the non-EV Rates GD-2 and GD-3, \$12.00 and \$338.75 per month, respectively (see Exh. DPU 23-8, Att. (Supp.) (electric)). The current and proposed base distribution charges for Rates GD-2 and GD-3 customers taking service under the EV demand charge alternative are as follows:

		Current $ / kWh	Current $ / kW	Proposed $ / kWh	Proposed $ / kW
GD-2	**Price Schedule A**	0.05976	-	0.05991	-
	Price Schedule B	0.05077	2.45	0.05059	2.50
	Price Schedule C	0.04178	4.90	0.04127	5.00
	Price Schedule D	0.02377	9.81	0.02264	10.00
GD-3	**Price Schedule A**	On-peak: 0.03990 Off-peak: 0.02473	-	On-peak: 0.04372 Off-peak: 0.02732	-
	Price Schedule B	On-peak: 0.03482 Off-peak: 0.01965	2.01	On-peak: 0.03808 Off-peak: 0.02168	2.43
	Price Schedule C	On-peak: 0.02972 Off-peak: 0.01455	4.03	On-peak: 0.03242 Off-peak: 0.01602	4.87
	Price Schedule D	On-peak: 0.01952 Off-peak: 0.00435	8.07	On-peak: 0.02111 Off-peak: 0.00471	9.75

(Exh. DPU 23-8, Att. (Supp.) (electric)). M.D.P.U. No. 312-24-C at 5 (electric).

a. Analysis and Findings

In D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 246-247, the Department approved the Company's method for developing demand alternative charges for Rates GD-2 and GD-3 customers. The Company is not proposing a change to this method at this time (Exh. Unitil-JDT-8 (Rev. 4) (electric)). Therefore, the Department directs the Company to apply the approved method to the final revenue requirement in this case to derive energy and demand charges, and to apply the customer charges as approved for Rates GD-2 and GD-3, i.e., $12.00 and $370.00, respectively.

8. Rate GD-4: Optional General Delivery Time-of-Use

a. Company Proposal

The Company's proposed Rate GD-4 is available for existing customers at existing locations that received service under this rate prior to March 1, 2008 (proposed M.D.P.U. No. 400, Sheet 4 (electric)). On-peak and off-peak periods are proposed to be the same as those defined under the Rate GD-3 (proposed M.D.P.U. No. 400, Sheet 4 (electric)). Demand is measured as the highest 15-minute kW load determined during the month, but not less than any specified minimum available contract capacity, if applicable (proposed M.D.P.U. No. 400, Sheet 5 (electric)).

Currently, Rate GD-4 customers have a customer charge of $10.00 per month, a distribution demand charge of $3.92 per kW, an on-peak distribution energy charge of $0.01027 per kWh, and an off-peak distribution energy charge of $0.00223 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 2 (Rev. 4) (electric)). In its initial filing, the Company proposed to increase the customer charge to $12.00 per month, the demand charge to $4.75 per kW, the on-peak distribution energy charge to $0.01355 per kWh, and the off-peak distribution energy charge to $0.00294 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 2 (electric)). During the proceeding, the target revenue for the entire rate grouping decreased to equal the current revenue requirement, and the Company proposed to maintain the current customer charge, distribution demand charge, and distribution energy charges (Exh. Unitil-JDT-4, Sch. 2, at 2 (Rev. 2) (electric)).

b. Analysis and Findings

As noted above, in performing its ACOSS, the Company grouped customers in Rates GD-2, GD-4, and GD-5 (Exhs. Unitil-JDT-1, at 10; Unitil-JDT-3, at 6 (Rev. 4) (electric)). The Company proposed no change to the target revenues for this rate group. The resulting embedded customer charge for this rate group is $44.41 per month and the embedded demand charge is $9.99 per kW (see Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)). In addition, as shown in the Department's illustrative Schedule 10 for the electric division below, the target revenue for this rate grouping is higher than the current base distribution revenues and higher than the base distribution revenues in the Company's final revised ACOSS (Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)). The Department finds that the Company's initially proposed customer charges and demand charges for Rate GD-4 best meets our rate design goals and objectives. Therefore, the Department directs the Company to implement a customer charge of $12.00 per month and a demand charge of $4.75 per kW. The Company shall set the volumetric energy rates for Rate GD-4 to recover the remaining class distribution revenue requirement approved in this Order using the same method used to derive the proposed distribution energy rates.

9. Rate GD-5: Water and/or Space Heating Delivery Rider

a. Company Proposal

The Company's proposed Rate GD-5 is restricted to customers currently receiving service on this rate or having a building permit as of May 1, 1985 (proposed M.D.P.U. No. 400, Sheet 4 (electric)). If a customer has installed, and uses in regular operation throughout the entire year, a Company-approved electric water heater that supplies the customer's entire water heating requirements, and/or a customer has permanently installed electric space heating equipment for five kW or more, the customer may elect to have this service metered separately according to a defined billing structure (proposed M.D.P.U. No. 400, Sheet 4 (electric)). The separate metering option, when selected, applies for at least twelve months (proposed M.D.P.U. No. 400, Sheet 4 (electric)).

Under the Company's proposal, space heating customers will be subject to a separate minimum charge of $8.00 per year per kW of installed space heating capacity (proposed M.D.P.U. No. 400, Sheets 4-5 (electric)). This provision applies for both electric heating and electric cooling where the two services are combined by the manufacturer in a single, self-contained unit (proposed M.D.P.U. No. 400, Sheet 5 (electric)).

Currently, Rate GD-5 customers who are not metered separately have no customer charge and a distribution energy charge of $0.06071 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 2 (Rev. 4) (electric)). In its initial filing, the Company proposed to increase the distribution energy charge to $0.07037 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 2 (electric)). The Company subsequently updated its proposal to maintain the current distribution energy charge of $0.06071 per kWh (Exh. Unitil-JDT-4, Sch. 2, at 2 (Rev. 4) (electric)).

b. Analysis and Findings

As noted, in performing its ACOSS, the Company grouped customers in Rates GD-2, GD-4, and GD-5 (Exhs. Unitil-JDT-1, at 10; Unitil-JDT-3, at 6 (Rev. 4) (electric)). The Company proposed no change to the target revenues for this rate group. The resulting embedded customer charge for this rate group is $44.41 per month and the embedded demand charge is $9.99 per kW (Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)). In addition, as shown in the

Department's illustrative Schedule 10 for the electric division below, the target revenue for this rate grouping is higher than the current base distribution revenues and higher than the base distribution revenues in the Company's final revised ACOSS (Exh. Unitil-JDT-3, at 14-15 (Rev. 4) (electric)). Therefore, the Department directs the Company to develop a distribution energy charge designed to recover the class distribution revenue requirement approved in this Order.

10. Rates SD and SDC: Outdoor Lighting Delivery Services

a. Company Proposal

Rate SD is available to all customers for outdoor lighting delivery service using company-owned equipment with the Company's standard lighting fixtures mounted on existing poles unless otherwise noted in the tariff (proposed M.D.P.U. No. 401 (electric)). Rate SD customers are charged based on the monthly kWh per luminaire as noted in the tariff, with nominal wattage and monthly kWh in the tariff (proposed M.D.P.U. No. 401(electric)).

Rate SDC is available to any municipal city or town, governmental entity, or other public authority for outdoor lighting delivery service with customer-owned equipment with the Company's standard lighting fixtures mounted on existing poles, except as otherwise noted in the tariff (proposed M.D.P.U. No. 402 (electric)). Currently Rate SDC customers have a distribution energy charge of $0.06429 per kWh (Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rate Design Lighting) (electric)). The Company proposed to increase the distribution energy charge to $0.08322 per kWh (Exh. Unitil-JDT Rate Design Model Electric (Rev. 4) (Excel, tab Rate Design Lighting) (electric)). Additional proposed changes with respect to rates and pricing under these rate schedules are discussed in Section XIII.F. below.

b. Analysis and Findings

The Department has reviewed the Company's proposed changes for calculating streetlighting rates. The Department finds that the proposed rate design for both Company-owned and customer-owned streetlights is reasonable and meets our rate design goals and objectives, and therefore, is approved. In addition, the Department approves the rate design for streetlighting using the method proposed by the Company and directs the Company to set the volumetric rate for Rate SDC to recover the class distribution revenue requirement approved in this Order.

H. Gas Cost Allocation

1. Introduction and Company Proposal

Unitil performed an ACOSS for its gas division to assign to each of its rate classes the cost for each component of the Company's overall cost of service based on cost incurrence (Exhs. Unitil-RJA-1, at 10 (gas); Unitil-RJA-4, at 3 (Rev. 4) (gas)). The Company assigned costs to each rate class based on one of the following methods: (1) direct assignment (e.g., test-year revenues); (2) a special study, as is done with meters and services, designed to replicate the intended use of a specific plant investment or expense and then assign that cost based on the specific use of that asset in the test year; and (3) the ACOSS procedures described below (Exh. Unitil-RJA-1, at 14-20 (gas)).

The Company's ACOSS procedures entail three primary steps: (1) functionalization; (2) classification; and (3) allocation (Exhs. Unitil-RJA-1, at 19 (gas); Unitil-RJA-4, at 4-5 (Rev. 4) (gas)). The Company functionalized and assigned costs to (1) production; (2) distribution; (3) customer services; (4) on-site and metering; and (5) gas supply

(Exhs. Unitil-RJA-1, at 14-15 (gas); Unitil-RJA-4, at 18-20 (Rev. 4) (gas)). Next, the functionalized costs elements were classified as: (1) demand-related; (2) commodity-related; and (3) customer-related (Exh. Unitil-RJA-4, at 3-4 (Rev. 4) (gas)). Specifically, with respect to distribution mains, the Company states that they are installed to meet both system peak period load requirements and to connect customers to the utility gas system (Exh. Unitil-RJA-1, at 21 (gas)). Thus, to classify main investments between customer-related and demand-related, the Company used an MSS, which was intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers (Exh. Unitil-RJA-1, at 23 (gas)). As part of the MSS, the Company assumed that minimum-sized distribution mains were 1.25-inch diameter plastic pipe, with adjustments made to accommodate its load carrying capacity (Exhs. Unitil-RJA-1, at 24 (gas); Unitil-RJA-4, at 8 (Rev. 4) (gas)). Based on the results of the MSS, the Company's ACOSS classified 42.9 percent of the investment in distribution mains as customer-related and 57.1 percent as demand-related (Exhs. Unitil-RJA-1, at 24 (gas); Unitil-RJA-4, at 8-9 (Rev. 4) (gas)). Additionally, the Company states that it explicitly excluded from the ACOSS all gas commodity-related revenues and expenses recovered through the Company's Cost of Gas Adjustment Charge (Exh. Unitil-RJA-1, at 26 (gas)).

The final step in the ACOSS process was cost allocation. In this step, the Company used internal and external allocation factors to allocate the functionalized and classified costs to customer rate classes based on cost-causation principles (Exhs. Unitil-RJA-1, at 13-14 (gas); Unitil-RJA-4, at 6 (Rev. 4) (gas)).

After completing the ACOSS steps, the Company calculated the revenue deficiency (Exh. Unitil-RJA-1, at 26-28 (gas)). Since costs associated with special contracts were not specifically identified and therefore assigned to all classes, special contract revenues were credited to all customer groups by including them in Other Revenues, resulting in a total revenue deficiency of $11,227,825 (Exh. Unitil-CGDN-7, at 1 (Rev. 4) (gas)).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that distribution mains represent nearly $71 million, or 60 percent, of the Company's $118 million total test-year gas division rate base (Attorney General Brief at 91, citing Exh. AG-DED-1, at 107). Consistent with arguments raised for Unitil's electric division, the Attorney General argues that Unitil's gas division ACOSS is flawed because it used an MSS to classify distribution main investments between customer-related and demand-related investments (Attorney General Brief at 92). According to the Attorney General, for the gas division ACOSS: (1) the Company's use of the MSS to classify costs associated with distribution mains is inconsistent with cost-causation principles, as the MSS methodology has been criticized by knowledgeable experts who deem it poorly conceived and fundamentally flawed; (2) regulatory history indicates that "many" other jurisdictions have already rejected the use of MSS; and (3) the Department's precedent is to use the proportional responsibility ("PR") cost allocation method, which considers relative system usage during all twelve months, not only during periods of system constraint (Attorney General Brief at 91-93, citing Exh. AG-DED-1, at 80; D.P.U. 17-170, Exh. NG-PP-1, at 32; D.P.U. 10-55, at 535).

The Attorney General argues that regulatory history supports the recognition of both demand and volumetric components in natural gas pipeline rates (Attorney General Brief at 92 citing Exh. AG-DED-1, at 120). Additionally, the Attorney General notes that Dr. James

Bonbright[232] criticizes the reliance on assumptions devoid of empirical data substantiation, and states that categorizing expenses linked to a minimum-sized distribution system established via an MSS is indefensible (Attorney General Brief at 79-80; Attorney General Reply Brief at 20, citing Exh. AG-DED-1, at 78). Furthermore, the Attorney General claims that FERC and its predecessor, the Federal Power Commission, historically recognized the joint volumetric and demand function of natural gas pipelines, which roughly correspond to on-peak and off-peak utilization of the system (Attorney General Brief at 92).

The Attorney General also rejects the Company's suggestion of widespread acceptance of the MSS (Attorney General Brief at 92-93). The Attorney General notes that the Company's survey provides 26 examples of utility rate cases with cost allocation based on a customer component of distribution mains (Attorney General Brief at 93, citing Exh. Unitil-RJA-Rebuttal at 18 (gas)). According to the Attorney General, this figure represents only 16.5 percent, or 26 out of 147, natural gas investor-owned distribution utilities currently operating across the United States (Attorney General Brief at 92-93 citing Exhs. AG-DED-1, at 106; Unitil-RJA-Rebuttal at 18 (gas)).[233] Further, the Attorney General contends that the survey

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232 Dr. James C. Bonbright is known for his contributions to public utility regulation and rate design. The Department's rate structure goals of efficiency, simplicity, continuity, fairness, and earnings stability, often referred to as the "Bonbright Principles," are an adaptation of, and attributed to, Principles of Public Utility Rates (1961) by James C. Bonbright, Albert L. Danielson, and David R. Kamerschen. D.P.U. 19-120, at 416 n.204.

233 The Attorney General asserts that the Company lists Illinois as one of the jurisdictions having recognized a customer component to the classification of distribution mains; the Attorney General argues, however, that the Illinois Commerce Commission rejected such a proposal in a recent rate case decision (Attorney General Brief at 93, citing Exh. AG-DED-Surrebuttal-1, at 19).

conflates the MSS approach with other equally erroneous approaches to classify a portion of distribution main costs as customer-related (Attorney General Brief at 93, citing Exh. Unitil-RJA-Rebuttal at 19 (gas)). The Attorney General claims that if the Company's survey is narrowed to include only the use of an MSS, the results show 16 examples of jurisdictions having approved an MSS approach (Attorney General Brief at 93, citing Exh. Unitil-RJA-Rebuttal at 19 (gas)).

Based on these arguments, the Attorney General asserts that the Department should reject the Company's proposed use of an MSS in its ACOSS and the resulting classification of distribution mains (Attorney General Brief at 93). Instead, the Attorney General urges the Department to rely on an ACOSS that aligns with the Atlantic Seaboard cost allocation ("Seaboard") approach,[234] which assigns costs associated with the Company's distribution mains based on a classification of these assets as 50 percent demand-related and 50 percent commodity-related (Attorney General Brief at 93, citing Exhs. AG-DED-1, at 110; AG-DED-3, Sch. 20).

b. Company

Unitil argues that using an MSS method for cost allocation is appropriate, justified, and consistent with the principles of cost causation and operational efficiency (Company Brief at 303 (gas); Company Reply Brief at 62). In particular, the Company contends that its minimum-sized unit approach for its ACOSS was grounded in the engineering considerations specific to the

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[234] The Seaboard method stems from a 1952 Federal Power Commission ruling establishing appropriate cost allocations for the Atlantic Seaboard natural gas pipeline. Re Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Docket No. 11. F.P.C. 43 (1952).

installation of distribution mains to serve its gas customers (Company Brief at 303 (gas); Company Reply Brief at 62, citing Exh. Unitil-RJA-Rebuttal at 6 (gas)).

Further, the Company claims that leading utility publications relied upon to conduct an ACOSS describe MSS concepts and methods as appropriate techniques for determining the customer component of utility distribution facilities (Company Brief at 303 (gas), citing Electric Utility Cost Allocation Manual, by John J. Doran et al., NARUC, and Gas Rate Fundamentals, AGA). In particular, the Company notes that according to the NARUC Manual, when a utility installs distribution plant to provide service to a customer and to meet a customer's peak demand requirements, the utility must classify distribution plant costs separately into demand-related and customer-related costs (Company Brief at 303 & n.96 (gas), citing NARUC Manual at 90 (1992 edition)). The Company dismisses the Attorney General's "selective" reliance on other academic literature, and notes that the same literature suggests that total costs of a utility's business is a function of the output of all costs related to this capacity, and that the vast majority of utilities use some form of an MSS to classify costs (Company Brief at 304 (gas); Company Reply Brief at 62, citing Principles of Public Utility Rates, Second Edition, 492 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988). Moreover, the Company contends that its survey of other jurisdictions provides an illustration that 26 utilities rely on this method, rather than a comprehensive study of methods employed by all the gas investor-owned utilities (Company Brief at 307 (gas)). The Company claims, however, that the Attorney General also has not conducted a comprehensive survey of utilities that use the MSS approach, and thus her references to decisions in other jurisdictions are not persuasive absent proper details and context (Company Brief at 307 (gas); Company Reply Brief at 62).

Additionally, Unitil argues that the PR method is a strictly volumetric approach using normalized monthly sales by rate class and computing the ratio of each rate class's monthly sales volumes to the total monthly sales volumes (Company Brief at 306 (gas), citing Exh. Unitil-RJA-Rebuttal at 24 (gas)). The Company contends that this approach has not been included in any utility academic or authoritative literature, and has found only limited acceptance in the past, including in Massachusetts (Company Brief at 306-307 (gas), citing Exh. Unitil-RJA-Rebuttal at 24-25 (gas)). Further, the Company claims that in such limited use, the PR method has included a customer-related element of the distribution system analogous to the proposed MSS method to represent facilities required to provide local service to customers (Company Brief at 305 (gas)). Finally, the Company argues that the Seaboard approach recommended by the Attorney General is essentially a cost-classification method and has been the subject of sharp criticism, particularly the requirement that capacity costs be distributed equally between the commodity and demand charges instead of being assigned exclusively to demand (Company Brief at 305-306 & n.101, 102 (gas), citing Alfred E. Kahn, Economics of Regulation: Principles and Institutions at 98-100 (June 1988); Stanislaw H. Wellisz, "The Public Interest in Gas Industry Rate Structures," Part II, Public Utilities Fortnightly 70 (August 2, 1962): 145-156; Homer R. Ross, "How Practical Is The Seaboard Formula?" (January 3, 1963): 26-34.). Based on these considerations, the Company asserts that using the MSS approach with a customer component, specifically for distribution mains, is fully supportable and commonly used, as opposed to the Seaboard and PR methods (Company Brief at 307 (gas)).

3. Analysis and Findings

The Department requires that cost allocation methods be driven by cost-causation principles. D.P.U. 17-170, at 318-319; D.P.U. 11-01/D.P.U. 11-02, at 320; D.P.U. 10-114, at 187; D.P.U. 10-55, at 534. In the instant case, the Department has weighed the competing cost allocation methods proposed by the Company and the Attorney General (Exhs. Unitil-RJA-1, at 18-29 (gas); Unitil-RJA-4 (gas); Unitil-RJA-Rebuttal at 5-26 (gas); Unitil-RJA-2R (gas); AG-DED-1, at 104-110; AG-DED-3, Schs. 19 through 22; AG-DED-Surrebuttal-1, at 17-26; AG-DED-Surrebuttal-2, Schs. 2, 3). We are persuaded that the Seaboard approach is the method most consistent with our cost-causation principles. The Seaboard method for allocating distribution costs recognizes that natural gas pipeline assets are built to supply both peak and non-peak service, and thus perform a demand function as well as an energy function by facilitating the ongoing delivery of natural gas (Exh. AG-DED-1, at 108-109 & n.236, citing Re Atlantic Seaboard Corporation and Virginia Gas Transmission Corporation, Docket No. 11. F.P.C. 43 (1952)).[235] This dual classification ensures that costs are distributed in a manner that accurately mirrors the practical use of these assets. The Department recognizes that the Seaboard approach aligns with the principles of cost causation by accurately reflecting the dual nature of the distribution mains. Further, by acknowledging the variable nature of gas usage among different customer classes and taking into account the volume of gas consumed, the

235 The Department notes that use of the Seaboard approach to classify production plant was rejected nearly 40 years ago in D.P.U. 84-145-A at 144-145. Given that this decision was rendered prior to the gas industry's unbundling and addressed production plant, we find it inapplicable to our analysis in the instant proceeding. Previously, the Department approved the use of the Seaboard method to allocate gas transmission and distribution plant. Haverhill Gas Company, D.P.U. 1115, at 53-54 (1982).

Seaboard approach considers a fair allocation of the costs to serve various customers and customer classes.

The Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 19-120, at 412; D.P.U. 17-170, at 316-317; D.P.U. 14-150, at 371; D.P.U. 13-75, at 333. The Seaboard method uses elements of the PR method that, as the Company notes, the Department has accepted in the past (Exh. Unitil-RJA-Rebuttal at 24-25 (gas)). See, e.g., D.P.U. 92-111, at 297-299; D.P.U. 87-59, at 95-96. The PR method is designed to allocate costs based on each class's utilization of distribution mains throughout the year, and not just during the system peak design day (Exh. AG-DED-1, at 109). The PR method recognizes that failure to consider customer use during non-peak periods over-allocates costs to low load-factor customers whose use is weather-sensitive (Exh. AG-DED-1, at 109). Similarly, by classifying a portion of distribution main assets as providing commodity service throughout the year, the Seaboard method addresses any potential over-allocation to rate classes by recognizing that distribution main assets serve both peak demand and continuous commodity service (Exh. AG-DED-1, at 110). This balanced approach avoids unfairly burdening rate classes with high peak usage, reflecting the dual role of the mains and promoting a more equitable rate structure (Exh. AG-DED-1, at 7). We also find that the Seaboard method is simple to apply and transparent in its application because it uses clear, straightforward principles to allocate costs. By classifying distribution main assets as 50 percent demand-related and 50 percent commodity-related, the methodology ensures a fair distribution of costs and an easily understood framework.

The Department is not convinced that the Company's proposed use of an MSS will ensure that costs are allocated appropriately in this case. According to Unitil, the concept of using an MSS approach for classifying distribution mains simply reflects the fact that the average customer served by the Company requires a minimum amount of mains investment to receive such service (Exh. Unitil-RJA-1, at 25 (gas)). Thus, the Company maintains that it is appropriate to conclude that the number of customers served represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers (Exh. Unitil-RJA-1, at 25 (gas)). The Department is concerned that the MSS, which we note has not been approved for use in any recent gas base distribution rate proceedings, may not fully capture cost causation by overlooking other factors that contribute to system costs, such as volumetric usage.

In this regard, we are not persuaded by the notion that most distribution main assets are utilized simply to connect customers to the distribution system; rather, we find that they also serve commodity and demand functions (Exhs. AG-DED-1, at 106; Unitil-RJA-Rebuttal at 8, 11).[236] As a result, we conclude that classification that is a composite of demand and commodity allocation factors is more appropriate for distribution main assets than a customer allocation factor.

Finally, we note that both the Company and the Attorney General commented on the use of an MSS by utilities in other jurisdictions (Company Brief at 307 (gas); Company Reply Brief at 62; Attorney General Brief at 92-93). The Department recognizes that the information

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236 As we note in Section XII.B.3. above the premise that a customer would be connected to, but not served by, the distribution system strikes us as unrealistic.

provided by the Company was illustrative, and not intended to be a comprehensive survey of all gas distribution utilities (Exhs. Unitil-RJA-Rebuttal at 18; Unitil-RJA-2R). Therefore, while informative, the Department finds that the survey results provided by the Company are insufficient to provide a comprehensive understanding of the regulatory landscape and assessments regarding the use of MSS in other jurisdictions.

Based on the above considerations, the Department finds that, in the instant proceeding, it is reasonable and appropriate for the Company to incorporate volumetric considerations in addition to peak considerations into its ACOSS for distribution mains. Further, we accept the Attorney General's recommendation to classify distribution mains as 50 percent demand-related and 50 percent commodity-related (Exhs. AG-DED-1, at 107-110; AG-DED-3, Sch. 20; AG-DED-Surrebuttal-1, at 22-23; AG-DED-Surrebutal-2, Sch. 2). The Department's approval of the Seaboard approach is based on its alignment with the principles of cost causation and the accurate reflection of the cost for the service that distribution mains provide. Accordingly, we direct the Company in its compliance filing to revise its ACOSS to use the Seaboard approach to allocate distribution mains and include all the adjustments to the cost of service approved herein. The Department has evaluated the remainder of Unitil's ACOSS for its gas division, and we find that it is reasonable and consistent with our ratemaking goals.

I. Marginal Cost Study – Gas Division

1. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 15-80/D.P.U. 15-81, at 310; D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55,

at 524; D.P.U. 09-30, at 377; D.P.U. 08-35, at 227; D.T.E. 03-40, at 372. Rates based on a marginal cost study allow consumers to make informed decisions regarding their use of utility services, thereby promoting efficient allocation of societal resources.
D.P.U. 15-80/D.P.U. 15-81, at 32; D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524; D.T.E. 03-40, at 372.

In support of its base distribution rate case filing, Unitil prepared a marginal cost study for its gas operations (Exh. Unitil-RJA-5 (gas)). The Company's marginal cost study includes only capacity-related distribution costs, and the Company relied on econometric methods where possible (Exh. Unitil-RJA-5, at 4 (gas)). Unitil segmented distribution capacity costs into the marginal cost of extending distribution gas mains to serve new load and the marginal cost of reinforcing the existing system to support existing and additional load (Exh. Unitil-RJA-5, at 4 (gas)). The Company used the Handy-Whitman Index[237] to remove the effects of naturally occurring price inflation (Exh. Unitil-RJA-5, at 4 (gas)).

To develop the marginal cost study, the Company estimated the marginal production expenses related to the production capacity (liquified natural gas) required to provide pressure support on the distribution system (Exh. Unitil-RJA-5, at 5 (gas)). Next, the Company addressed the capacity-related distribution O&M expenses (Exh. Unitil-RJA-5, at 5-6 (gas)). Unitil applied regression techniques and used design-day demand as an independent variable (Exh. Unitil-RJA-5, at 5-6 (gas)). The expense data was transformed using a gross domestic

[237] The Handy-Whitman Index is a data series that is based on the change in the actual cost of construction of infrastructure over time. Milford Water Company, D.P.U. 18-60, Report and Determination to the Supreme Judicial Court at 17 n.17 (2021).

product price deflator to remove the effects of price inflation from the data series (Exh. Unitil-RJA-5, at 5-6 (gas)). The Company developed general plant, administrative and general expense, and materials and supplies expense loading factors to compute estimates of marginal costs where direct quantification is either too complex or costs are insignificant (Exh. Unitil-RJA-5, at 6-8 (gas)). Unitil developed an economic carrying charge rate to convert the marginal cost of investments from a cost that represents the estimated marginal investment into the revenue requirement stream (Exh. Unitil-RJA-5, at 8 (gas)). The Company also used THE ECONOMIST'S fixed carrying charge rate method[238] to develop the distribution plant fixed carrying charge rate (Exh. Unitil-RJA-5, at 8-9 (gas)). Unitil stated that it used THE ECONOMIST'S method because the Company's old plant is nearly as useful as new plant and because this method appropriately accounts for the reduced value, due to price inflation (Exh. Unitil-RJA-5, at 9 (gas)).

2. Positions of the Parties

According to the Company, a marginal cost study is most useful for rate design where it is important to send appropriate price signals associated with additional consumption by customers (Company Brief at 292 (gas)). In addition, the Company claims that the study is forward-looking to the extent permitted by the available data (Company Brief at 292 (gas)). No other party addressed this issue on brief.

238 THE ECONOMIST'S fixed carrying charge rate method assumes that payments will escalate each year by the rate of inflation (Exh. Unitil-RJA-5, at 9 (gas)).

3. Analysis and Findings

The Department has reviewed the Company's marginal cost study and supporting exhibits (Exhs. Unitil-RJA-2, at 29-31 (gas); Unitil-RJA-5 (gas); Unitil-RJA-10 (gas)). We find that the marginal cost study developed by Unitil incorporates sufficient detail to allow a full understanding of the methods used to determine the marginal cost estimates. We find that the Company used proper econometric techniques to provide a statistically reliable estimate of the marginal plant-related costs, O&M expenses, and the marginal loading factors (Exhs. Unitil-RJA-5, at 5-8 (gas); Unitil-RJA-10, at 2-20 (gas)). The Company also used multivariate regression techniques and performed appropriate diagnostic tests to ensure the appropriateness of the regressions in its marginal cost study (Exhs. Unitil-RJA-5, at 5-8 (gas); Unitil-RJA-10, at 2-20 (gas)).

Finally, the Department has required that the estimated marginal cost needs to be meaningful, that is, the latest and most accurate that the utility can reasonably provide. D.P.U. 15-80/D.P.U. 15-81, at 313. While the Company has used data going back to 1978 in the past, Unitil's proposed marginal cost study in the instant proceeding relied on data from 1999 to 2022 (Exhs. Unitil-RJA-5, at 5 (gas); DPU 6-8 (gas)). These data include reliable capital investment data that distinguishes customer growth-related capital investment from the replacement of existing infrastructure (Exh. DPU 25-1 (gas)). Based on the use of these more recent data, we find that the Company has used reliable data to develop the marginal cost study. Accordingly, we accept the Company's updated marginal costs and marginal cost study.

J. Gas Rate Design

1. Introduction

The Company's rate structure for its gas division consists of four residential rate classes and six C&I rate classes (Exhs. Unitil-RJA-1, at 20 (gas); Unitil-RJA-6 (Rev. 4) (gas)). The residential rate classes are differentiated based on whether the customer's gas use includes gas space heating equipment and whether the customer receives a subsidized rate because of low-income (Exh. Unitil-RJA-6, at 1 (Rev. 4) (gas); proposed M.D.P.U. Nos. 264-267 (gas)). The residential group includes customers taking service under Rates R-1 and R-2 for Residential Non-Heating and Residential Non-Heating Low-Income, respectively, and customers taking service under Rates R-3 and R-4 for Residential Heating and Residential Heating Low-Income, respectively (Exhs. Unitil-RJA-1, at 20 (gas); Unitil-RJA-6, at 1 (Rev. 4) (gas); proposed M.D.P.U. Nos. 264-267 (gas)).

The C&I rate classes are based on whether the customer has a high-load or low-load factor[239] and whether the customer's gas consumption is high, medium, or low in amount (Exhs. Unitil-RJA-1, at 20 (gas); Unitil-RJA-6, at 2-3 (Rev. 4) (gas); proposed M.D.P.U. Nos. 268-270 (gas)). There are two small C&I customer groups: (1) high winter usage includes customers taking service under Rate G-41; and (2) low winter usage includes customers taking service under Rate G-51 (Exhs. Unitil-RJA-1, at 20 (gas); Unitil-RJA-6, at 2 (Rev. 4) (gas); proposed M.D.P.U. No. 268 (gas)). Similarly, there are two medium C&I

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239 High-load factor customers have winter period usage greater than or equal to 70 percent of annual use, and low-load factor customers have winter period usage less than 70 percent of annual use. The winter period is defined as the billing months of November through April (proposed M.D.P.U. Nos. 268-270 (gas)).

customer groups: (1) high winter usage includes customers taking service under Rate G-42; and (2) low winter usage includes customers taking service under Rate G-52 (Exhs. Unitil-RJA-1, at 20 (gas); Unitil-RJA-6, at 2 (Rev. 4) (gas); proposed M.D.P.U. No. 269 (gas)). Finally, there are two large C&I customer groups: (1) high winter usage includes customers taking service under Rate G-43; and (2) low winter usage includes customers taking service under Rate G-53 (Exhs. Unitil-RJA-1, at 20 (gas); Unitil-RJA-6, at 2-3 (Rev. 4) (gas); proposed M.D.P.U. No. 270 (gas)).

2. Distribution Revenue Increase and Cap

a. Company Proposal

The Company acknowledges the provisions of Section 94*I* and the Department's resulting standard that all gas and electric companies include a proposal in their future base distribution rate cases to eliminate cross-subsidies over time if the increase to any one rate class based on equalized rate of return exceeds ten percent (Exh. Unitil-RJA-1, at 41 & n.5 (gas), citing D.P.U. 20-120, at 485). The Company's initially filed ACOSS, based on its proposed revenue deficiency, resulted in a revenue percentage increase across all rate classes of approximately eleven percent (Exh. Unitil-RJA-1, at 36-37 (gas)).[240] The Company states that it cannot meet the ten-percent rate class cap required by Section 94*I* without incurring a revenue shortfall (Exh. Unitil-RJA-1, at 37 (gas)).

240 During the proceeding, the Company updated its ACOSS, which resulted in a revenue percentage increase across all rate classes of approximately 12.5 percent (Exh. DPU 19-1, Att. 1 (Excel, tab 19-1_v3_Supp. 2) (Rev. 4) (gas).

As a result, the Company proposed a revenue apportionment method where it calculated the ratio of total revenue at current rates to the revenue requirement at equalized rates of return as found in its ACOSS ("revenue-to-cost ratio") for each rate class (Exhs. Unitil-RJA-1, at 28-29, 37 (gas); Unitil RJA-4, Sch. 9 (gas)). Next, the Company adjusted the revenue-to-cost ratio for each rate class to achieve parity, i.e., each rate class received the same increase (Exhs. Unitil-RJA-1, at 28-29, 37 (gas); Unitil RJA-4, Sch. 9 (gas)). Finally, based on its judgement, the Company adjusted the revenue-to-cost ratio at parity such that no rate class had an increase greater than 125 percent of the system average base distribution rate increase and to refrain from revenue reductions (Exh. Unitil-RJA-1, at 37-40 (gas)).

Once the total revenue requirement was determined for each rate class, the Company designed its proposed rates. First, the Company established the customer charge by considering the customer costs identified in the ACOSS and demand charges, where applicable, based on the unit demand costs identified in the marginal cost study (Exh. Unitil-RJA-1, at 42 (gas)). Next, the Company deducted the revenues to be recovered under the customer and demand charges using test-year normalized billing determinants for each rate schedule (Exh. Unitil-RJA-1, at 42 (gas)). The volumetric delivery charge was then determined by dividing the revenues remaining to be collected by the test-year normalized sales under the applicable rate schedule (Exh. Unitil-RJA-1, at 42-43 (gas)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's proposed revenue increase to each rate class for its gas division does not follow rate gradualism principles (Attorney General Brief at 93, citing Exh. AG-DED-1, at 111). The Attorney General recommends limiting rate increases for each rate class to 115 percent of the overall system average increase, instead of the Company's proposed 125 percent (Attorney General Brief at 93-94, citing Exh. AG-DED-1, at 7). The Attorney General contends her recommendation provides a more balanced distribution and avoids disproportionate increases among rate classes (Attorney General Brief at 94).

ii. Company

The Company argues that it developed its gas division rate proposals based on the Department's Section 94*I* requirements and the Company's cost of service and rate of return, class contribution to present revenue levels, and customer impact considerations (Company Brief at 298 (gas), citing Exh. Unitil-RJA-1, at 36 (gas)). The Company contends that the Department has not interpreted Section 94*I* to limit a company's overall distribution rate increase to ten percent (Company Brief at 298 (gas)).

The Company asserts that because it cannot meet the ten-percent cap given the overall system increase of eleven percent, it proposed to moderately assign the increase in revenues to all rate schedules, which would consist of adjustments, in varying proportions, to the present revenue levels in all customer classes (Company Brief at 298 (gas)). According to the Company, this approach resulted in meaningful movement of the respective rate classes revenue-to-cost ratios toward equal rates of return, while requiring some level of revenue increase responsibility from all customer classes for the Company's total proposed revenue requirement (Company Brief at 300 (gas)).

c. Analysis and Findings

In adjudicated electric and gas base distribution rate cases since Section 94*I*'s enactment, the Department has evaluated the impacts of the rate class distribution revenue increases based on equalized rates of return, and the revenue adjustments for costs recovered through reconciling mechanism approved in the instant case to determine whether the impact to any rate classes exceeded ten percent of total normalized revenues and, if so, directed the companies to reallocate the revenue increase to any rate classes above ten percent to the other rate classes. See e.g., D.P.U. 22-22, at 450-451; D.P.U. 20-120, at 483-484; D.P.U. 19-120, at 432; D.P.U. 17-170, at 339-341; D.P.U. 13-75, at 338, 355. The Department, however, has not adjudicated and therefore not applied Section 94*I* in a base distribution rate case where a company proposed an overall total revenue increase above ten percent.

Although the Company's initial proposal resulted in an overall total revenue increase above ten percent for all rate classes, the Department's decisions in this Order result in an approved revenue increase for Unitil's gas division that on average is below ten percent (see Schedule 11 below). Accordingly, the Department directs Unitil in its compliance filing to apply for the gas division a ten-percent cap on the total distribution revenue increase for each rate class (inclusive of the costs recovered through reconciling mechanisms as adjusted in this Order) and to reallocate the base distribution revenues in excess of the ten-percent cap to the other rate classes to the extent they have room under the cap, as demonstrated on Schedule 11 below.[241]

[241] Costs for certain items adjusted in a base distribution rate case and recovered through reconciling mechanisms generally have remained fixed until the next base distribution rate case (e.g., local production and storage, and gas supply acquisition costs). Consistent with Department precedent, Section 94*I* applies to the revenue increase for costs

Further, to address any disparity in the rate increases among rate classes and to mitigate the increases to these rate classes, we find that it is appropriate for the Company to further allocate the revenue increase approved in this Order so that no rate class receives a rate decrease. D.P.U. 19-120, at 43; D.P.U. 17-170, at 342; D.P.U. 11-01/D.P.U. 11-02, at 478; D.T.E. 01-56, at 139.

Section 94*I* also affords the Department the discretion to determine how, and over what reasonable period of time, to phase in the elimination of rate class cross-subsidies when the class revenue allocation of the revenue increase approved in a base distribution rate case based on equalized rates of return would impact at least one rate class by ten percent or more, provided that the elimination of class cross-subsidies over time is achieved on a revenue-neutral basis. The record in this proceeding does not support a method for phasing in the elimination of rate class cross-subsidies. Additionally, the Department previously instructed all gas and electric companies to provide a proposal to eliminate cross-subsidies over time if the increase to any one rate class based on equalized rates of return exceeds ten percent. D.P.U. 20-120, at 485. In the instant case, as noted above, the Company's initially filed ACOSS, based on its proposed revenue deficiency, resulted in a revenue percentage increase across all rate classes of approximately eleven percent (Exh. Unitil-RJA-1, at 36-37 (gas)). Unitil did not submit a proposal to eliminate cross-subsidies, but simply stated that moderate progress is being made in this regard, and the Company plans to continue progress in future rate case proceedings

recovered through reconciling mechanisms that are approved in a base distribution rate case as well as the approved increase to base distribution rates. D.P.U. 20-120, at 484-485 n.234; D.P.U. 14-150, at 397-398.

(Exh. Unitil-RJA-1, at 41-42 (gas)). As noted above, the Company will reallocate the revenue increase so that no one rate class will end up with an increase of more than ten percent. Thus, a phase-in to eliminate cross-subsidies is not necessary. Nevertheless, the Company, and all utilities, are reminded that the Department expects detailed proposals in response to the Section 94*I* directive in the future. D.P.U. 20-120, at 485.

Next, we address the issue of limiting the maximum increase in base distribution rates for any rate class to 125 percent of the system average increase (Exh. Unitil-RJA-1, at 38-40). We find that this approach can prevent the disproportionate burdening of certain customer classes with excessive rate escalations (Exh. Unitil-RJA-1, at 38-40 (gas)). This approach aligns with the Department's principles of rate continuity and fairness in the rate-setting process. The reallocation of revenue requirement among rate classes using a base distribution cap of 115 percent, as recommended by the Attorney General, would increase cross-subsidization relative to the Company's proposed 125 percent cap, resulting in certain customer classes bearing a higher share of costs over their cost of service than other rate classes. We conclude that limiting the maximum increase in base distribution rates to any rate class to 125 percent of the system average is reasonable and supports a more balanced distribution of cost responsibilities among rate classes, thereby mitigating the risk of cross-subsidization, promoting rate stability, and ensuring compliance with regulatory requirements. D.P.U. 12-25, at 467. As previously noted, the Department's goals of fairness and equity include ensuring that the final rates to each rate class represent or approach the cost to serve that class. In balancing these goals with our rate structure goal of continuity, the Department finds it is not appropriate in this instance to require a zero percent floor, as shown on the illustrative Schedule 11 of this Order.

3. Customer Charges

a. Company Proposal

The Company states that to properly recover fixed costs that the utility incurs to provide service to its customers, the customer charge needs to be set at or near the embedded customer charge as determined by the ACOSS (Exh. Unitil-RJA-1, at 43 (gas)). The Company states the proposed customer charge increases are intended to: (1) align with its objective of providing fair and transparent utility rate structures; (2) promote energy conservation; and (3) minimize cross-subsidization within customer classes (Exh. Unitil-RJA-1, at 43-44 (gas)).

In developing its proposed customer charges for its gas division, Unitil increased the customer charge for all rate classes to reach approximately 25 percent of the ACOSS unit cost and move these charges closer to the respective class indicated cost of service (Exh. Unitil-RJA-1, at 45 (gas)). This method resulted in the proposed monthly customer charge for residential customers increasing from $10.00 to $15.00, and the proposed monthly customer charge for small C&I customers to increasing from $28.00 to $35.00 (Exhs. Unitil-RJA-1, at 45 (gas); Unitil-RJA-6, at 1-2 (Rev. 4) (gas); proposed M.D.P.U. Nos. 264-268 (gas)). The current customer charges for the remaining non-residential rate schedules were above 25 percent of their respective ACOSS unit cost (Exh. Unitil-RJA-1, at 45 (gas)). The Company proposed to increase these customer charges by the proposed overall system average increase (Exhs. Unitil-RJA-1, at 28, 41 (gas); Unitil-RJA-4 (Rev. 4)). This second step resulted in the proposed monthly customer charge for medium C&I customers increasing from $140.00 to $175.00, and the proposed monthly customer charge for large C&I customers increasing from $625.00 to $785.00 (Exhs. Unitil-RJA-1, at 45 (gas); Unitil-RJA-6, at 2-3 (Rev. 4) (gas); proposed M.D.P.U. Nos. 269-270 (gas)).

b. Positions of the Parties

i. Attorney General

The Attorney General urges the Department to reject the Company's proposal to increase the gas division's customer charges for residential and small C&I customers (Attorney General Brief at 95). The Attorney General contends that the Company's proposal contradicts the Department's policy goals of promoting energy efficiency, affordability, and equity objectives (Attorney General Brief at 95; Attorney General Reply Brief at 20-21). In particular, she argues that these increases would discourage energy efficiency efforts and disproportionately burden lower-income customers (Attorney General Brief at 95).

The Attorney General recommends that the Department restrict such increases to no more than the Company's initially proposed system average increase of 23.5 percent (Attorney General Brief at 95-96). Specifically, the Attorney General asserts the Department should cap the monthly customer charge for residential customers at $12.50 and cap the monthly customer charges for small C&I customers at $35.00 (Attorney General Brief at 95-96).

ii. Company

The Company contends that its proposed increase in customer charges aims to accurately reflect the necessary recovery of customer-related fixed costs (Company Brief at 301 (gas)). Further, the Company asserts that failure to recover fixed costs through fixed charges risks undermining the fundamental matching principle of rate design, leading to a misalignment between costs and revenues (Company Brief at 309-310 (gas); Company Reply Brief at 63).

Moreover, Unitil argues that shifting more fixed costs to fixed charges, as opposed to the variable charge, provides accurate economic price signals to customers and results in more conservation because it moves the marginal price signal closer to marginal costs for distribution (Company Brief at 310 (gas); Company Reply Brief at 63-64).

Finally, Unitil opposes the Attorney General's recommendation to reject or limit the increase in its customer charges (Company Reply Brief at 64). According to Unitil, proposed customer charge increases exceed the Company's initially proposed system average increase of 23.5 percent as significant portions of total fixed costs are often recovered in variable charges, particularly for residential and small commercial or general service rate classes (Company Brief at 309 (gas), citing Exh. Unitil-RJA-Rebuttal at 32-33 (gas)). The Company asserts that the inclusion of fixed costs in the variable charge sends an inaccurate economic price signal to customers, as it overstates the costs of energy consumption and understates the costs necessary to be able to provide service regardless of how much energy the customer uses (Company Brief at 309-310 (gas), citing Exh. Unitil-RJA-Rebuttal at 33 (gas); Company Reply Brief at 63-64).

c. Analysis and Findings

In setting customer charges, the Department must balance the competing rate structure goals of efficiency (i.e., setting the customer charge to recover its cost to serve) and rate continuity. D.P.U. 15-80/D.P.U. 15-81, at 328; D.P.U. 14-150, at 400; D.P.U. 10-55, at 561. The Department considers multiple factors in making its decisions regarding allowable costs, the resulting change in rates, and the resulting customer bills. D.P.U. 22-22, at 480. There is no single optimal method of setting rates that will impact all customers equally. D.P.U. 22-22, at 480. The Department recognizes that some changes can have disproportionate impacts on different customers. For a product that is priced using both a fixed charge and a variable charge, all else equal, a customer with low usage will experience a greater impact related to an increase in the fixed charge than a customer with high usage. D.P.U. 22-22, at 480. Similarly, all else equal, a customer with high usage will experience a greater impact related to an increase in the volumetric charge than a lower usage customer. D.P.U. 22-22, at 480. This is not the case in the instant proceeding; rather the Company is proposing to increase the customer charge by a larger percentage than an increase in the variable rate.

The Department acknowledges the Company's argument with respect to the importance of aligning cost recovery with cost causation and providing accurate price signals to customers (Company Brief at 309-310 (gas); Company Reply Brief at 63-64). The Department, however, is concerned that the proposed customer charges for residential customers are inconsistent with the Department's rate design goal of rate continuity. As such, we find it necessary to limit the increases in customer charges for the residential rate classes to no more than the approved overall system average base distribution increase with the GSEAF transfer removed of approximately 27.5 percent. We find that this decision to cap these customer charge increases properly balances the competing goals of the Company's need to cover its cost to serve with rate continuity for these classes of customers.

In considering the rate structure goal of efficiency to determine the customer charges, we reviewed the embedded customer charges provided by the Attorney General in her alternative ACOSS, because this ACOSS revised the Company's proposed ACOSS to account for the change to the classification of distribution mains that is approved in Section XII.H. above (Exh. AG-DED-3, Sch. 20). Regarding the proper level increase to customer charges for each residential and C&I rate class, the Department evaluates the Company's proposals on a rate-class by rate-class basis below.

K. Gas Rate-by-Rate Analysis

1. Introduction

The Department must determine on a rate-class by rate-class basis, the proper level at which to set the customer charge and distribution charges for each rate class. D.P.U. 22-22, at 473; D.P.U. 17-05-B at 260. The Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate design goal of fairness. D.P.U. 22-22, at 473; D.P.U. 17-05-B at 261. Nonetheless, the Department must balance its goals of fairness and continuity. D.P.U. 22-22, at 473-474; D.P.U. 17-05-B at 261. For this balancing, the Department has reviewed the changes in total revenue requirement by rate class and bill impacts by consumption level within rate classes. The rate design for each rate class is discussed in detail below.

2. Residential

a. Company Proposal

Rate R-1 is available for all domestic purposes in individual private dwellings and in individual apartments other than those for which Rate R-3 applies (proposed M.D.P.U. No. 264 (gas)). Rate R-3 is available for all domestic purposes in individual private dwellings and in individual apartments where such residences are heated exclusively by means of permanently installed space heating equipment (proposed M.D.P.U. No. 266 (gas)).

Income-eligible rates are also available for qualified customers (proposed M.D.P.U Nos. 265, 267). Rate R-2 is available for eligible customers for all domestic uses in individual private dwellings and in individual apartments other than those for which Rate R-4 applies (proposed M.D.P.U. No. 265 (gas)). Rate R-4 is available for eligible customers for all domestic uses in individual private dwellings and in individual apartments where such residences are heated exclusively by means of permanently installed space heating equipment (proposed M.D.P.U. No. 267 (gas)). Eligibility for Rates R-2 and R-4 is established by verification of a customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program (or its successor program) for which eligibility does not exceed 60 percent of the Massachusetts median income based on a household's gross income, or other criteria approved by the Department (proposed M.D.P.U. Nos. 265, 267 (gas)). Customers who qualify for Rates R-2 or R-4 are required each year to recertify their continuing eligibility (proposed M.D.P.U. Nos. 265, 267 (gas)). Customers on these rates receive a discount of 25 percent versus the total amount under Rate R-1 (proposed M.D.P.U. Nos. 265, 267 (gas)).

In the instant case, Unitil proposes to raise the customer charges for residential customers being served under Rates R-1, R-2, R-3, and R-4 from $10.00 to $15.00 per month (Exhs. Unitil-RJA-1, at 45 (gas); Unitil-RJA-6, at 1 (Rev. 4) (gas); proposed M.D.P.U. Nos. 264-267 (gas)). Unitil proposes to collect the remaining class revenue requirement through a flat rate distribution charge (Exh. Unitil-RJA-6, at 9 (gas)). For Rates R-1 and R-2, the Company proposes to increase its distribution charge from $1.3444 to $2.0164 per therm (Exh. Unitil-RJA-6, at 1 (Rev. 4) (gas)). For Rates R-3 and R-4, Unitil proposed an increase to its distribution charge from $1.0951 to $1.7387 per therm (Exh. Unitil-RJA-6, at 1 (Rev. 4) (gas)).

b. Analysis and Findings

According to the Attorney General's alternative ACOSS, the embedded customer charge for Rates R-1 and R-2 is $82.87 per month (Exh. AG-DED-3, Sch. 24). Based on a review of the embedded costs, the seasonal and annual bill impacts on customers, and our findings above, the Department finds that the monthly customer charge of $12.50 for Rates R-1 and R-2 is reasonable and best balances cost causation with the rate design goal of continuity. Therefore, the Department approves a monthly customer charge of $12.50 for Rates R-1 and R-2. The Department directs the Company to set the volumetric rate for rate classes R-1 and R-2 to collect the remaining R-1 and R-2 total class revenue requirement approved in this Order.

According to the Attorney General's alternative ACOSS, the embedded customer charge for Rates R-3 and R-4 is $90.18 per month (Exh. AG-DED-3, Sch. 24). Based on a review of the embedded costs and the bill impacts on customers, the seasonal and annual bill impacts on customers, and our findings above, the Department finds that a monthly customer charge of $12.50 for Rates R-3 and R-4 is reasonable and best meets our rate design goals and objectives. Therefore, the Department approves a monthly customer charge of $12.50 for Rates R-3 and R-4. The Department directs the Company to set the volumetric rate for rate classes R-3 and R-4 to collect the remaining R-3 and R-4 total class revenue requirement approved in this Order.

3. Small C&I

a. Company Proposal

Rates G-41 and G-51 are available to C&I and institutional customers with annual usage of less than 8,000 therms for all purposes when gas is for their exclusive use and not for resale (proposed M.D.P.U. No. 268 (gas)). The Company proposes to increase the current customer charge from $28.00 to $35.00 for Rates G-41 and G-51 (Exhs. Unitil-RJA-1, at 45 (gas); Unitil-RJA-6, at 2 (Rev. 4) (gas); proposed M.D.P.U. No. 268 (gas)). Unitil proposes to collect the remaining class revenue requirement through a flat volumetric charge for Rates G-41 and G-51 (Exh. Unitil-RJA-6, at 2 (Rev. 4) (gas); proposed M.D.P.U. No. 268 (gas)). For Rate G-41, Unitil proposes an increase to its distribution charge from $0.8817 to $1.3785 per therm (Exh. Unitil-RJA-6, at 2 (Rev. 4) (gas)). For Rate G-51, Unitil proposes an increase to its distribution charge from $0.7925 to $1.2015 per therm (Exh. Unitil-RJA-6, at 2 (Rev. 4) (gas)).

b. Analysis and Findings

According to the Attorney General's alternative ACOSS, the embedded customer charge for Rate G-41 is $157.57 and for Rate G-51 is $160.02 per month (Exh. AG-DED-3, Sch. 24). Based on a review of the embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $35.00 for Rates G-41 and G-51 is reasonable and best meets our rate design goals and objectives. Therefore, the Department approves a monthly customer charge of $35.00 for Rates G-41 and G-51. The Department directs the Company to set the volumetric charge for rate classes G-41 and G-51 to collect the remaining total class revenue requirements approved in this Order.

4. Medium C&I

a. Company Proposal

Rates G-42 and G-52 are available to C&I and institutional customers with annual usage of no more than 8,000 and up to 80,000 therms for all purposes when gas is for their exclusive use and not for resale (proposed M.D.P.U. No. 269 (gas)). The Company proposes to increase the current customer charge from $140.00 to $175.00 for both Rates G-42 and G-52 (Exhs. Unitil-RJA-1, at 45 (gas); Unitil-RJA-6, at 2 (Rev. 4) (gas); proposed M.D.P.U. No. 269 (gas)). The Company proposes to collect the remaining class revenue requirement through flat rate volumetric charges for Rates G-42 and G-52 (Exh. Unitil-RJA-6, at 2 (Rev. 4) (gas); proposed M.D.P.U. No. 269 (gas)). For Rate G-42, Unitil proposes an increase to its distribution charge from $0.5128 to $0.7033 per therm (Exh. Unitil-RJA-6, at 2 (Rev. 4) (gas)). For Rate G-52, Unitil proposes an increase to its distribution charge from $0.4797 to $0.6628 per therm (Exh. Unitil-RJA-6, at 2 (Rev. 4) (gas)).

b. Analysis and Findings

According to the Attorney General's alternative ACOSS, the embedded customer charge for Rate G-42 is $412.35 and for Rate G-52 is $404.98 per month (Exh. AG-DED-3, Sch. 24). Based on a review of the embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $175.00 for Rates G-42 and G-52 is reasonable and best meets our rate design goals and objectives (Exh. Unitil-RJA-7, at 7-8 (Rev. 4) (gas)). Therefore, the Department approves a monthly customer charge of $175.00 for Rates G-42 and G-52. The Department directs the Company to set the volumetric charge for rate classes G-42 and G-52 to collect the remaining total class revenue requirements approved in this Order.

5. Large C&I

a. Company Proposal

Rates G-43 and G-53 are available to C&I and institutional customers with annual usage greater than 80,000 therms for all purposes when gas is for their exclusive use and not for resale (proposed M.D.P.U. No. 270 (gas)). The Company designed rates for Rates G-43 and G-53 to include a demand charge in addition to the customer charge and volumetric charge (Exh. Unitil-RJA-6, at 2-3 (Rev. 4) (gas)). The demand charge for each rate was then increased by the overall class percentage increase (Exh. Unitil-RJA-6, at 2-3 (Rev. 4) (gas); proposed M.D.P.U. No. 270 (gas)). Finally, the volumetric charge for each rate was calculated to recover the remaining class revenue requirement (Exh. Unitil-RJA-6, at 2-3 (Rev. 4) (gas)).

Unitil proposes to increase the monthly customer charge from $625.00 to $785.00 for both Rates G-43 and G-53 (Exh. Unitil-RJA-6, at 2-3 (Rev. 4) (gas); proposed M.D.P.U. No. 270 (gas)). For Rate G-43, the Company proposes to increase the distribution charges from $0.3215 to $0.4189 per therm (Exh. Unitil-RJA-6, at 2-3 (Rev. 4) (gas)). The Company proposes to increase the demand charge for Rate G-43 from $1.85 to $2.50 per maximum daily demand therm (Exh. Unitil-RJA-6, at 2 (Rev. 4) (gas)). For Rate G-53, the Company proposes to increase the distribution charges from $0.2774 to $0.3982 per therm (Exh. Unitil-RJA-6, at 2-3 (Rev. 4) (gas)). The Company proposes to increase the demand charge for Rate G-53 from $2.30 to $2.60 per maximum daily demand therm (Exh. Unitil-RJA-6, at 2-3 (Rev. 4) (gas)).

b. Analysis and Findings

According to the Attorney General's alternative ACOSS, the embedded customer charge for Rate G-43 is $1,373.73 and for Rate G-53 is $1,344.30 per month (Exh. AG-DED-3, Sch. 24). Based on a review of the embedded costs and the seasonal and annual bill impacts on customers, the Department finds that a monthly customer charge of $785.00 for Rates G-43 and G-53 is reasonable and best meets our rate design goals and objectives (Exh. Unitil-RJA-7, at 9-10 (Rev. 4) (gas)). Therefore, the Department approves a monthly customer charge of $785.00 for Rates G-43 and G-53. The Department directs the Company to recover the remaining total class revenue requirements approved in this Order through the demand charge and the volumetric charge consistent with the rate design method proposed by the Company, which is described above.

XIII. TARIFF CHANGES

A. Capital Cost Adjustment Mechanism – Electric Division

1. Introduction

As noted in Section V.B.5. above, Unitil proposes that total plant for its electric division placed in service through December 31, 2023, be transferred for recovery through base rates (Exh. Unitil-CGDN-1, at 73 (electric)). The Company states that if the Department approves the Company's proposed PBR mechanism, including the K-bar component, the CCA mechanism will no longer be necessary after the transition to PBR has been completed, as all capital expenditures outside of the Company's 2022-2025 Grid Modernization Plan investments, as well as future investments made consistent with an approved Electric Sector Grid Modernization Plan developed consistent with the 2022 Clean Energy Act, will be recovered through the K-bar (Exh. Unitil-CGDN-1, at 71 (electric), citing Second Grid Modernization at 330-336).[242]

Accordingly, the Company proposes that on July 1, 2024, when new base distribution rates become effective, the CCA be reduced to remove the revenue requirement associated with investments that have been transferred for recovery through base distribution rates (Exh. Unitil-CGDN-1, at 73 (electric)). Further, under the Company's proposal, on January 1, 2025, a new CCA rate will be established to recover the January 2024 through June 2024 revenue requirement for the 2023 vintage investments and any reconciliation balance (Exh. Unitil-CGDN-1, at 73 (electric)). Moreover, on January 1, 2026, a new CCA will be established to recover the January 2025 through June 2025 revenue requirement related to the investments placed in service in calendar year 2024, and any reconciling balance (Exh. Unitil-CGDN-1, at 73 (electric)). After the final CCA reconciliation is completed as described above and the balance has been recovered, the Company proposes to terminate the CCA (Exh. Unitil-CGDN-1, at 73 (electric)). Finally, the Company states that it has made certain adjustments to its rate base computation to reflect the recovery of CCA investments through December 31, 2023 on the July 1, 2024 effective date of new base distribution rates (Exh. Unitil-CGDN-1, at 62 (electric)). The adjustment reflects a reduction to rate base for

242 Unitil proposed that if the Department did approve the K-bar, the Company would continue to use the CCA for non-grid modernization investments with the following modifications: (1) removal of the actual net capital expenditure cap of $11 million; and (2) increase of the annual rate cap from 1.5 percent to 2.0 percent of total revenue, per the CCA tariff (Exh. Unitil-CGDN-1, at 71-72 (electric)).

accumulated depreciation from January 1, 2024 through June 30, 2024 (Exhs. Unitil-CGDN-1, at 62 (electric); Schs. RevReq-3 (Rev. 4) (electric); RevReq-4-7 (Rev. 4) (electric)).

The Company repeated its proposals on brief (Company Brief at 170-171 (electric)). No intervenor addressed the Company's proposals on brief.

2. Analysis and Findings

In Section III.D.5.f. above, the Department approved the Company's proposal to implement a K-bar component in its PBR mechanism. In Section V.B.5 above, the Department allowed the inclusion of Unitil's electric division capital additions placed in service through 2023 into rate base and found that the project costs were prudently incurred, and the projects were used and useful in providing service to customers. The K-bar component of the PBR mechanism rate adjustments is designed to provide the Company sufficient funds to meet its service obligations while also providing the Company with incentives to be efficient in how it spends these funds. D.P.U. 18-150, at 175; D.P.U. 17-05, at 379. As such, the CCA will no longer be needed to recover costs associated with non-grid modernization capital investments. Therefore, the Department accepts the Company's proposal to transition from the CCA to PBR and to phase out the CCA mechanism.

The Company has incurred and will continue to incur costs for investments made after the end of the test year that are not included in the base distribution revenue requirement approved in this case, were not collected through the CCA, and would not be recovered through the K-bar component of the PBR mechanism. Accordingly, consistent with our finding in D.P.U. 18-150, we find it appropriate to provide Unitil with some rate relief to transition from the CCA to the K-bar component of the PBR mechanism. D.P.U. 18-150, at 176. The

Department finds it reasonable to allow Unitil to continue the CCA for the purpose of collecting: (1) the January 1, 2024 through June 30, 2024 revenue requirement on capital investments placed in service in calendar year 2023; and (2) the January 1, 2025 through June 30, 2025 revenue requirement on capital investments placed in service in calendar year 2024. Unitil shall recover these revenue requirements through the CCA factors, consistent with the Company's CCA tariff ultimately approved in this proceeding.

B. Net Metering Recovery Surcharge Tariff – Electric Division

1. Introduction

The Company proposes to modify its NMRS tariff to allow forecasted costs and revenues to be recovered in the calculation of the NMRS over the year in which the surcharge applies (Exh. Unitil-CGDN-1, at 79 (electric); proposed M.D.P.U. No. 411, § 1.08(4) (electric)). Currently, the NMRS recovers the prior year's costs and the reconciliation balance from the year before that (Exh. Unitil-CGDN-1, at 80 (electric)). According to the Company, the tariff as constructed results in a growing deferral balance that essentially requires long-term financing as the NMRS is always recovering the prior year's costs, which are then supplemented by the current year's costs (Exh. Unitil-CGDN-1, at 80-81 (electric)). Thus, the Company seeks to modify the tariff to address this growing deferral balance (Exh. Unitil-CGDN-1, at 80-81 (electric)). Alternatively, Unitil proposes to change the interest rate applicable to the deferral balance from the current customer deposit rate to the Company's approved cost of capital (Exh. Unitil-CGDN-1, at 80-81 (electric)).

The Company reiterates its proposal on brief (Company Brief at 270-272 (electric)). No other party commented on this issue on brief.

2. Analysis and Findings

The Department has reviewed the Company's NMRS tariff proposal and supporting documentation in the record (Exhs. Unitil-CGDN-1, at 80-81 (electric); proposed M.D.P.U. No. 411 (electric); DPU 25-14 (electric); DPU 25-15 & Att. (electric); DPU 25-16 (electric); DPU 34-17 (electric); DPU 34-18 (electric)). As an initial matter, we find that the calculation of the NMRS in the annual NMRS filings is consistent with the approved tariff language. While we acknowledge the Company's interest in preventing an increasing accumulation of a deferred balance, the Department, which is responsible for regulating net metering, has made significant efforts to ensure that the rules, regulations, and policies governing net metering are applied in a consistent manner across the different distribution company service territories. D.P.U. 15-155, Interlocutory Order on Scope of Proceeding at 4 (February 9, 2016) citing Order Adopting Model Net Metering Tariff, D.P.U. 09-03-A at 4, 27-28 (2009) (Department's goal is to achieve uniformity across the Commonwealth in the provision of net metering services, including the adoption of a model net metering tariff and the approval of revisions to the model interconnection tariff); see also Order Adopting a System of Assurance of Net Metering Eligibility, D.P.U. 11-11-A (2012); Rulemaking on Net Metering, D.P.U. 11-10-A (2012).[243] In keeping with this objective, we find that the Company's proposal to adjust the calculation of the NMRS or change the carrying charge component would benefit from relevant input from appropriate interested persons, to determine whether and to what extent a consistent and reasonable ratemaking adjustment may be implemented. Further, the Department notes that

243 See also G.L. c. 164, §§ 138, 139, 140; 220 CMR 18.00.

changes to the NMRS were investigated in the Department's proceeding implementing the changes to the Commonwealth's Net Metering Program prescribed by Chapter 8 of the 2021 Climate Act. Order Promulgating Final Regulations, D.P.U. 21-100-A at 78-86 (February 15, 2024). The Company did not raise these issues in that proceeding, which would have been an appropriate forum for discussion of such issues. Based on these findings, the Department finds that it is inappropriate to approve any changes to the NMRS tariff in this proceeding and, as such, denies the Company's request.

C. Basic Service Cost Adjustment – Electric Division

1. Introduction

On November 17, 2003, the Department opened an investigation to determine the level of costs incurred by Massachusetts EDCs to be included in basic service rates. Costs to be Included in Default Service, D.T.E. 03-88, Order Opening Investigation at 1-2 (2003).[244] The Company's Basic Service Cost Adjustment ("BSCA") was established pursuant to a settlement approved in that docket. D.T.E. 03-88A-F (2005). The Department required certain basic service-related

[244] On June 21, 2002, the Department (then the Department of Telecommunications and Energy) opened an investigation into all aspects of the provision of basic service (then referred to as "default service") to ensure that it is compatible with the development of an efficient competitive market and to ensure that the benefits of a competitive market are available to all Massachusetts consumers at the end of the standard offer service transition period. Procurement of Default Service, Order Opening Investigation, D.T.E. 02-40, at 1 (2002). On April 24, 2003, the Department issued an Order in that investigation that addressed, among other things, the cost components that should be included in the calculation of default service rates. D.T.E. 02-40-B at 8-21. The Department identified the types of costs that should be included in default service rates and announced that the Department would open an investigation to determine the amount of these costs incurred by each distribution company. D.T.E. 02-40-B at 15-21. The subsequent investigation occurred in docket D.T.E. 03-88.

costs then recovered in base distribution rates to be recovered through basic service rates. D.T.E. 03-88, at 4-5; D.T.E. 03-88A-F at 1. The Department determined that the amount of transferred basic costs would be fixed until a distribution company's next general distribution base rate case. D.T.E. 03-88A-F, Settlement at 2.4.

In D.P.U. 07-71, the Company's next base distribution rate case following the Department's decision in D.T.E. 03-88A-F, the Department directed the Company to remove $130,842 in basic service costs from its distribution cost of service and instead collect this expense at the same level through basic service rates. D.P.U. 07-71, at 145. The Department directed the Company to revise its basic service tariff to allow for the foregoing recovery. D.P.U. 07-71, at 145-146. The Company continues to recover $130,842 in administrative costs through its current BSCA tariff, M.D.P.U. No. 397 (electric) (see also Exh. Sch. RevReq-3-16 (Rev. 4) (electric)). The costs are for tasks associated with compliance with the Massachusetts Renewable Energy Portfolio Standard, 225 CMR 14.00; implementing the competitive bidding process; and regulatory requirement and communication with basic service customers costs pursuant to 220 CMR 11.06 (Exh. DPU 25-2, Att. (electric)). See also M.D.P.U. No. 397, Sheet 7 (electric); D.P.U. 07-71, RR-AG-13, Att.

The Company proposes four changes to the BSCA. First, the Company proposes to reduce the amount recovered through the tariff from $130,842 to $95,976 to reflect lower test-year labor hours related to the aforementioned defined tasks (Exhs. Unitil-CGDN-1, at 53 (electric); DPU 25-2, Att. (electric); AG 4-46 (electric); proposed M.D.P.U. No. 409, Sheet 7 (electric)). Second, the Company proposes to transfer the recovery of the $95,976 of test-year administrative cost recovery from the BSCA into base distribution rates (Exh. Unitil-CGDN-1, at 52 (electric)). The Company states that over 85 percent of the Company's load is served by a competitive supplier or a municipal aggregator, so recovering the cost of administering basic service from a smaller basic service customer base leads to these customers paying a disproportionate level of cost for a rate available to all customers (Exh. Unitil-CGDN-1, at 53 (electric)). Third, the Company proposes to no longer charge the administrative costs to the BSCA and instead establish a fixed recovery charge of $0.00056 per kWh to be collected as part of the BSCA (Exhs. Unitil-CGDN-1, at 53; DPU 52-12 (electric); AG 4-46 (electric); proposed M.D.P.U. No. 409, Sheet 7 (electric)). The fixed kWh charge would be calculated by dividing the administrative costs at the level to be included in base rates by the basic service kWh sales in the test year (Exhs. Unitil-CGDN-1, at 53 (electric); DPU 52-12 (electric); AG 4-46 (electric)). The Company proposes for the revenues billed on this fixed kWh charge through the BSCA to be credited to the RDAF, to prevent double recovery of the administrative costs through both the BSCA and base distribution rates (Exhs. Unitil-CGDN-1, at 52 (electric); DPU 52-12 (electric); AG 4-46 (electric); proposed M.D.P.U. No. 409, Sheet 7 (electric)). Finally, the Company proposes a change to the working capital provision in the BSCA tariff to incorporate the possibility of the Company self-supplying basic service (Exh. Unitil-CRD-1, at 3-4 (electric)). The change would allow the Company to use the number of lag days for either wholesale supply or self-supply depending on the party that is providing the basic service supply (Exhs. Unitil-CRD-1, at 3-4 (electric); DPU 8-15 (electric); DPU 52-10 (electric)).

The Company reiterated its four proposals on brief (Company Brief at 241-242; 269). No intervenor addressed these issues on brief.

2. Analysis and Findings

The Department approved the City of Fitchburg's municipal aggregation program on May 17, 2022. City of Fitchburg Municipal Aggregation, D.P.U. 20-117 (2022). The City of Fitchburg launched its municipal aggregation program in March 2023. Fitchburg Gas and Electric Light Company, D.P.U. 23-133, at 4 n.6 (January 25, 2024).[245] As a result of the move to municipal aggregation, the Company claims that over 85 percent of total load is being served by a competitive supplier or a municipal aggregator, and the cost of administering basic service is spread over a smaller customer base (Exh. Unitil-CGDN-1, at 53 (electric)).

The Department found that the impact of the City of Fitchburg's municipal load aggregation program can create an inequity for basic service customers. D.P.U. 23-133, at 7 (impacting the recovery of supply-related bad debt). The current assignment of basic service administrative costs can be considered an example of such inequity given that a majority of customers have moved off the basic service rate and the administrative costs are assigned to a much smaller number of customers remaining on the basic service rate. We find that the Company's proposed revisions to its BSCA would help address this inequity by assigning the administrative costs to a larger customer base, to which the basic service rate still is available if such customers choose to return to that offering. As such, we approve the Company's proposal to transfer the administrative costs from the BSCA to base distribution rates.

245 In that proceeding, the Company stated that the municipal aggregation program caused over 70 percent of its basic service customers to leave basic service supply. D.P.U. 23-133, at 4.

Further, we find that the Company has sufficiently demonstrated that the administrative costs have decreased from $130,842 to $95,976 (Exhs. Unitil-CGDN-1, at 53 (electric); DPU 25-2, Att. (electric); AG 4-46 (electric); proposed M.D.P.U. No. 409, Sheet 7 (electric)). We also find that the Company's proposed fixed kWh charge in the BSCA is reasonable and crediting the revenues billed on this fixed kWh charge to the RDAF to offset the amount included in base distribution rates is appropriate to prevent double recovery (Exhs. Unitil-CGDN-1, at 52-53 (electric); DPU 52-12 (electric); AG 4-46 (electric); proposed M.D.P.U. Nos. 404, Sheets 2, 4; 409, Sheet 7 (electric)). As such, we approve these proposals.

Finally, under the Company's current BSCA, the cost of working capital is determined based on purchased power from wholesale suppliers. M.D.P.U. No. 397, Sheet 7 (electric). The Department recognizes that, due to different payment terms, the Company's number of lag days varies when procuring basic service from wholesale suppliers as compared to self-supply in cases when basic service procurement is unsuccessful (Exhs. Unitil-CRD-2, at 4-5 (electric); DPU 52-10 (electric)). The Company's proposed revision would allow it to use for working capital purposes either the number of lag days for wholesale supply or self-supply depending on the party that is providing the basic service supply (Exh. DPU 8-15, at 1 (electric); proposed M.D.P.U. No. 409, Sheet 7 (electric)). We find the proposal to be reasonable, as it will allow the Company to more accurately reflect its actual working capital needs based on the nature of the basic service procurement. Further, because the cost of working capital will be based on the actual source of the Company's basic service, there is not expected to be any over- or under-recovery of working capital costs (Exh. DPU 8-15, at 2 (electric)). As such, we approve this proposal.

Based on the foregoing findings, the Department approves the Company's proposed revisions to the BSCA tariff. The Company shall provide appropriate revised BSCA and Revenue Decoupling Adjustment Clause ("RDAC") tariffs as part of the compliance filing in this proceeding. The transfer of costs and working capital changes will become effective July 1, 2024, upon approval of the compliance tariffs, but will not be reflected in a rate change until February 1, 2025, which is the next scheduled BSCA change after the rate case Order is issued (Exh. DPU 37-1, at 2 (electric)).

D. Solar Cost Adjustment Tariff – Electric Division

1. Introduction

On August 19, 2016, the Company filed with the Department a proposed program to construct, own, and operate a facility at Sawyer Passway, then a brownfield site in the City of Fitchburg, that would generate electricity from solar energy.[246] Fitchburg Gas and Electric Light Company, D.P.U. 16-148 (2016). On November 9, 2016, the Department approved a settlement ("Sawyer Passway Settlement") by and between the Company, the Attorney General, and the Low-Income Weatherization and Fuel Assistance Program Network that authorized, with certain modifications, the Company's proposed Sawyer Passway project. D.P.U. 16-148, Stamp Approval (November 9, 2016).[247] The Sawyer Passway Settlement capped the construction cost for the solar facility at $3,050,375 and allowed the Company to recover the investment and

[246] In accordance with G.L. c. 164, § 1A(f), EDCs may construct, own, and operate solar generation facilities and seek approval for cost recovery for those facilities from the Department, subject to certain limitations.

[247] Pursuant to 220 CMR 1.10(3), the Department incorporates by reference the Sawyer Passway Settlement into the record in this proceeding.

ongoing maintenance costs for the Sawyer Passway project through an SCA tariff. D.P.U. 16-148, Sawyer Passway Settlement at §§ 1.1, 1.21. Following the Sawyer Passway Settlement, the Company constructed a 1.279 megawatt solar facility at Sawyer Passway, which was placed in service in December 2017 (Exh. Unitil-KSTB-1, at 28-29 (electric)).

The Company continues to recover costs of the investments associated with the Sawyer Passway project and credits customers for revenues from this project through the SCA tariff, M.D.P.U. No. 427 (electric). More specifically, the SCA tariff provides for annual cost recovery filings that present: (1) the projected annual revenue requirement for the Sawyer Passway project for the upcoming calendar year; (2) the reconciliation of the prior year's approved annual revenue requirement projection to the actual collections received from customers during the current year; and (3) credits for the proceeds associated with energy sales, the proceeds or value associated with the Renewable Energy Certificates sold or used to comply with the Company's Renewable Portfolio Standard requirement, and the proceeds from capacity bid into the forward capacity market administered by ISO New England Inc. M.D.P.U. No. 427, §§ 3.0, 4.0 (electric). The Company makes its annual filings on or before April 2nd each year, with the SCA cost recovery factor taking effect on June 1st of that year, subject to reconciliation. M.D.P.U. No. 427, § 5.0 (electric).

In the instant proceeding, the Company proposed to transfer recovery of the costs associated with the Sawyer Passway project investments from the SCA to base distribution rates, effective July 1, 2024, and to terminate the SCA tariff (Exh. Unitil-CGDN-1, at 7-8; 19; 62; 68 (electric)). The Company's proposal is based on the administrative "time and resources" spent on annual SCA filings (Exhs. Unitil-CGDN-1, at 19 (electric); AG 4-32 (electric)). The

Company states that, while its proposal to move recovery of the investments associated with the Sawyer Passway project into base distribution rates reflects an increase in those rates, it does not result in an additional impact to customers or additional revenues to the Company because the SCA tariff no longer will recover those costs and there will be no "double recovery" (Exh. Unitil-CGDN-1, at 8, 18-19 (electric)).

Regarding market credits, the Company initially proposed to flow the revenue associated with the sale of solar energy and Renewable Energy Certificates to customers through the RDAC (Exh. Unitil-CGDN-1, at 7-8; 16, 19 (electric)). During the proceeding, the Company stated it was amenable to returning market credits to customers through the Long-Term Renewable Energy Contract Adjustment ("LTRCA") tariff, consistent with the treatment of market credits associated with other renewable energy investments (Exhs. DPU 25-4; DPU 25-5 & Att. (electric)). The Company reiterated its proposals on brief (Company Brief at 162, 175, 229-230, 291 (electric)). No intervenor addressed the Company's proposals on brief.

2. Analysis and Findings

The Department has reviewed the record supporting the Company's proposals to transfer cost recovery of the investments associated with the Sawyer Passway project from the SCA tariff to base distribution rates, return market credits to customers through the RDAC, and to terminate the SCA (Exhs. Unitil-CDNG-1, at 7-8; 19; 62; 68 (electric); Unitil-KSTB-1, at 28-29 (electric); DPU 8-18 (electric); DPU 24-5 (electric); DPU 25-5 & Atts. (electric); AG 4-31 (electric); AG 4-32) (electric)). We agree that the Company's proposal will reduce the number of reconciling mechanisms and create administrative efficiencies. We note, however, that the proposed transfer will not immediately eliminate the SCA cost recovery factor but will allow the factor to phase out in time.[248] Based on these considerations, the Department approves the Company's request to transfer recovery of the investments associated with the Sawyer Passway projects to base distribution rates, effective July 1, 2024. Unitil shall maintain the SCA tariff until such time that the Company has completed recovery or credits related to any over- or under-recoveries remaining in the mechanism as of July 1, 2024. Thereafter, the SCA tariff shall terminate.

With respect to the market revenue credits associated with the Sawyer Passway project, the Department finds that the LTRCA tariff is a more appropriate mechanism to flow the credits back to customers since it applies to all customers (similar to the RDAC), but also recovers costs associated with renewable energy contracts and service agreements. Based on the above findings, the Company shall revise and provide redline and clean versions of its SCA tariff and LTRCA tariff as part of the compliance filing in this proceeding.

E. Energy Efficiency Reconciling Factor

1. Introduction

On December 10, 2020, the Department opened an investigation to revise its Energy Efficiency Guidelines ("Guidelines") to incorporate changes in laws, Department policies, and experience gained concerning energy efficiency. Energy Efficiency Guidelines, D.P.U 20-150,

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248 The Company's most recent SCA filing was approved, subject to reconciliation, in Fitchburg Gas and Electric Light Company, D.P.U. 24-43 (May 28, 2024). The Department's decision in that proceeding will result in a new SCA rate effective July 1, 2024, comprising only any over- or under-recovery remaining in the mechanism.

Order Opening Investigation (2020).[249] In that Order, the Department presented several proposed revisions to the Guidelines ("Revised Guidelines"). D.P.U. 20-150, Order Opening Investigation at 2-3.[250] Of relevance here, the Department proposed to update Guidelines § 3.2.1.6 to revise the annual energy efficiency reconciliation factor ("EERF")[251] calculation to better align electric and gas energy efficiency cost recovery methods and to account for Department directives in Cost Based Rate Design, D.P.U. 12-126A through D.P.U. 12-126I at 23 (2013). D.P.U. 20-150, Order Opening Investigation at 3, 13-14 & Appendix A at 5-7.

The revised EERF calculation would allocate low-income energy efficiency program costs among the residential, residential low-income, and C&I sectors using a distribution revenue allocator and collect the resulting allocation from each rate class in the sector using a volumetric charge. D.P.U. 20-150, at 14, citing D.P.U. 12-126A through D.P.U. 12-126I at 23. This change would result in two EERFs, one for the combined residential and low-income sector, and one for the C&I sector. D.P.U. 20-150, Order Opening Investigation at 14. Low-income customers

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249 The Department first established energy efficiency guidelines in 2000. Methods and Practices to Evaluate and Approve Energy Efficiency Programs, D.T.E. 98-100 (2000). In 2013, the Department adopted updated energy efficiency guidelines. Updating Energy Efficiency Guidelines, D.P.U. 11-120-A (2013).

250 The Revised Guidelines were set forth in Appendix A to D.P.U. 20-150.

251 The EERF collects additional funds for approved energy efficiency programs when the cost of implementing those programs exceeds other funding sources. G.L. c. 25, § 19(a). Other funding sources are: (1) a mandatory $0.00250 per kWh system benefits charge pursuant to G.L. c. 25, § 19; (2) revenues from the forward capacity market administered by ISO New England Inc.; (3) revenues from cap-and-trade pollution control programs (e.g., the Regional Greenhouse Gas Initiative) allocated by DOER to the energy efficiency programs; and (4) other outside funding sources. G.L. c. 25, § 19(a).

would continue to receive a discount on their total electric bill. D.P.U. 20-150, Order Opening Investigation at 14.

In its final Order adopting the Revised Guidelines, the Department determined that it would be appropriate to implement the revised EERF calculation method as part of a proceeding where a full analysis of the bill impacts could be performed. D.P.U. 20-150-A at 34-35. Accordingly, the Department directed each EDC to submit a revised EERF calculation method and tariff, consistent with the Revised Guidelines, as part of its next base distribution rate case. D.P.U. 20-150-A at 35-36.[252]

In its initial filing, the Company submitted a revised Energy Efficiency Charges ("EEC") tariff, proposed M.D.P.U. No. 405 (electric), which it updated with a revised EERF calculation method designed to address the Department's directives in D.P.U. 20-150-A (see also Exhs. Unitil-CGDN-1, at 79 (electric); Unitil-CGDN-1, at 79 (electric); DPU 41-9 (electric); DPU 41-10 (electric)). Additionally, the Company proposed to modify its EEC tariff to combine the mandatory $0.00250 per kWh system benefits charge[253] pursuant to G.L. c. 25, § 19 with the EERF as a single line item on customers' bills (Exh. Unitil-CGDN-1, at 79 (electric); proposed

252 The Department approved a revised EERF calculation method for NSTAR Electric and the Cape Light Compact JPE in D.P.U. 22-22, at 468-469 & n.209. National Grid (electric) has proposed a revised EERF calculation method in its base distribution rate case currently under investigation. D.P.U. 23-150, Exhibits NG-PP-1, at 40; NG-PP-8; proposed M.D.P.U. No. 1523.

253 The Company refers to this system benefits charge as the "EEC" (proposed M.D.P.U. No. 405, §§ 1.01, 1.02 (electric)).

M.D.P.U. No. 405, § 1.01 (electric)).[254] Finally, as discussed in Section XII.D. above, the Company proposed to increase the low-income discount from 34.5 percent to 40 percent (Exhs. Unitil-RBH-1, at 40-41 (electric); Unitil-CGND-1, at 74 (electric)).

The Company maintains that the proposed changes to its EEC tariff are consistent with the Department's directives in D.P.U. 20-150-A at 36 (Company Brief at 270 (electric)). No other party addressed this issue on brief.[255]

2. Analysis and Findings

The Department has reviewed the Company's proposed EEC tariff (proposed M.D.P.U. No. 405 (electric)). The Department finds that that proposed tariff complies with the directives of D.P.U. 20-150-A at 34-36. In particular, the revised EERF calculation method appropriately allocates low-income energy efficiency program costs between a single residential and low-income combined sector and the C&I sector using a distribution revenue allocator and collects the resulting allocation from each rate class in the sector using a volumetric charge (Exh. Unitil-CGDN-1, at 79; proposed M.D.P.U. No. 405, § 1.04 (electric)). D.P.U. 20-150-A at 34; D.P.U. 20-150, Order Opening Investigation at 14, citing D.P.U. 12-126A through

254 Currently, the Company includes the EERF on customers' bills as part of the distribution charge and the EEC is a separate charge (Exh. Unitil-CGDN-1, at 79 (electric)). This proposed change will remove the EERF from the distribution charge and, instead, include it with the EEC on customers' bills as a combined charge (Exh. Unitil-CGDN-1, at 79 (electric)).

255 The Attorney General filed comments in the Company's pending 2024 EERF proceeding and stated that she does not oppose implementation of a combined residential and low-income EERF using the method contained in proposed M.D.P.U. No. 405 submitted in the instant proceeding. Fitchburg Gas and Electric Light Company, D.P.U. 24-47, Attorney General Comments at 3 (June 10, 2024).

D.P.U. 12-126I at 23. The Department affirms that this EERF calculation method is reasonable. The Department further finds that the Company's proposal to include two energy efficiency-related charges (i.e., EERF and EEC) as a combined charge on customers' bills is reasonable. Accordingly, the Department approves the Company's proposed EEC tariff, as set forth in proposed M.D.P.U. No. 405 (electric). The Company shall file an unmarked tariff with an updated tariff number as part of the compliance filing in this proceeding.

Regarding the timing of the implementation of the revised EERF calculation method, the Department's Order adopting the Revised Guidelines contemplated that each company would provide a revised EERF calculation in its next base distribution rate case. D.P.U. 20-150-A at 34-35. See also D.P.U. 22-22, at 433. A consolidated EERF already has been implemented by NSTAR Electric and Cape Light Compact JPE. NSTAR Electric Company, D.P.U. 23-41 (2023); Cape Light Compact JPE, D.P.U. 23-40 (2023). Accordingly, the Department directs the Company to calculate new EERFs, consistent with the formula presented in proposed M.D.P.U. No. 405 (electric), for effect on July 1, 2024, to be implemented as part of its 2024 EERF filing in D.P.U. 24-47.[256,257] Fitchburg Gas and Electric Light Company, D.P.U. 24-47-A (June 28, 2024).

The revisions to the EERF calculation method will result in an EERF reduction for non-low-income residential customers and an increase for low-income customers. In

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256 On May 30, 2024, the Department suspended the operation of the Company's proposed 2024 EERFs until July 1, 2024. D.P.U. 24-47, at 3.

257 Pursuant to proposed M.D.P.U. No. 405, § 1.03 (electric), the Company's 2025 EERFs will become effective June 1, 2025, unless otherwise ordered by the Department.

Section XII.D.4. above, the Department found that the Company's proposal to increase the low-income discount from 34.5 percent to 40 percent was reasonable and approved the proposal. Inasmuch as low-income customers will continue to receive a discount on their total electric bill, the increase in the discount to 40 percent will help mitigate the bill impacts from the revised EERF calculation method when implemented in D.P.U. 24-47. D.P.U. 24-47-A at 8 n.6.

F. Outdoor Lighting Delivery Service Tariffs – Electric Division

1. Company Proposal

Unitil proposes changes to its Outdoor Lighting Delivery Service tariffs for Company- and customer-owned equipment (Exhs. Unitil-JDT-1, at 21 (electric); DPU 3-8 & Atts. (electric); proposed M.D.P.U. Nos. 401, 402 (electric)). Specifically, the Company proposes to cease offering sodium vapor and metal halide luminaires for Company-owned equipment, and instead to replace them with LED fixtures, as needed (Exhs. Unitil-JDT-1, at 21 (electric); DPU 3-8, Att. 4 (electric); proposed M.D.P.U. No. 401, Sheet 1 (electric)). There will be no special charge for the replacement if done on the Company's timeline (Exhs. Unitil-JDT-1, at 21 (electric); DPU 3-8, Att. 4 (electric); proposed M.D.P.U. No. 401, Sheet 1 (electric)).[258] If, however, a customer chooses to convert to LED service before the conversion from sodium vapor and metal halide luminaires is needed, the Company proposes that the customer pay all or a portion of the costs of the conversions, including labor, material, traffic control, and overheads (Exhs. Unitil-JDT-1, at 21 (electric); DPU 3-8, Att. 4 (electric); proposed M.D.P.U. No. 401,

[258] As of September 2023, the Company did not have an estimated date as to when it anticipated replacing all Company-owned streetlight fixtures with LED fixtures (Exh. DPU 3-4 (electric)).

Sheets 1, 8 (electric)). In this instance, the Company also will determine when the conversion can be scheduled, depending on availability of Company personnel and other resources needed to complete the conversion (Exhs. Unitil-JDT-1, at 21 (electric); DPU 3-8, Att. 4 (electric); proposed M.D.P.U. No. 401, Sheet 1 (electric)). In addition, for both Company- and customer-owned equipment, and to accommodate the evolution of LED lighting fixtures, the Company plans to offer luminaire charges over a range of fixtures rather than for exact specifications for individual fixtures, as provided in the current lighting tariff (Exhs. Unitil-JDT-1, at 22 (electric); Unitil-CGDN-1, at 76 (electric); DPU 3-8, Atts. 2, 4 (electric); proposed M.D.P.U. No. 401, Sheets 3-4 (electric)).

The Company also proposes to include a provision to allow options to use advanced lighting controls for Company- and customer-owned equipment (Exhs. Unitil-CGDN-1, at 76 (electric); DPU 3-6 (electric); DPU 3-8 & Atts. 2, 4 (electric); proposed M.D.P.U. No. 401, Sheets 6-7 (electric); proposed M.D.P.U. No. 402, Sheets 4-5 (electric)). According to Unitil, this provision was recently adopted for the Company's affiliate in New Hampshire, and the Company can leverage the same billing modifications in Massachusetts (Exh. DPU 3-5 (electric)). Under this proposal, where lighting controls that meet the current ANSI C12.20 standard have been installed to allow variation from the Company's outdoor lighting hours schedule, the customer must provide verification of such installation to the Company and a schedule indicating the expected average operating wattage of each light subject to the customer's control and operation (Exhs. DPU 3-8 & Atts. 2, 4 (electric); proposed M.D.P.U. No. 401, Sheet 6 (electric); proposed M.D.P.U. No. 402, Sheet 4 (electric)). The wattage ratings must allow for the billing of kWh according to the schedule submitted by the customer to the Company and reflect any adjustments from the lighting control system including, but not limited to, fixture trimming, dimming, brightening, variable dimming, and multiple hourly schedules (Exhs. DPU 3-8 & Atts. 2, 4 (electric); proposed M.D.P.U. No. 401, Sheet 6 (electric); proposed M.D.P.U. No. 402, Sheets 4-5 (electric)).

For billing purposes relative to advanced lighting controls, the expected average operating wattage for each of the light sources resulting from installed control adjustments will be multiplied by the annual hours of operation in the tariff divided by twelve, then divided by the monthly kWh usage designated in the tariff (Exhs. DPU 3-8 & Atts. 2, 4 (electric); proposed M.D.P.U. No. 401, Sheet 6 (electric); proposed M.D.P.U. No. 402, Sheet 5 (electric)). The resulting percentage (rounded to the nearest whole number) will be applied to the monthly kWh designated in the tariff to determine the monthly kWh for billing (Exhs. DPU 3-8 & Atts. 2, 4 (electric); proposed M.D.P.U. No. 401, Sheet 6 (electric); proposed M.D.P.U. No. 402, Sheet 5 (electric)).[259] The Company states that its proposed provision for advanced lighting controls provides more options to customers through a systematic approach to billing and provides clarity to customers by including this option in the tariff (Exh. DPU 3-5 (electric)).

In designing rates for outdoor lighting service, the Company first mapped LED lights currently offered within special agreements to their equivalent range of fixtures within the new

[259] As of September 2023, the Company had one municipal customer taking service under the current outdoor lighting tariff with dimming technology applied to two different light types, totaling approximately 2800 lights (Exh. DPU 3-5 (electric)). The Company states that it is billing a reduced kWh for those lights under a tariff provision applicable to non-conforming fixtures (Exh. DPU 3-5 (electric)). The Company states that it was working with a second municipality seeking to install dimming technology as part of an overall conversion project to LED on five different light types totaling approximately 300 lights (Exh. DPU 3-5 (electric)).

tariff structure (Exh. Unitil-JDT-1, at 22 (electric)). Next, the existing special agreement rates were compared to the monthly costs of providing an LED fixture for ranges of fixtures, based on updated cost information from the ACOSS (Exh. Unitil-JDT-1, at 22 (electric)). The Company then set new rates for the proposed range of fixtures based on considerations of bill impacts for those existing special agreement customers (Exh. Unitil-JDT-1, at 22 (electric)). As a final step, once the new LED rates were set and multiplied by the count of fixtures, the Company spread the remaining revenue requirement to existing mercury vapor and high-pressure sodium fixtures (Exh. Unitil-JDT-1, at 22 (electric)).

The Company reiterated some of its outdoor lighting proposals on brief (Company Brief at 268-269; 363-364 (electric)). No other party addressed the Company's proposals on brief.

2. Analysis and Findings

The Department has reviewed the Company's proposed changes for streetlighting fixture offerings, changes in pricing, and the provision to allow for advanced lighting controls (Exhs. Unitil-JDT-1, at 21 (electric); Unitil-CGDN-1, at 76 (electric); DPU 3-5 (electric); DPU 3-6 (electric); DPU 3-8 & Atts. (electric); proposed M.D.P.U. Nos. 401, 402 (electric)). The Department finds that the Company's proposed fixture conversion, including the provisions for unplanned conversions and resulting fixture offerings for both Company-owned and customer-owned streetlights, are reasonable and meets our rate design goals and objectives. As such, we approve this aspect of the Company's outdoor lighting proposals. We also find the Company's proposed revisions to its LED streetlight pricing to offer luminaire charges over a range of fixtures rather than for exact specifications for individual fixtures are reasonable and, as such, they are approved.

Finally, the Department approves the addition of tariff provisions related to the use of advanced controls for both Company- and customer-owned equipment. As the Company noted, the proposed provisions provide more options to customers (such as fixture trimming, dimming, brightening, variable dimming, and multiple hourly schedules) through a more efficient approach to billing (Exh. DPU 3-5 (electric)). Further, the inclusion of specific tariff language regarding this option provides clarity and transparency to customers. We also expect the Company's implementation of the provisions to be relatively seamless given its experience with this provision in New Hampshire and the ability to work within the construct of its current billing system to accomplish the flexibility associated with its proposal (Exh. DPU 3-5 (electric)). The Company shall provide revised tariffs incorporating the above provisions as part of the compliance filing in this proceeding.[260]

G. Summary Rates Tariff – Electric Division

1. Introduction

During the proceeding, the Department requested that the Company propose an illustrative summary tariff for its electric division rates that conforms to the format used by NSTAR Electric in M.D.P.U. No. 1-23E and that reflects all rates proposed for effect July 1, 2024 (Exh. DPU 23-8 (Supp.) (electric)). In response, Unitil provided an illustrative tariff, but stated that the summary of rates and individual rate components are embedded into its billing process (Exh. DPU 23-8 & Att. (Supp.) (electric)). As such, the Company noted that it would take approximately three months following the issuance of the instant Order to implement and

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[260] In providing revised tariffs in the compliance filing, the Company shall take note of the revisions made during the proceeding in Exhibit DPU 3-8 & Atts.

test changes within its billing process to incorporate the actual summary tariff changes that result from the decision in this proceeding (Exh. DPU 23-8 (Supp.) (electric)).[261] No parties addressed this issue on brief.

2. Analysis and Findings

The Department finds that the format of the Company's illustrative summary tariff conforms to NSTAR Electric's format (Exh. DPU 23-8, Att. (Supp.) (electric)). Further, when compared to the Company's current summary tariff, the illustrative tariff will provide for easier review by the Department, interested stakeholders, and the public (Exh. DPU 23-8, Att. (electric)). As such, we conclude that the illustrative summary tariff format is administratively efficient and consumer friendly. Additionally, we find the resources necessary to make the required billing changes will not result in any discernable impact to customer rates. Accordingly, the Department directs the Company to file, within three months of the issuance of this Order, a summary tariff in the format presented in Exhibit DPU 23-8, Attachment (Supplemental), and reflective of the electric rates in effect at that time (i.e., rates approved in this proceeding and modified as a result of any subsequent Department decisions).

H. General Service Tariffs and Accessibility – Electric Division

1. Introduction

The Company's proposes one tariff for its electric division C&I rate classes that describes the availability, character of service, and other details pertaining to the delivery service for those customers (proposed M.D.P.U. No. 400 (electric)). There are five distinct rate classes covered

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261 The Company estimated these tasks would cost approximately $1,000 (Exh. DPU 23-8 (electric)).

by this tariff: Rate GD-1 for small C&I customers; Rate GD-2 for regular C&I customers; Rate GD-3 for large C&I customers; Rate GD-4 (closed) for optional general delivery TOU customers; and Rate GD-5 (closed) for water and/or space heating delivery rider customers (proposed M.D.P.U. No. 400 (electric)). In addition, there is an EV demand charge alternative offering, which includes four pricing schedules, available under two rate schedules, Rate GD-2 and Rate GD-3 (proposed M.D.P.U. No. 400, Sheets 3-4, 7 (electric)).

Regarding accessibility, the Company last determined its current usage requirements for each C&I rate class in 1990 (Exh. DPU 35-1 (electric), citing Fitchburg Gas and Electric Light Company, D.P.U. 90-122 (1990)). At that time, the Department examined, among other issues, usage levels and appropriate break points associated with the then-existing Rate G-1 class (Exh. DPU 35-1 (electric)). D.P.U. 90-122, at 60-61. Neither the Company nor any intervenor addressed these issues on brief.

2. Analysis and Findings

The Department finds the Company's proposed C&I tariff contains a substantial amount of information applicable to the various rate classes, spread across multiple pages. To facilitate future review by the Department, stakeholders, and customers, we direct the Company, as part of its initial filing in its next base distribution rate case, to present separate tariffs for each general service rate class.

Regarding accessibility, Unitil stated that it will review the Rate GD-1 and Rate GD-2 breakpoint and the Rate GD-2 and Rate GD-3 breakpoint as part of its next base distribution rate case to determine if changes should be made or whether the existing parameters should remain in place (Exh. DPU 51-2 (electric)). Given the length of time since its last usage requirements assessment, the Department directs the Company to examine all breakpoints, as well as the availability of demand charge alternative offerings within all of the general service rate classes. The Company shall address these issues as part of its initial filing in its next base distribution rate proceeding.

I. Revenue Decoupling Mechanism – Gas Division

1. Introduction

For its gas division, Unitil proposes to continue its per-customer RDM (Exhs. Unitil-RJA-1, at 46 (gas); Unitil-RJA-8 (gas); proposed M.D.P.U. No. 271 (gas)). Additionally, the Company seeks Department approval to recover a RDM deferral amount of $3,182,312 as of April 30, 2024 (Exh. Unitil-CGDN-1, at 60 (gas), citing Fitchburg Gas and Electric Light Company, D.P.U. 23-77, Exh. Sch. A (2023)). The deferral represents the amount by which the Company exceeded the RDM revenue cap in its most recent RDM adjustment filing. D.P.U. 23-77, Exh. Sch. A. The Company proposes to recover the deferral through the peak period RDAF over a two-year period, effective on November 1, 2024, and November 1, 2025 (Exh. Unitil-CGDN-1, at 60 (gas)).

Finally, the Company proposes to modify a provision in its current RDAC that requires mid-period adjustment filings if the actual revenues exceed a threshold of ten percent above or below its benchmark revenue level (Exh. Unitil-CGDN-1, at 59 (gas)); proposed M.D.P.U. No. 271, § 1.08 (gas)). The proposed revision would make the midpoint adjustment filings permissive, rather than required (Exh. Unitil-CGDN-1, at 59 (gas); proposed M.D.P.U. No. 271, § 1.08 (gas)).

The Company repeats its proposals on brief (Company Brief at 224-225 (gas)). No intervenor addressed these issues on brief.

2. Analysis and Findings

First, we address the Company's proposal to continue the per-customer RDM approach (Exhs. Unitil-RJA-1, at 46 (gas); Unitil-RJA-8 (gas); proposed M.D.P.U. No. 271 (gas)). In D.P.U. 20-80-B at 54, the Department directed all LDCs to transition from the per-customer RDM to a revenue cap RDM approach. The Department stated that this approach, which disincentivizes LDCs to expand their gas customer base, better aligns rate designs with climate objectives, GHG reduction targets, and other policies expressed in current climate laws. D.P.U. 20-80-B at 54. Additionally, the Department encouraged LDCs to evaluate and propose alternative rate designs and cost recovery mechanisms consistent with this direction. D.P.U. 20-80-B at 54. Given the Department's commitment to vigorously addressing the Commonwealth's climate objectives and our approval in this proceeding of the Company's proposed five-year stay out provision in its PBR mechanism, we find it necessary and appropriate for the Company to transition to a revenue cap RDM for its gas division. Therefore, the Department directs the Company in its compliance filing to modify its RDAC for its gas division from a per-customer RDM to a revenue cap RDM, effective July 1, 2024, consistent with the directives in D.P.U. 20-80-B.

Next, we address the Company's request to recover $3,182,312 in deferred RDM revenues. The Company states that by proposing to recover the deferral in the instant proceeding, the Department and parties have had a longer period (i.e., approximately ten months) to review the deferral than the 90 days afforded in the RDM reconciliation filings (Exh. DPU 6-6 (gas)). Further, the Company notes that the Department and parties have had the opportunity to review other related proposals and their associated impacts on customers (Exh. DPU 6-6 (gas)). Unitil states, however, that if the Department rejects its proposal, the Company will propose to recover the deferral as part of its next RDAC filing following the Order in the instant case (Exh. DPU 6-6 (gas)). The Department finds that the deferral request appears sufficiently discrete and straightforward that the 90-day review period applicable to the RDM filings should provide adequate time for review. Thus, we conclude that if the Company seeks to change the recovery period of its RDM deferral, it should make this request in its next peak period RDM filing.

Finally, we address Unitil's proposal to make the midpoint adjustment filings permissive rather than required (Exhs. Unitil-CGDN-1, at 59 (gas); proposed M.D.P.U. No. 271, § 1.08 (gas)). In 2017, the Department opened an investigation to develop a model RDAC tariff for LDCs' revenue decoupling mechanisms. Investigation to Develop a Model Tariff Governing Revenue Decoupling Mechanisms for Gas Distribution Companies, D.P.U. 17-93, Order Opening Investigation at 2 (April 7, 2017). During that proceeding, the Department noted that Unitil was the only relevant LDC to have a midpoint adjustment filing provision. D.P.U. 17-93-A at 6. The Department declined to require a change in the provision at that time but directed the Company to address the provision in the next base distribution rate proceeding. D.P.U. 17-93-A at 6. This issue was not resolved in the Company's next base distribution rate case, D.P.U. 19-130, which was resolved through a settlement (Exh. Unitil-CGDN-1, at 59 (gas)). Now in the instant case, the Company states that changing the midpoint adjustment filing provision to optional provides flexibility to address the potential of the ten-percent cap being triggered (Exh. DPU 6-7 (gas)). We disagree.

The Department finds that there is no compelling reason for maintaining the interim filing provision, irrespective of whether the filing required is compulsory or permissive. As an initial matter, no other LDC has such a filing provision. See D.P.U. 17-93-A at 6. Further, as the Department recognized in the model RDAC tariff investigation, the revenue cap provision of the RDM already serves to protect customers from large changes in rates. D.P.U. 17-93-A at 6. Further, the Department continues to consider the semi-annual rate adjustments under regular operation of the RDM sufficiently frequent to render the mid-period adjustments both minimal in impact and inefficient in practice. D.P.U. 17-93-A at 6. Accordingly, the Department directs the Company in its compliance filing to remove the interim filing provision from its RDAC tariff (proposed M.D.P.U. No. 271 § 1.08 (gas)).

XIV. SCHEDULES

A. Schedule 1 (Electric Division) – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	14,972,347	(211,484)	219,549	14,980,412
Depreciation & Amortization	8,080,369	(815,407)	89,273	7,354,235
Taxes Other Than Income Taxes	2,113,129	37,214	(7,848)	2,142,495
Income Taxes	1,877,218	(125,036)	(195,640)	1,556,543
Return on Rate Base	7,304,528	(478,040)	(535,013)	6,291,475
Total Cost of Service	34,347,591	(1,592,753)	(429,679)	32,325,160
OPERATING REVENUES				
Total Distribution Revenues	26,835,409	40,434	845,426	27,721,269
Other Revenues	736,656	0	0	736,656
Total Operating Revenues	27,572,065	40,434	845,426	28,457,925
Total Revenue Deficiency	**6,775,526**	**(1,633,187)**	**(1,275,105)**	**3,867,234**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

B. Schedule 2 (Electric Division) – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	69,780,706	0	0	69,780,706
Less:				
Energy Efficiency	5,240,856	0	0	5,240,856
External Transmission	11,076,649	0	0	11,076,649
Pension/PBOP Adjustment Factor	944,204	0	0	944,204
Rental Water Heaters	52,524	0	0	52,524
Default Service	27,267,872	0	0	27,267,872
Residential Assistance Adjustment Factor	1,371,992	0	0	1,371,992
Net Metering	5,827,168	0	0	5,827,168
Attorney General Consultant	160,102	0	0	160,102
SMART	3,129,218	0	0	3,129,218
Grid Mod	71,797	0	0	71,797
SRAF	0	0	0	0
ECAF	0	0	0	0
Long-Term Renewable Contract	449,961	0	0	449,961
Subtotal	55,592,343			
Test Year Internal Transmission & Distribution O&M Expense	14,188,363	0	0	14,188,363
ADJUSTMENTS TO O&M EXPENSE				
Sales for Resale O&M Expense	(501,346)	0	0	(501,346)
Non-Distribution Bad Debt	128,181	0	0	128,181
Payroll	327,553	(94,678)	(235,065)	(2,190)
Medical, Dental & Vision Insurance	247,463	41,363	0	288,826
Pension	0	(25,643)	282,589	256,946
PBOP	0	(28,507)	263,326	234,819
401(K) Costs	42,969	139	(43,108)	0
SERP	(57,457)	(10,795)	0	(68,252)
Deferred Comp Expense	2,247	7,881	(14,321)	(4,193)
Property & Liability Insurance	51,982	18,808	0	70,790
Distribution Bad Debt	201,096	(62,204)	(48,565)	90,327
Rate Case Cost Normalization	(136,302)	36,525	0	(99,777)
Reclass of EV Program Consulting Cost Removal Booked to Base	(40,571)	0	0	(40,571)
Reclass of GMP Customer Engagement Costs Booked to Base	(17,144)	0	0	(17,144)
Reclass of Section 83 A/C/D Costs	(5,774)	0	0	(5,774)
SMART Labor	222,464	0	0	222,464
Pandemic Costs	(6,272)	0	0	(6,272)
Solar way REC Removal	226,088	0	0	226,088
Self Insurance Normalization	3,080	0	0	3,080
Protected Receivables Expense	568,715	0	0	568,715
Postage Expense	12,939	3,666	0	16,605
Storm Expense And Fund Recovery Adjustment	176,000	17,000	0	193,000
VMP & SRP Expense Adjustment	43,743	0	0	43,743
Basic Service Cost Adjustment ("BSCA") Recovery Adjustment	130,842	0	0	130,842
Removal of EEI Lobbying Costs	0	(4,807)	0	(4,807)
Removal of Certain Memberships & Dues	0	(1,284)	0	(1,284)
Certain Service Company Memberships & Dues	0	0	(27,426)	(27,426)
Storm Deductible Reduction	0	(50,000)	0	(50,000)
AMI O&M Expense	0	(13,533)	0	(13,533)
Removal of Shareholder Expenses	0	(13,176)	0	(13,176)
Regulatory Assessment Update	0	55,444	0	55,444
Inflation Allowance	349,322	(90,446)	38,041	296,917
Service Company Lease Expense	0	0	4,078	4,078
Total Adjustments to O&M Expense	1,969,818	(214,247)	219,549	1,975,120
Pro-Forma O&M Expense	16,158,181	(214,247)	219,549	16,163,483
Less: Internal Transmission	1,185,834	(2,763)	0	1,183,071
Total Distribution O&M Expense	**14,972,347**	**(211,484)**	**219,549**	**14,980,412**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

C. Schedule 2A (Electric Division) – Inflation Table

Test Year Total O&M Expenses, Excluding Purchased Power	$	14,188,363
Less Normalizing Adjustments Items:		
Sales for Resale Adjustment	$	501,346
Payroll		4,975,623
Med/Dental/Vision Insurance		376,652
401K Costs		339,775
Deferred Comp		19,618
Property & Liability Insurance		221,772
Rate Case Cost Normalization		302,702
Reclass of EV Program Consulting Cost Removal Booked to Base		40,571
Reclass of GMP Customer Engagement Costs Booked to Base		17,144
Reclass of Section 83 A/C/D Costs		5,774
Pandemic Costs		6,272
Self Insurance Normalization		2,281
Postage Expense		108,053
Removal of EEI Lobbying Costs		4,676
Removal of Certain Membership & Dues		1,353
Remove VMP Labor		207,274
Remove SRP Expense		501,445
Removal of Out of Period Vegetation Management Program Adjustment		120,908
Test Year Storm Deductible		100,000
Removal of Shareholder Expenses		13,884
Regulatory Assessments		233,572
Total Normalizing Adjustment Items	$	8,100,695

Less Items not Subject to Inflation:		
Pension	$	25,643
Post-Retirement Benefits Other than Pensions		28,507
Supplemental Executive Retirement Plan		181,580
Bad Debts		951,290
Amortizations - USC Charge		68,319
Facility Leases - USC Charge		309,777
Subtotal	$	1,565,117
Residual O&M Expenses Subject to Inflation per Company	$	4,522,551
Inflation Factor		7.18%
Less: Department Adjustments		
VMP Labor Adjustment		(6,000)
Other Disallowed Dues		28,901
Storm Resiliency Program		(501,445)
Storm Resiliency Program Adjustment		(164,651)
SRP Labor Adjustment		118,463
Department Subtotal		(524,732)
Residual O&M Expense Subject to Inflation per DPU		5,047,283
Inflation Factor		7.18%
Increase in Other O&M Expense for Inflation	$	362,395
Assigned to Internal Transmission per Company		65,843
Department Adjustment to Internal Transmission Assignment		(365)
Assigned to Base Distribution	$	296,917

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

E. Schedule 3 (Electric Division) – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Depreciation Expense	8,239,445	0	0	8,239,445
Test Year Amortization Expense	1,409,992	0	0	1,409,992
Test Year Depreciation and Amortization Expense	9,649,437	0	0	9,649,437
Depreciation Adjustment	270,080	(1,004,806)	0	(734,726)
Amortization Adjustment	(798,582)	185,810	0	(612,772)
SRP Expense Adjustment	0	0	89,273	89,273
Subtotal	9,120,935	(818,996)	89,273	8,391,212
Less:				
Internal Transmission	621,196	0	0	621,196
Grid Mod	361,537	(3,589)	0	357,948
Water Heater Rentals	57,833	0	0	57,833
Total Distribution Depreciation and Amortization Expense	**8,080,369**	**(815,407)**	**89,273**	**7,354,235**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

F. Schedule 4 (Electric Division) – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	206,635,670	(511,069)	0	206,124,601
LESS:				
Internal Transmission	16,779,223	(450,422)	0	16,328,801
Plus:		0	0	0
Pro Forma Adjustments	11,330,017	(12,010,842)	0	(680,825)
Total	201,186,464	(12,071,489)	0	189,114,975
Reserve for Depreciation	96,582,584	(62,165)	0	96,520,419
LESS:				
Internal Transmission	8,659,916	(406,841)	0	8,253,075
PLUS:				
Pro Forma Adjustments	7,600,964	(6,139,492)	0	1,461,472
Total	95,523,632	(5,794,816)	0	89,728,816
Net Utility Plant in Service	105,662,832	(6,276,673)	0	99,386,159
ADDITIONS TO PLANT:				
Cash Working Capital	1,050,476	(7,441)	17,282	1,060,317
Materials and Supplies	1,561,471	703,518	0	2,264,989
Subtotal	2,611,947	696,077	17,282	3,325,306
LESS:				
Internal Transmission M&S	134,178	9,333	0	143,511
Total Additions to Plant	2,477,769	686,744	17,282	3,181,795
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax[1]	12,694,058	(67,514)	447,757	13,074,301
Excess Deferred Income Tax[1]	4,190,576	531,255	139,963	4,861,794
Customer Advances	1,548,062	0	0	1,548,062
Unclaimed Funds	7,597	0	0	7,597
Customer Deposits[1]	184,848	(16,417)	0	168,431
Subtotal	18,625,141	447,324	587,720	19,660,185
LESS:				
Internal Transmission Deferred Taxes	997,699	(21,655)	0	976,044
Internal Transmission Excess Deferred Taxes	452,315	0	0	452,315
Total Deductions from Plant	17,175,127	468,979	587,720	18,231,826
RATE BASE	90,965,474	(6,058,908)	(570,438)	84,336,128
COST OF CAPITAL	8.030%	0.0100%	-0.5800%	7.460%
RETURN ON RATE BASE	**7,304,528**	**(478,040)**	**(535,013)**	**6,291,475**

[1] The Department moved the pro forma adjustment to its proper line items Reserve for Deferred Income Taxes, Excess Deferred Income Taxes, and Customer Deposits, respectively.

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

G. Schedule 5 (Electric Division) – Cost of Capital

	PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$112,500,000	47.74%	5.33%	2.54%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$123,155,615	52.26%	10.50%	5.49%
Total Capital	$235,655,615	100.00%		8.03%
Weighted Cost of				
Debt				2.54%
Preferred				0.00%
Equity				5.49%
Cost of Capital				8.03%

	ADJUSTED PER COMPANY			
	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$112,500,000	47.74%	5.34%	2.55%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$123,155,615	52.26%	10.50%	5.49%
Total Capital	$235,655,615	100.00%		8.04%
Weighted Cost of				
Debt				2.55%
Preferred				0.00%
Equity				5.49%
Cost of Capital				8.04%

	PER ORDER			
	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$112,500,000	47.74%	5.34%	2.550%
Preferred Stock	$0	0.00%	0.00%	0.00%
Common Equity	$123,155,615	52.26%	9.40%	4.91%
Total Capital	$235,655,615	100.00%		7.46%
Weighted Cost of				
Debt				2.55%
Preferred				0.00%
Equity				4.91%
Cost of Capital				**7.46%**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

H. Schedule 6 (Electric Division) – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total Distribution Expense	14,972,347	(211,484)	219,549	14,980,412
Less: Base Uncollectibles	1,265,478	(62,204)	(48,565)	1,154,709
Subtotal	13,706,869	(149,280)	268,114	13,825,703
Taxes Other Than Income Taxes	2,113,129	37,214	(7,848)	2,142,495
Amount Subject to CWC	15,819,998	(112,066)	260,266	15,968,198
Lead/Lag Days	24.24	24.24	24.24	24.24
CWC Factor (Lead-Lag Days / 365)	6.64%	6.64%	6.64%	6.64%
Cash Working Capital Adjustment	**1,050,476**	**(7,441)**	**17,282**	**1,060,317**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

I. Schedule 7 (Electric Division) – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Property Taxes	1,518,707	0	0	1,518,707
Less:				
Internal Transmission	113,940	0	0	113,940
Grid Mod	65,728	(677)	0	65,051
Subtotal	1,339,039	677	0	1,339,716
FICA	274,545	0	0	274,545
Federal Unemployment	1,570	0	0	1,570
State Unemployment	2,944	0	0	2,944
D&O Insurance Tax	7,927	0	0	7,927
Subtotal	286,986	0	0	286,986
Less:				
Payroll Taxes Capitalized	156,666	0	0	156,666
Internal Transmission	6,649	0	0	6,649
Adjustment to Distribution Other Taxes	650,419	36,537	(7,848)	679,108
Total Taxes Other Than Income Taxes	**2,113,129**	**37,214**	**(7,848)**	**2,142,495**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

J. Schedule 8 (Electric Division) – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	90,965,474	(6,058,908)	(570,438)	84,336,128
Return on Rate Base	7,304,528	(478,040)	(535,013)	6,291,475
LESS:				
Interest Expense	2,310,523	(145,406)	(14,546)	2,150,571
Total Deductions	2,310,523	(145,406)	(14,546)	2,150,571
Net Income	4,994,005	(332,634)	(520,467)	4,140,904
Gross Up Factor	1.3759	1.3759	1.3759	1.3759
Taxable Income	6,871,223	(457,669)	(716,107)	5,697,446
Mass Income Tax (8%)	549,698	(36,614)	(57,289)	455,796
Federal Taxable Income	6,321,525	(421,055)	(658,818)	5,241,650
Federal Income Tax (21%)	1,327,520	(88,422)	(138,351)	1,100,747
Total Income Taxes	1,877,218	(125,036)	(195,640)	1,556,543

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

K. Schedule 9 (Electric Division) – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOK	83,539,506	0	0	83,539,506
Less:				
Pension/PBOP Adjust. Factor	845,426	0	(845,426)	0
External Transmission	11,091,646	0	0	11,091,646
Default Service	27,431,073	0	0	27,431,073
Energy Efficiency	4,942,625	0	0	4,942,625
Residential Assistance Adjustment Factor	1,371,992	0	0	1,371,992
Net Metering	4,825,342	0	0	4,825,342
Revenue Decoupling	0	0	0	0
Attorney General Consultant	160,102	0	0	160,102
SMART	1,401,981	0	0	1,401,981
CCAM	0	0	0	0
Grid Mod	71,797	0	0	71,797
SRAF	0	0	0	0
ECAF	1	0	0	1
Long-Term Renewable Contract	486,441	0	0	486,441
Total Adjusted Operating Revenues	30,911,080	0	845,426	31,756,506
Less: Internal Transmission	2,155,632	0	0	2,155,632
Distribution Base Revenues	28,755,448	0	845,426	29,600,874
Adjustments to Distribution Base Revenues	(1,920,039)	40,434	0	(1,879,605)
Total Distribution Base Revenues	26,835,409	40,434	845,426	27,721,269
Other Operating Revenues	5,424,020	0	0	5,424,020
Less:				
Pension/PBOP Adjust. Factor	0	0	0	0
External Transmission	0	0	0	0
Default Service	0	0	0	0
Energy Efficiency	509,759	0	0	509,759
Water Heater Rental	44,814	0	0	44,814
Residential Assistance Adjustment Factor	0	0	0	0
Net Metering	1,001,826	0	0	1,001,826
Revenue Decoupling	0	0	0	0
Attorney General Consultant	0	0	0	0
SMART	1,727,237	0	0	1,727,237
CCAM	0	0	0	0
Grid Mod	0	0	0	0
SRAF	0	0	0	0
ECAF	0	0	0	0
Long-Term Renewable Contract	0	0	0	0
Internal Transmission	1,403,728	0	0	1,403,728
Total Other Operating Revenues	736,656	0	0	736,656
Total Revenues	**27,572,065**	**40,434**	**845,426**	**28,457,925**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

L. Schedule 10 (Electric Division) – Illustrative Allocation to Rate Groups and Rate Classes

			TOTAL	RD-1	RD-2	GD-1
				Residential	Low Income	Small General
CURRENT AND PER ORDER REVENUES	Current Base Distribution Revenues	(a)	$26,193,733	$12,633,584	$3,221,372	$769,740
	Current Reconciling + Transmission Revenues	(b)	$36,595,179	$17,295,312	$3,681,718	$572,881
	Current Total Delivery Service Revenues	(c)	$62,788,911	$29,928,896	$6,903,090	$1,342,621
	Per Order Base Distribution Revenues at Equalized Rates of Return[262]	(d)	$30,906,394	$15,352,391	$3,914,627	$773,045
	Per Order Reconciling + Transmission Revenues	(e)	$34,269,303	$16,213,583	$3,403,399	$517,695
	Per Order Total Delivery Service Revenues at EROR	(f)	$65,175,697	$31,565,974	$7,318,026	$1,290,740
	Per Order Increase / (Decrease) in Total Delivery Service Revenues at EROR	(g)	$2,386,786	$1,637,078	$414,936	($51,882)
	Per Order Increase / (Decrease) in Base Distribution Revenues at EROR	(h)	$4,712,662	$2,718,807	$693,255	$3,304
	Basic Service Revenues	(i)	$56,020,091	$20,015,307	$5,149,748	$863,343
10% TOTAL DELIVERY SERVICE REVENUE CAP	10% of Current Total Delivery + Basic Service Revenues	(j)	$11,880,900	$4,994,420	$1,205,284	$220,596
	Meet 10% Cap? (includes base distribution and changes to reconciling mechanisms)	(k)		YES	YES	YES
	Increase / (Decrease) in Excess of Cap	(l)	$99,030	$0	$0	$0
	Allocator for Increase Over Cap	(m)	$30,436,175	$15,352,391	$3,914,627	$773,045
	Allocation of Cap	(n)	$99,030	$49,952	$12,737	$2,515
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(o)	$2,386,786	$1,687,030	$427,673	($49,366)
	10% Check	(p)		YES	YES	YES

262 Total Per Order Base Distribution Revenues at equalized rates of return ("EROR") vary from those in Schedule 1 due to the removal of revenues from other sources.

			TOTAL	RD-1 Residential	RD-2 Low Income	GD-1 Small General
150% BASE DISTRIBUTION REVENUE CAP	Per Order Base Distribution Revenue Increase	(q)	18.0%			
	150% of Base Distribution Revenue Increase	(r)	27.0%			
	150% Base Distribution Revenue Cap	(s)	$7,068,993	$3,409,469	$869,363	$207,732
	Meet 150% Cap?	(t)		YES	YES	YES
	Increase / (Decrease) in Excess of Cap	(u)	$173,406	$0	$0	$0
	Allocator for Increase Over Cap	(v)	$25,517,088	$15,352,391	$3,914,627	$773,045
	Allocation of Cap	(w)	$173,406	$104,330	$26,603	$5,253
	Reallocated Increase / (Decrease) in Base Distribution Revenues	(x)	$4,712,662	$2,823,137	$719,857	$8,558
	150% check	(y)		YES	YES	YES
RETEST 10% TOTAL DELIVERY SERVICE REVENUE CAP	10% of Current Total Delivery + Basic Service Revenues	(z)	$11,880,900	$4,994,420	$1,205,284	$220,596
	Meet 10% Cap?	(aa)		YES	YES	YES
	Increase / (Decrease) in Excess of Cap	(ab)	$9,519	$0	$0	$0
	Allocator for Increase Over Cap	(ac)	$25,517,088	$15,352,391	$3,914,627	$773,045
	Allocation of Cap	(ad)	$9,519	$5,727	$1,460	$288
	Reallocated Increase / (Decrease) in Base Distribution Revenues	(ae)	$4,712,662	$2,828,864	$721,317	$8,846
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(af)	$2,386,786	$1,747,135	$442,999	($46,340)
	10% Check	(ag)		YES	YES	YES
	150% Check	(ah)		YES	YES	YES
SET REVENUE FLOOR - NO REVENUE DECREASE	Above Revenue Floor?	(ai)		YES	YES	YES
	(Decrease) in Excess of Floor	(aj)	$0	$0	$0	$0
	Allocator for (Decrease) Below Floor	(ak)	$25,517,088	$15,352,391	$3,914,627	$773,045
	Allocation of Floor	(al)	$0	$0	$0	$0
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(am)	$4,712,662	$2,828,864	$721,317	$8,846

		TOTAL	RD-1	RD-2	GD-1
			Residential	**Low Income**	**Small General**
FINAL PER ORDER BASE DISTRIBUTION REVENUE	(an)	$30,906,394	$15,462,448	$3,942,690	$778,586
FINAL PER ORDER TOTAL DELIVERY SERVICE REVENUE	(ao)	$65,175,697	$31,676,031	$7,346,089	$1,296,281
Change to Other Revenue Credit	(ap)	($203,129)	uncapped	uncapped	uncapped
Allocator for Other Revenue Credit	(aq)	$25,517,088	$15,352,391	$3,914,627	$773,045
Change to Other Revenue Credit	(ar)	($203,129)	($122,213)	($31,162)	($6,154)
FINAL PER ORDER BASE DISTRIBUTION REVENUE FOR BASE DISTRIBUTION RATE DESIGN	(as)	$30,703,266	$15,340,236	$3,911,527	$772,432

Illustrative Schedule 10
Rate Classes GD-2, GD-3, GD-4

			GD-2	GD-3	GD-4
			Regular General	**Large General**	**Regular General Optional TOU**
CURRENT AND PER ORDER REVENUES	Current Base Distribution Revenues	(a)	$5,435,914	$3,818,754	$6,364
	Current Reconciling + Transmission Revenues	(b)	$8,309,281	$6,495,025	$27,971
	Current Total Delivery Service Revenues	(c)	$13,745,195	$10,313,779	$34,335
	Per Order Base Distribution Revenues at Equalized Rates of Return	(d)	$5,450,163	$4,919,087	$7,472
	Per Order Reconciling + Transmission Revenues	(e)	$7,572,750	$6,338,796	$25,492
	Per Order Total Delivery Service Revenues at EROR	(f)	$13,022,913	$11,257,883	$32,964
	Per Order Increase / (Decrease) in Total Delivery Service Revenues at EROR	(g)	($722,282)	$944,103	($1,371)
	Per Order Increase / (Decrease) in Base Distribution Revenues at EROR	(h)	$14,248	$1,100,332	$1,108
	Basic Service Revenues	(i)	$12,091,588	$17,588,344	$40,703
10% TOTAL DELIVERY SERVICE REVENUE CAP	10% of Current Total Delivery + Basic Service Revenues	(j)	$2,583,678	$2,790,212	$7,504
	Meet 10% Cap? (includes base distribution and changes to reconciling mechanisms)	(k)	YES	YES	YES
	Increase / (Decrease) in Excess of Cap	(l)	$0	$0	$0
	Allocator for Increase Over Cap	(m)	$5,450,163	$4,919,087	$7,472
	Allocation of Cap	(n)	$17,733	$16,005	$24
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(o)	($704,549)	$960,109	($1,347)
	10% Check	(p)	YES	YES	YES

			GD-2 Regular General	GD-3 Large General	GD-4 Regular General Optional TOU
150% BASE DISTRIBUTION REVENUE CAP	Per Order Base Distribution Revenue Increase	(q)	[redacted]	[redacted]	[redacted]
	150% of Base Distribution Revenue Increase	(r)	[redacted]	[redacted]	[redacted]
	150% Base Distribution Revenue Cap	(s)	$1,467,009	$1,030,580	$1,718
	Meet 150% Cap?	(t)	YES	NO	YES
	Increase / (Decrease) in Excess of Cap	(u)	$0	$69,752	$0
	Allocator for Increase Over Cap	(v)	$5,450,163	$0	$7,472
	Allocation of Cap	(w)	$37,038	$0	$51
	Reallocated Increase / (Decrease) in Base Distribution Revenues	(x)	$51,286	$1,030,580	$1,159
	150% check	(y)	YES	YES	YES
RETEST 10% TOTAL DELIVERY SERVICE REVENUE CAP	10% of Current Total Delivery + Basic Service Revenues	(z)	$2,583,678	$2,790,212	$7,504
	Meet 10% Cap?	(aa)	YES	YES	YES
	Increase / (Decrease) in Excess of Cap	(ab)	$0	$0	$0
	Allocator for Increase Over Cap	(ac)	$5,450,163	$0	$7,472
	Allocation of Cap	(ad)	$2,033	$0	$3
	Reallocated Increase / (Decrease) in Base Distribution Revenues	(ae)	$53,319	$1,030,580	$1,161
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(af)	($683,211)	$874,351	($1,318)
	10% Check	(ag)	YES	YES	YES
	150% Check	(ah)	YES	YES	YES
SET REVENUE FLOOR - NO REVENUE DECREASE	Above Revenue Floor?	(ai)	YES	YES	YES
	(Decrease) in Excess of Floor	(aj)	$0	$0	$0
	Allocator for (Decrease) Below Floor	(ak)	$5,450,163	$0	$7,472
	Allocation of Floor	(al)	$0	$0	$0
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(am)	$53,319	$1,030,580	$1,161

		GD-2	GD-3	GD-4
		Regular General	**Large General**	**Regular General Optional TOU**
FINAL PER ORDER BASE DISTRIBUTION REVENUE	(an)	$5,489,234	$4,849,335	$7,526
FINAL PER ORDER TOTAL DELIVERY SERVICE REVENUE	(ao)	$13,061,984	$11,188,131	$33,017
Change to Other Revenue Credit	(ap)	uncapped	capped	uncapped
Allocator for Other Revenue Credit	(aq)	$5,450,163	$0	$7,472
Change to Other Revenue Credit	(ar)	($43,386)	$0	($59)
FINAL PER ORDER BASE DISTRIBUTION REVENUE FOR BASE DISTRIBUTION RATE DESIGN	(as)	$5,445,848	$4,849,335	$7,466

Illustrative Schedule 10
Rate Classes GD-5, SD, SDC

			GD-5	SD	SDC
			Water and/or Space Heating Rider	**Lighting Company Owned**	**Lighting Customer Owned**
CURRENT AND PER ORDER REVENUES	Current Base Distribution Revenues	(a)	$19,340	$250,478	$38,185
	Current Reconciling + Transmission Revenues	(b)	$30,369	$117,515	$65,108
	Current Total Delivery Service Revenues	(c)	$49,710	$367,993	$103,293
	Per Order Base Distribution Revenues at Equalized Rates of Return	(d)	$19,391	$342,137	$128,082
	Per Order Reconciling + Transmission Revenues	(e)	$27,677	$110,683	$59,228
	Per Order Total Delivery Service Revenues at EROR	(f)	$47,068	$452,821	$187,310
	Per Order Increase / (Decrease) in Total Delivery Service Revenues at EROR	(g)	($2,641)	$84,828	$84,017
	Per Order Increase / (Decrease) in Base Distribution Revenues at EROR	(h)	$51	$91,660	$89,897
	Basic Service Revenues	(i)	$44,193	$144,471	$82,394
10% TOTAL DELIVERY SERVICE REVENUE CAP	10% of Current Total Delivery + Basic Service Revenues	(j)	$9,390	$51,246	$18,569
	Meet 10% Cap? (includes base distribution and changes to reconciling mechanisms)	(k)	YES	NO	NO
	Increase / (Decrease) in Excess of Cap	(l)	$0	$33,581	$65,448
	Allocator for Increase Over Cap	(m)	$19,391	$0	$0
	Allocation of Cap	(n)	$63	$0	$0
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(o)	($2,578)	$51,246	$18,569
	10% Check	(p)	YES	YES	YES

			GD-5 Water and/or Space Heating Rider	OL-SD Lighting Company Owned	OL-SDC Lighting Customer Owned
150% BASE DISTRIBUTION REVENUE CAP	Per Order Base Distribution Revenue Increase	(q)	[redacted]		
	150% of Base Distribution Revenue Increase	(r)			
	150% Base Distribution Revenue Cap	(s)	$5,219	$67,597	$10,305
	Meet 150% Cap?	(t)	YES	NO	NO
	Increase / (Decrease) in Excess of Cap	(u)	$0	$24,062	$79,592
	Allocator for Increase Over Cap	(v)	$19,391	$0	$0
	Allocation of Cap	(w)	$132	$0	$0
	Reallocated Increase / (Decrease) in Base Distribution Revenues	(x)	$182	$67,597	$10,305
	150% check	(y)	YES	YES	YES
RETEST 10% TOTAL DELIVERY SERVICE REVENUE CAP	10% of Current Total Delivery + Basic Service Revenues	(z)	$9,390	$51,246	$18,569
	Meet 10% Cap?	(aa)	YES	NO	YES
	Increase / (Decrease) in Excess of Cap	(ab)	$0	$9,519	$0
	Allocator for Increase Over Cap	(ac)	$19,391	$0	$0
	Allocation of Cap	(ad)	$7	$0	$0
	Reallocated Increase / (Decrease) in Base Distribution Revenues	(ae)	$190	$58,078	$10,305
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(af)	($2,502)	$51,246	$4,425
	10% Check	(ag)	YES	YES	YES
	150% Check	(ah)	YES	YES	YES
SET REVENUE FLOOR - NO REVENUE DECREASE	Above Revenue Floor?	(ai)	YES	YES	YES
	(Decrease) in Excess of Floor	(aj)	$0	$0	$0
	Allocator for (Decrease) Below Floor	(ak)	$19,391	$0	$0
	Allocation of Floor	(al)	$0	$0	$0
	Reallocated Increase / (Decrease) in Total Delivery Service Revenues	(am)	$190	$58,078	$10,305

		GD-5	OL-SD	OL-SDC
		Water and/or Space Heating Rider	**Lighting Company Owned**	**Lighting Customer Owned**
FINAL PER ORDER BASE DISTRIBUTION REVENUE	(an)	$19,530	$308,556	$48,490
FINAL PER ORDER TOTAL DELIVERY SERVICE REVENUE	(ao)	$47,207	$419,239	$107,717
Change to Other Revenue Credit	(ap)	uncapped	capped	capped
Allocator for Other Revenue Credit	(aq)	$19,391	$0	$0
Change to Other Revenue Credit	(ar)	($154)	$0	$0
FINAL PER ORDER BASE DISTRIBUTION REVENUE FOR BASE DISTRIBUTION RATE DESIGN	(as)	$19,376	$308,556	$48,490

Column definitions:

(a)	current rates and test year billing determinants Source: Exh. Unitil-JDT-4 - AMI Excluded, Sch 2. (Rev. 4) (electric)
(b)	using current rates and test year billing determinants
(c)	= a + b
(d)	cite to ACOS Source: Exhibit Unitil-JDT-3 Rev. 4 (5-1-24) AMI Excluded, Schedule 1, line 42 as updated to reflect approved adjustments
(e)	using illustrative rates and test year billing determinants
(f)	= d + e
(g)	= f - c
(h)	= d - a
(i)	using current rates and test year billing determinants
(j)	= 10% * (c + i)
(k)	if (g > j) , then NO, otherwise YES
(l)	if k = NO, then g - j, otherwise 0
(m)	if k = NO, then 0, otherwise d
(n)	if k = NO, then 0, otherwise [total(l) * m / total(m)]
(o)	= g - l + n
(p)	if (o < or = j) , "YES" , "NO"
(q)	= total(h)/total(a)
(r)	= q * 150%1
(s)	= total(r) * a
(t)	if h > s, then NO, otherwise YES
(u)	if t = NO, then h - s, otherwise 0
(v)	if t = NO, then 0, otherwise d
(w)	if t = NO, then 0, otherwise [total(u) * v / total(v)]
(x)	= h - u + w
(y)	if x > s, then NO, otherwise YES
(z)	= (j)

(aa)	if (x - b + e) >z, then NO, otherwise YES
(ab)	if aa = NO, then (x - b + e) - z, otherwise 0
(ac)	if aa = NO or t = NO, then 0, otherwise d
(ad)	[total(ab) * ac / total(ac)]
(ae)	= x - ab + ad
(af)	= ae + (e-b)
(ag)	if (af > z), then NO, otherwise YES
(ah)	if (ae > s), then NO, otherwise YES
(ai)	if ae < 0, then NO, otherwise YES
(aj)	if ai = NO, then ae, otherwise 0
(ak)	if ai OR aa OR t = NO, then 0, otherwise d
(al)	= [total(aj) * ak / total(ak)]
(am)	= ae - aj + al
(an)	= a + am
(ao)	= e + an
(ap)	= CONFIDENTIAL
(aq)	if (ap = uncapped), then d, otherwise 0
(ar)	= [total(ap) * aq / total(aq)]
(as)	= an + ar

M. Schedule 1 (Gas Division) – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
COST OF SERVICE				
Total O&M Expense	10,129,870	(1,118)	99,939	10,228,691
Depreciation & Amortization	10,594,761	109,994	0	10,704,755
Taxes Other Than Income Taxes	2,331,492	(136,627)	(7,230)	2,187,635
Income Taxes	2,498,756	71,896	(335,097)	2,235,554
Return on Rate Base	9,651,879	289,878	(905,747)	9,036,010
Total Cost of Service	35,206,758	334,023	(1,148,136)	34,392,645
OPERATING REVENUES				
Operating Revenues*	24,293,267	0	908,418	25,201,685
Revenue Adjustments	19,689	0	0	19,689
Total Operating Revenues	24,312,956	0	908,418	25,221,374
Total Revenue Deficiency	**10,893,802**	**334,023**	**(2,056,554)**	**9,171,272**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

N. Schedule 2 (Gas Division) – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	28,449,381	0	0	28,449,381
Less:				
Pension/PBOP Adjustment Factor	1,001,803	0	0	1,001,803
Residential assistance Adjustment Factor	884,891	0	0	884,891
Remediation Adjustment Clause	491,534	0	0	491,534
Balancing Penalty Credit Factor	(7,305)	0	0	(7,305)
CGA Excluding LPLNG, DAFP & PRO	14,922,761	0	0	14,922,761
Energy Efficiency	2,558,978	0	0	2,558,978
Rental Water Heaters & Conversion Burners	238,081	0	0	238,081
Revenue Decoupling	0	0	0	0
Attorney General Consultant	33,630	0	0	33,630
GSEP/GSERAF	0	0	0	0
Subtotal	20,124,373	0	0	20,124,373
Test Year Distribution O&M Expense	8,325,008	0	0	8,325,008
ADJUSTMENTS TO O&M EXPENSE:				
Non-Distribution Bad Debt	56,601	0	0	56,601
Payroll	324,482	(43,498)	(188,754)	92,230
Medical, Dental & Vision Insurance	220,028	26,976	0	247,004
Pension	(8,486)	0	232,219	223,733
PBOP	(6,466)	0	233,763	227,297
401K	31,556	1,629	(33,185)	0
SERP	(42,451)	(10,279)	0	(52,730)
Deferred Compensation Expense	1,660	3,915	(10,083)	(4,508)
Property Liability Insurance	46,099	14,314	0	60,413
Distribution Bad Debt	375,845	11,781	(72,534)	315,092
Rate Case Normalization	107,500	63,048	0	170,548
Self Insurance Normalization	2,326	0	0	2,326
Protected Receivable Expense	216,885	0	0	216,885
Account 887-Maintenance of Mains Normalization	50,555	0	0	50,555
Postage Expense	6,258	1,773	0	8,031
Pandemic Expense	(2,322)	0	0	(2,322)
Training Facility Rent Expense	150,000	(22,158)	1,570	129,412
Service Company Lease Expense	0	0	2,990	2,990
AMA Margin Sharing Revenue	113,172	0	0	113,172
Removal of AGA Lobbying/Membership Costs	0	(1,010)	(18,786)	(19,796)
Removal of Coalition of RNG Lobbying/Membership Co:	0	(6,615)	(3,780)	(10,395)
Removal of Certain Membership & Dues	0	(1,214)	(25,299)	(26,513)
Removal of Gas Marketing Expenses	0	(43,569)	0	(43,569)
Removal of Shareholder Expenses	0	(9,775)	0	(9,775)
Regulatory Assessment Update	0	26,055	0	26,055
Inflation Allowance	161,620	(12,491)	(18,182)	130,947
Sum of O&M Expense Adjustments	1,804,862	(1,118)	99,939	1,903,683
Distribution O&M Expense	**10,129,870**	**(1,118)**	**99,939**	**10,228,691**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

O. Schedule 2B (Gas Division) – Inflation Table

Test Year Total O&M Expenses, Excluding Purchased Power	$	8,325,007
Less Normalizing Adjustments Items:		
Payroll	$	4,278,516
Med/Dental/Vision Insurance		261,373
401K Costs		251,358
Deferred Comp		14,664
Property & Liability Insurance		186,345
Rate Case Cost Normalization		28,100
Self Insurance Normalization		758
Postage Expense		52,263
Pandemic Costs		2,322
Removal of AGA Lobbying Costs		1,010
Removal of Coalition of RNG Lobbying Costs		6,615
Removal of Certain Membership & Dues		1,214
Removal of Gas Marketing Expenses		43,569
AMA Margin Sharing Revenue		(113,172)
Removal of Shareholder Expenses		9,775
Regulatory Assessments		103,673
Total Normalizing Adjustment Items	$	5,128,384

Less Items not Subject to Inflation:		
Pension	$	8,486
Post-Retirement Benefits Other than Pensions		6,466
Supplemental Executive Retirement Plan		121,323
Bad Debts		706,146
Amortizations - USC Charge		50,089
Facility Leases - USC Charge		227,115
Subtotal	$	1,119,626
Residual O&M Expenses Subject to Inflation per Company	$	2,076,997
Inflation Factor		7.18%
Inflation Allowance per Company	$	149,128
Less: Department Adjustments		
American Gas Association Dues		18,786
Coalition for Renewable Natural Gas Dues		3,780
Other Disallowed Dues		25,299
Account 887 - Maintenance of Mains Normalization		205,365
Department Sub-total		253,230
Residual O&M Expense Subject to Inflation per DPU		1,823,767
Inflation Factor		7.18%
Inflation Allowance per DPU		130,946

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

P. Schedule 3 (Gas Division) – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year Depreciation Expense	7,557,566	0	0	7,557,566
Test Year Amortization Expense	787,005	0	0	787,005
Test Year Depreciation and Amortization Expense	8,344,571	0	0	8,344,571
Depreciation Adjustments	3,455,296	(145,984)	0	3,309,312
Amortization Adjustments	(782,379)	255,978	0	(526,401)
Subtotal	11,017,488	109,994	0	11,127,482
Less Water Heater and Conversion Burners	422,727	0	0	422,727
Total Depreciation and Amortization Expense	**10,594,761**	**109,994**	**0**	**10,704,755**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

Q. Schedule 4 (Gas Division) – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	221,080,059	(2,919,783)	0	218,160,276
LESS:				
Reserve for Depreciation and Amortizatior	74,925,701	175,224	0	75,100,925
Net Utility Plant in Service	146,154,358	(3,095,007)	0	143,059,351
ADDITIONS TO PLANT:				
Cash Working Capital	1,360,658	(17,969)	19,857	1,362,546
Materials and Supplies	1,671,626	554,249	0	2,225,875
Total Additions to Plant	3,032,284	536,280	19,857	3,588,421
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	25,825,094	(6,556,293)	453,425	19,722,226
Estimated Excess Deferred Taxes	4,997,966	577,384	126,431	5,701,781
Customer Advances	21,532	0		21,532
Customer Deposits	52,051	16,417	0	68,468
Unclaimed Funds	7,168	459	0	7,627
Total Deductions from Plant	30,903,811	(5,962,033)	579,856	25,521,634
RATE BASE	118,282,831	3,403,306	(559,999)	121,126,138
COST OF CAPITAL	8.16%	0.01%	-0.70%	7.46%
RETURN ON RATE BASE	**9,651,879**	**289,878**	**(905,747)**	**9,036,010**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to

R. Schedule 5 (Gas Division) – Cost of Capital

	PER COMPANY			
	PRINCIPAL ($000s)	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	112,500,000	47.74%	5.33%	2.54%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	123,155,615	52.26%	10.75%	5.62%
Total Capital	235,655,615	100.00%		8.16%
Weighted Cost of				
Debt				2.54%
Preferred				0.00%
Equity				5.62%
Cost of Capital				8.16%

	COMPANY ADJUSTMENTS			
	PRINCIPAL ($000s)	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	112,500,000	47.74%	5.34%	2.55%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	123,155,615	52.26%	10.75%	5.62%
Total Capital	235,655,615	100.00%		8.17%
Weighted Cost of				
Debt				2.55%
Preferred				0.00%
Equity				5.62%
Cost of Capital				8.17%

	PER ORDER			
	PRINCIPAL ($000s)	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	112,500,000	47.74%	5.34%	2.55%
Preferred Stock	0	0.00%	0.00%	0.00%
Common Equity	123,155,615	52.26%	9.40%	4.91%
Total Capital	235,655,615	100.00%		7.46%
Weighted Cost of				
Debt				2.55%
Preferred				0.00%
Equity				4.91%
Cost of Capital				7.46%

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

S. Schedule 6 (Gas Division) – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Total Distribution O&M Expense	10,129,870	(1,118)	99,939	10,228,691
Less: Uncollectible Accounts	1,138,592	11,781	(72,534)	1,077,839
Subtotal	8,991,278	(12,899)	172,473	9,150,852
Plus: Taxes Other than Income Taxes	2,331,492	(136,627)	(7,230)	2,187,635
Amount Subject to Cash Working Capital	11,322,770	(149,526)	165,243	11,338,487
Lead/lag Days	43.86	43.86	43.86	43.86
Cash Working Capital Factor	12.02%	12.02%	12.02%	12.02%
Cash Working Capital Allowance	**1,360,658**	**(17,969)**	**19,857**	**1,362,546**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

T. Schedule 7 (Gas Division) – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Property Taxes per Books	1,524,794	0	0	1,524,794
Payroll Taxes:				
FICA	260,630	0	0	260,630
Federal Unemployment	1,491	0	0	1,491
Mass Unemployment	2,795	0	0	2,795
Mass State Health	0	0	0	0
D&O Insurance Tax	7,815	0	0	7,815
Less: Payroll Taxes Capitalized	149,400	0	0	149,400
	123,331	0	0	123,331
Property and Payroll Taxes	1,648,125	0	0	1,648,125
Adjustment to Distribution Other Taxes	683,367	(136,627)	(7,230)	539,510
Taxes Other Than Income	**2,331,492**	**(136,627)**	**(7,230)**	**2,187,635**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

U. Schedule 8 (Gas Division) – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	118,282,831	3,403,306	(559,999)	121,126,138
Return on Rate Base	9,651,879	289,878	(905,747)	9,036,010
LESS:				
Interest Expense	3,004,384	98,613	(14,280)	3,088,717
Net Income	6,647,495	191,266	(891,468)	5,947,293
Gross Up Factor	1.3759	1.3759	1.3759	1.3759
Taxable Income	9,146,251	263,162	(1,226,565)	8,182,847
Massachusetts Income Tax (8%)	731,700	21,053	(98,125)	654,628
Federal Taxable Income	8,414,551	242,109	(1,128,440)	7,528,219
Federal Income Tax Calculated (21%)	1,767,056	50,843	(236,972)	1,580,926
Total Income Taxes	**2,498,756**	**71,896**	**(335,097)**	**2,235,554**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

V. Schedule 9 (Gas Division) – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
OPERATING REVENUES PER BOOKS	47,356,594	0	0	47,356,594
Less:				
Pension/PBOP Adjustment Factor	908,418	0	(908,418)	0
Residential Assistance Adjustment Factor	884,891	0	0	884,891
Remediation Adjustment Clause	476,595	0	0	476,595
Balancing Penalty Credit Factor	(7,305)	0	0	(7,305)
CGA Excluding LPLNG, DAFP & PRO	15,099,523	0	0	15,099,523
Energy Efficiency	2,653,571	0	0	2,653,571
Revenue Decoupling	0	0	0	0
Attorney General Consultant	33,630	0	0	33,630
GSEP/GSERAF	0	0	0	0
Subtotal	20,049,323	0	(908,418)	19,140,905
Adjusted Operating Revenues	27,307,271	0	908,418	28,215,689
Adjustments to Distribution Base Revenues	(3,014,004)	0	0	(3,014,004)
Total Operating Revenues	24,293,267	0	908,418	25,201,685
Other Operating Revenues	467,384	0	0	467,384
Less: Water Heater and Burner Rental	447,695	0	0	447,695
Distribution Other Operating Revenues	19,689	0	0	19,689
Total Revenues	24,312,956	0	908,418	25,221,374

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

W. Schedule 10 (Gas Division) – Illustrative Calculation of Revenue Increase by Service

	PER ORDER		
	TOTAL COMPANY per Order	DISTRIBUTION SERVICE	GAS SERVICE
Test-Year Cost of Gas	$ 22,989,947	$ -	$ 22,989,947
O&M Expense	10,301,225	9,718,211	583,014
Operation Expenses	33,291,172	9,718,211	23,572,962
Depreciation Expense	10,444,151	10,341,372	102,779
Amortization Expense	260,604	234,589	26,016
Taxes Other than Income Taxes	2,188,795	2,126,056	62,739
Income Taxes	2,235,712	2,186,803	48,909
Rate Base	$ 121,134,678	$ 118,484,699	$ 2,649,979
Rate of Return	7.46%	7.46%	7.46%
Return on Rate Base	$ 9,036,647	$ 8,838,959	$ 197,688
Cost of Service	$ 34,467,134	$ 33,445,989	$ 1,021,145
Revenues Credited to Cost of Service	(753,980)	(753,980)	$ -
Total Cost of Service	**$ 33,713,154**	**$ 32,692,009**	**$ 1,021,145**
Operating Revenues	23,558,976	22,454,403	1,104,573
GSEP Revenues Transferred to Cost of Service	4,048,138	4,048,138	$ -
PAF Revenues Transferred to Cost of Service	1,047,451	1,047,451	$ -
Revenue Adjustments	$ -	$ -	$ -
Total Operating Revenues	**$ 28,654,565**	**$ 27,549,992**	**$ 1,104,573**
Revenue Deficiency	**$ 5,812,569**	**$ 5,895,996**	**$ (83,428)**

FOR ILLUSTRATIVE PURPOSES ONLY

X. Schedule 11 (Gas Division) – Illustrative Allocation to Rate Groups and Rate Classes

					R-1	R-2	R-3	R-4	G-41	G-51	G-42	G-52	G-43	G-53
				TOTAL	Residential Non-Heating Customer	Low-Income Non-Heating Customer	Residential Heating Customer	Residential Low-Income Heating Customer	General Service - Small, High Winter Use	General Service - Small, Low Winter Use	General Service - Medium, High Winter Use	General Service - Medium, Low Winter Use	General Service - Large, High Winter Use	General Service - Large, Low Winter Use
CURRENT AND PROPOSED REVENUES	Current Base Distribution Revenues	**A**	*Using current rates and test year billing determinants Source: Exhibit Unitil-6 Rev. Proof (Rev.4), Schedule 2*	22,454,403	740,990	247,061	9,660,866	3,066,606	2,431,139	484,843	2,497,575	588,709	1,562,107	1,174,507
	Current LDAC Revenue	**B**	*Using current rates and test year billing determinants*	12,648,284	296,740	102,969	5,805,951	1,847,712	1,186,844	253,262	1,359,153	310,418	835,463	649,772
	Current Total Delivery Service Revenue	**C**	**= A + B**	35,102,687	1,037,730	350,030	15,466,817	4,914,318	3,617,983	738,105	3,856,728	899,127	2,397,570	1,824,279
	Per Order Base Distribution Revenues at Equalized Rates of Return	**D**	*Cite to ACOS and as shown in Schedule 10*	32,692,009	2,067,589	692,346	15,005,641	4,765,023	4,018,942	759,528	3,028,630	648,436	1,028,402	677,471
	Per Order LDAC Revenues	**E**	*Excludes GSEP costs to be rolled into base rates Base Rates*	6,999,341	200,831	69,688	3,923,618	1,248,670	396,843	87,100	398,435	95,243	317,492	261,421
	Per Order Total Delivery Service Revenues at EROR	**F**	**= D + E**	39,691,350	2,268,420	762,034	18,929,259	6,013,693	4,415,785	846,628	3,427,065	743,679	1,345,894	938,892
	Increase / (Decrease) in Total Delivery Service Revenues at EROR	**G**	**= F - C**	4,588,663	1,230,690	412,004	3,462,442	1,099,375	797,802	108,523	(429,663)	(155,448)	(1,051,677)	(885,387)
	Per Order Increase / (Decrease) in Base Distribution Revenues at EROR	**H**	**= D - A**	10,237,606	1,326,600	445,285	5,344,775	1,698,417	1,587,803	274,685	531,056	59,727	(533,705)	(497,036)
	Current CGAC Revenues	**I**	*Using current rates and test year billing determinants*	22,989,947	358,441	124,378	7,251,337	2,307,698	2,139,433	455,886	3,966,951	914,781	3,067,405	2,403,637
	Per Order CGAC Revenues	**J**	*Cite to ACOS and as shown in Schedule 10*	22,906,519	362,951	125,944	7,198,136	2,290,767	2,123,676	461,613	3,938,016	926,251	3,045,315	2,433,850
	Per Order Total Increase	**K**	**= G + (J - I)**	4,505,235	1,235,201	413,570	3,409,241	1,079,568	779,379	113,669	(463,543)	(145,140)	(1,077,590)	(858,231)

10% TOTAL DELIVERY SERVICE REVENUE CAP	ITERATION 1	10% of Current Total Delivery + Per Order Current CGAC Revenues	**L**	= 10% * **(C + I)**	**5,809,263**	139,617	47,441	2,271,815	722,202	575,742	119,399	782,368	181,391	546,498	422,792
		Meet 10% Cap?	**M**	if **K > L**, then NO, otherwise YES		**No**	**No**	**No**	**No**	**No**	**YES**	**YES**	**YES**	**YES**	**YES**
		Increase / (Decrease) in Excess of Cap	**N**	if **M** = NO, then **K - L**, otherwise 0	3,160,141	1,095,583	366,129	1,137,426	357,366	203,637	-	-	-	-	-
		Allocator for Increase Over Cap	**O**	if **M** = NO, then 0, otherwise **D**	6,142,468	-	-	-	-	-	759,528	3,028,630	648,436	1,028,402	677,471
		Allocation of Cap	**P**	if **M** = NO, then 0, otherwise [total **N** * **O** / total **O**]	3,160,141	-	-	-	-	-	390,758	1,558,152	333,604	529,086	348,541
		Reallocated Per Order Increase / (Decrease) in Total Revenues	**Q**	= **K - N + P**	4,486,123	139,617	47,441	2,271,815	722,202	575,742	504,427	1,094,609	188,464	(548,504)	(509,689)
		10% Check	**R**	if **Q > L**, then NO, otherwise YES		**YES**	**YES**	**YES**	**YES**	**YES**	**No**	**No**	**No**	**YES**	**YES**
	ITERATION 2	Increase / (Decrease) in Excess of Cap	**S**	if R = NO, then Q - L, otherwiese 0	704,342	-	-	-	-	-	385,028	312,241	7,073	-	-
		Allocator for Increase Over Cap	**T**	if **M OR R** = NO, then 0, otherwise **D**	1,705,873	-	-	-	-	-	-	-	-	1,028,402	677,471
		Allocation of Cap	**U**	if T = 0, then 0, otherwise [total S * T / total T	704,342	-	-	-	-	-	-	-	-	424,619	279,723
		Reallocated Per Order Total Increase / (Decrease) in Total Revenues	**V**	Q - S + U	4,486,123	139,617	47,441	2,271,815	722,202	575,742	119,399	782,368	181,391	(123,884)	(229,967)
		Meet 10% Cap Check	**W**	if V **> L**, then NO, otherwise YES		**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**
		Distribution Revenue Increases	**X**	H - N - P + S + U	10,237,606	231,016	79,156	4,207,349	1,341,051	1,384,166	280,415	1,776,967	386,258	420,000	131,228

125%[1] BASE DISTRIBUTION REVENUE CAP	ITERATION 1	Per Order Base Distribution Revenue Increase	Y	= total **H** / total **A**	**45.59%**										
		125%[1] of Base Distribution Revenue Cap	Z	= Total **Y** * 1.25 * **A**)	12,797,007	422,298	140,803	5,505,832	1,747,692	1,385,532	276,317	1,423,395	335,512	890,262	669,364
		Meet 125%[1] Cap?	AA	if **X > Z**, then NO, otherwise YES		YES	YES	YES	YES	YES	No	No	No	YES	YES
		Increase / (Decrease) in Excess of Cap	AB	if **AA** = NO, then **X - Z**, otherwise 0	408,416	-	-	-	-	-	4,097	353,572	50,747	-	-
		Allocator for Increase Over Cap	AC	if **AA or R or M** = NO, then 0, otherwise **D**	1,705,873	-	-	-	-	-	-	-	-	1,028,402	677,471
		Allocation of Cap[2]	AD	if **AC** = 0, then 0, otherwise [total **AB * AC / total AC**]	408,416	-	-	-	-	-	-	-	-	246,217	162,198
		Reallocated Per Order Increase / (Decrease) in Base Distribution Revenues	AE	**= X - AB + AD**	10,237,606	231,016	79,156	4,207,349	1,341,051	1,384,166	276,317	1,423,395	335,512	666,217	293,427
		125%[1] check	AF	if **AE > Z**, then NO, otherwise YES		YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Base Distribution		Above Revenue Floor of 0	AG	If **AE < 0**, then **AE**, else 0		YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
		Per Order Base Distribution Revenues	AH	**= AE + A**	32,692,009	972,006	326,217	13,868,215	4,407,657	3,815,305	761,161	3,920,970	924,221	2,228,325	1,467,933
		Per Order Total Revenues	AJ	**= AH + J + E**	62,597,869	1,535,788	521,849	24,989,969	7,947,094	6,335,824	1,309,874	8,257,421	1,945,715	5,591,132	4,163,204
		Per Order Increase to Total Revenues	AK	**= AJ - (C + I)**	4,505,235	139,617	47,441	2,271,815	725,078	578,408	115,882	433,742	131,807	126,157	(64,712)
		Percent increase to Distribution Revenues Per Order	AL	**= AE / A**	45.59%	31.18%	32.04%	43.55%	43.73%	56.93%	56.99%	56.99%	56.99%	42.65%	24.98%
		Percent increase to total Revenues Per Order	AM	**= AK / (C + I)**	7.76%	10.00%	10.00%	10.00%	10.04%	10.05%	9.71%	5.54%	7.27%	2.31%	-1.53%

FOR ILLUSTRATIVE PURPOSES ONLY

XV. ORDER

Accordingly, after due notice, hearing, opportunity to comment, and consideration, it is

ORDERED: That the tariffs M.D.P.U. Nos. 398 through 412 filed by Fitchburg Gas and Electric Light Company for its electric division on August 17, 2023, to become effective September 1, 2023, are DISALLOWED; and it is

FURTHER ORDERED: That the tariffs M.D.P.U. Nos. 264 through 274 filed by Fitchburg Gas and Electric Light Company for its gas division on August 17, 2023, to become effective September 1, 2023, are DISALLOWED; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company shall file new schedules of rates and charges designed to increase annual electric revenues by $3,867,234; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company shall file new schedules of rates and charges designed to increase annual gas revenues by $9,171,272; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company shall file all rates and charges required by this Order and shall design all rates in compliance with this Order; and it is

FURTHER ORDERED: That Fitchburg Gas and Electric Light Company shall comply with all other directives contained in this Order; and it is

FURTHER ORDERED: That the new rates shall apply to electricity and gas consumed on or after July 1, 2024, but unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

____
James M. Van Nostrand, Chair

____
Cecile M. Fraser, Commissioner

____
Staci Rubin, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.