The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 22-22 November 30, 2022

Petition of NSTAR Electric Company, doing business as Eversource Energy, 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.

APPEARANCES: Cheryl M. Kimball, Esq.
Danielle C. Winter, Esq.
Jessica Buno Ralston, Esq.
Kerri A. Mahoney, Esq.
99 High Street, Ste 2900
Boston, Massachusetts 02110
FOR: NSTAR ELECTRIC COMPANY
Petitioner

Maura Healey, Attorney General
Commonwealth of Massachusetts
By: Joseph W. Rogers
Matthew E. Saunders
Elizabeth Anderson
Shannon S. Beale
Jacquelyn K. Bihrle
Jo Ann Bodemer
Donald W. Boecke
Jonathan F. Dinerstein
Jessica R. Freedman
Ashley Gagnon
Chris Modlish
Assistant Attorneys General
Kelly Caiazzo
Special Assistant Attorney General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Department of Energy Resources
Commonwealth of Massachusetts
Robert H. Hoaglund II, General Counsel
Rachel Graham Evans, Deputy General Counsel
Ben Dobbs, Deputy General Counsel
100 Cambridge Street, Suite 1020
Boston, Massachusetts 02114
Intervenor

Jerrold Oppenheim, Esq.
57 Middle Street
Gloucester, Massachusetts 01930
FOR: THE LOW-INCOME WEATHERIZATION AND FUEL ASSISTANCE PROGRAM NETWORK
Intervenor

Amy E. Boyd, Esq.
Kyle T. Murray, Esq.
198 Tremont Street, Suite 415
Boston, Massachusetts 02111
FOR: ACADIA CENTER
Intervenor

Audrey Eidelman Kiernan, Esq.
Rebecca F. Zachas, Esq.
BCK LAW, P.C.
1337 Massachusetts Avenue, Box 314
Arlington, Massachusetts 02476
FOR: CAPE LIGHT COMPACT JPE
Intervenor

Priya Gandbhir, Esq.
Conservation Law Foundation
62 Summer Street
Boston, Massachusetts 02110
FOR: CONSERVATION LAW FOUNDATION
Intervenor

Brooke Skulley, Esq.
Stacey M. Donnelly, Esq.
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
FOR: MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY
Intervenor

Jeremy McDiarmid, Esq.
Northeast Clean Energy Council, Inc.
444 Somerville Avenue
Somerville, Massachusetts 02143
FOR: NORTHEAST CLEAN ENERGY COUNCIL, INC.
Intervenor

Robert Ruddock, Esq.
Ruddock Office
436 Pleasant Street
Belmont, Massachusetts 02478
FOR: THE ENERGY CONSORTIUM
Intervenor

Kevin Conroy, Esq.
Zachary Gerson, Esq.
Cloe Pippin, Esq.
Foley Hoag LLP
155 Seaport Boulevard
Boston, Massachusetts 02210-2600
FOR: UNIVERSITY OF MASSACHUSETTS
Intervenor

Jay Myers, Esq.
Locke Lord LLP
111 Huntington Avenue
Boston, Massachusetts 02199
FOR: POWEROPTIONS, INC.
Limited Intervenor

Charles S. McLaughlin, Jr.
Senior Town Attorney
Town of Barnstable
367 Main Street
Hyannis, Massachusetts 02601
FOR: TOWN OF BARNSTABLE
Limited Intervenor

Walter A. Foskett, Esq.
Robert D. Shapiro, Esq.
Duncan & Allen
35 Braintree Hill Office Park, Suite 201
Braintree, Massachusetts 02184
FOR: NRG HOME f/k/a RELIANT ENERGY NORTHEAST LLC, DIRECT ENERGY SERVICES, LLC, DIRECT ENERGY BUSINESS, LLC, DIRECT ENERGY BUSINESS MARKETING, LLC, GREEN MOUNTAIN ENERGY COMPANY, ENERGY PLUS HOLDINGS LLC, and XOOM ENERGY MASSACHUSETTS, LLC
Joint Limited Participants

Melissa M. Horne, Esq.
HIGGINS, CAVANAGH & COONEY, LLP
10 Dorrance Street, Suite 400
Providence, Rhode Island 02903
FOR: WALMART, INC.
Limited Participant

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I. INTRODUCTION

On January 14, 2022, NSTAR Electric Company d/b/a Eversource Energy ("NSTAR Electric" or "Company") filed a petition with the Department of Public Utilities ("Department") for an increase in its electric base distribution rates to generate $89,477,862 in additional revenues. The Company also proposed to transfer costs recovered through certain reconciling mechanisms, which totaled $58,184,827 in calendar year 2020, to base distribution rates.[1] Based on this proposal, the Company's initial proposed overall increase to distribution revenues was $147,662,689, which represented a 13.2 percent increase in distribution revenue. Based on changes made during the proceeding,[2] NSTAR Electric now proposes a general increase in base distribution rates of $93,443,489, a transfer of $46,794,254 in revenues recovered through reconciling mechanisms, and an overall net increase of $140,237,743.[3]

NSTAR Electric also proposes to implement a performance-based ratemaking ("PBR") mechanism that would allow the Company to adjust its base distribution rates on an annual basis through the application of a revenue-cap formula (Exh. ES-CAH/DPH-1, at 13).

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1 The Company's filing includes new tariffs designed to recover the proposed revenue increase (Exh. ES-RDC-6, Schs. 1 (clean), 2 (redlined)).

2 In providing its updated revenue requirement schedules, the Company labeled them by date. For ease of reference, the Department refers to them by revision number. Thus, the April 24, 2022, update is Rev. 1; the June 24, 2022, update is Rev. 2; the August 5, 2022, update is Rev. 3; and the September 27, 2022, update is Rev. 4.

3 Minor discrepancies in any of the amounts appearing in this Order are due to rounding.

NSTAR Electric proposes a ten-year PBR plan, and to implement a set of performance metrics to evaluate the Company's performance during the PBR plan's term (Exh. ES-CAH/DPH-1, at 8-11, 13, 15).[4]

NSTAR Electric bases its proposed base distribution rate increase on a calendar test year of January 1, 2020 through December 31, 2020 (Exh. ES-REVREQ-1, at 12). NSTAR Electric was last granted an increase in electric base distribution rates in 2017. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05 (2017).[5] The Department docketed the instant petition as D.P.U. 22-22 and suspended the effective date of the tariffs until December 1, 2022, for further investigation.[6]

NSTAR Electric's service area comprises two geographic areas, designated as "EMA" (Eastern Massachusetts) and "WMA" (Western Massachusetts) (Exh. DPU 64-1, at 1). The service area designated as EMA encompasses the City of Boston and surrounding communities, extending west to Sudbury, Framingham, and Hopkinton, as well as

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4 NSTAR Electric's filing also contained proposals regarding the review and treatment of certain grid modernization investments and costs associated with the Company's resiliency tree work program. On March 9, 2022, the Department issued an Interlocutory Order and removed these proposals from consideration in this docket. D.P.U. 22-22, Interlocutory Order on Scope of Proceeding (March 9, 2022).

5 In D.P.U. 17-05, at 28-55, the Department approved the corporate consolidation of Western Massachusetts Electric Company with and into NSTAR Electric pursuant to G.L. c. 164, § 96. The legal name of Eversource Energy's electric distribution company in Massachusetts is NSTAR Electric Company d/b/a Eversource Energy.

6 The rates and charges established in this proceeding will be for electricity consumed on or after January 1, 2023.

communities in southeastern Massachusetts extending from Marshfield south through Plymouth, Cape Cod, and Martha's Vineyard, and west through New Bedford and Dartmouth (Exh. DPU 64-1, at 1). Within this geographic area, the Company serves approximately 1.2 million residential and commercial and industrial ("C&I") customers in approximately 80 communities (Exh. DPU 64-1, at 1). The service area designated as WMA encompasses the City of Springfield ("Springfield") and surrounding communities, extending west to the New York border and north to Greenfield and the Vermont border (Exh. DPU 64-1, at 1). Within this geographic area, the Company serves approximately 209,000 residential and C&I customers in approximately 59 communities (Exh. DPU 64-1, at 1).

II. PROCEDURAL HISTORY

On January 18, 2022, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E(a). On February 9, 2022, the Department granted the petition to intervene as a full party filed by the Massachusetts Department of Energy Resources ("DOER"). On February 15, 2022, the Department granted the petition to intervene as a full party filed by the Low-Income Weatherization and Fuel Assistance Program Network ("Low-Income Network"). On March 1, 2022, the Department granted the separate petitions to intervene as full parties filed by: (1) Acadia Center; (2) Cape Light Compact JPE ("Cape Light Compact" or "CLC"); (3) Conservation Law Foundation ("CLF"); (4) Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid ("National Grid (electric)"); (5) Northeast Clean Energy Council, Inc. ("NECEC"); and (6) The Energy Consortium ("TEC").

D.P.U. 22-22, Hearing Officer Ruling on Petitions for Intervention at 3-4 (March 1, 2022). On the same day, the Department allowed PowerOptions, Inc. ("PowerOptions") to participate as a limited intervenor. D.P.U. 22-22, Hearing Officer Ruling on Petitions for Intervention at 4-5 (March 1, 2022). The Department also allowed NRG Home f/k/a Reliant Energy Northeast LLC, Direct Energy Services, LLC, Direct Energy Business, LLC, Direct Energy Business Marketing, LLC, Green Mountain Energy Company, Energy Plus Holdings LLC, and XOOM Energy Massachusetts, LLC, and Walmart, Inc. ("Walmart") to participate as limited participants. D.P.U. 22-22, Hearing Officer Ruling on Petitions for Intervention at 5-6 (March 1, 2022).

On March 11, 2022, the Department allowed the University of Massachusetts ("UMass") to intervene as a full party. D.P.U. 22-22, Interlocutory Order on Appeals of Hearing Officer's Ruling on Petitions to Intervene by University of Massachusetts and Walmart, Inc. at 6-7 (March 11, 2022). On April 12, 2022, the Department allowed the Town of Barnstable ("Town" or "Barnstable") to participate as a limited intervenor. D.P.U. 22-22, Hearing Officer Ruling on Town of Barnstable Petition for Intervention at 4-6 (April 12, 2022).

Pursuant to notice duly issued, and consistent with certain ongoing safety measures and precautions relating to in-person events as a result of the COVID-19 pandemic, the Department held virtual public hearings on March 29, 2022, March 31, 2022, and May 4, 2022.[7] The Department held 14 days of virtual evidentiary hearings from June 29, 2022 through July 27, 2022.

In support of its filing, NSTAR Electric sponsored the testimony of the following witnesses, all of whom were employed by Eversource Service Company ("ESC"):[8] (1) Craig Hallstrom, president of regional electric operations for Connecticut and Massachusetts; (2) Douglas P. Horton, vice president of distribution rates and regulatory requirements; (3) Digaunto Chatterjee, vice president of system planning; (4) Lavelle A. Freeman, director of distribution system planning; (5) Gerhard Walker, principal engineer of system planning; (6) Penelope M. Connor, executive vice president of customer experience and energy strategy;[9] (7) Catherine Finneran, vice president of sustainability and environmental affairs; (8) Paul Renaud, vice president of engineering; (9) Robert W. Frank, former director of revenue requirements – Massachusetts;[10] (10) Ashley N. Botelho, director of revenue

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7 The Department received oral and written comments during the public comment period.

8 ESC performs functions such as accounting, auditing, communications, rates, legal, regulatory affairs, information technology, and human resources for NSTAR Electric and other Eversource Energy subsidiaries (Exhs. AG 1-26, Atts.). See also D.P.U. 17-05, at 163; NSTAR Gas Company, D.P.U. 19-120, at 269 (2020).

9 Prior to evidentiary hearings, the Department was advised that Ms. Connor no longer would participate in the proceedings. Her testimony, supporting exhibits, and responses to information requests were adopted by Jared Lawrence, senior vice president, customer operations and digital strategy and chief customer officer.

10 Prior to evidentiary hearings, Mr. Frank retired and his testimony, supporting exhibits, and responses to information requests were adopted by Ms. Botelho.

requirements – Massachusetts; (11) Sasha Lazor, director of compensation; (12) Michael P. Synan, director of benefits strategy and human resources shared services; (13) Leanne M. Landry, director of budget and investment planning; (14) John G. Griffin, director of corporate performance management;[11] (15) Jennifer A. Schilling, vice president of grid modernization; (16) William A. Van Dam, director of vegetation management; (17) Richard D. Chin, manager of rates; (18) Emilie O'Neil, assistant treasurer and director of corporate finance and cash management; (19) Elizabeth A. Foley, director of corporate performance management; and (20) Dennis Moore, information technology director of business solutions. NSTAR Electric also sponsored the testimony of the following external consultant witnesses: (1) Mark E. Meitzen, Ph.D., senior consultant at Laurits R. Christensen Associates, Inc.; (2) Nicholas A. Crowley, senior economist at Laurits R. Christensen Associates, Inc.; (3) Lawrence R. Kaufmann, Ph.D., president of LKaufmann Consulting, Inc. and senior advisor at Pacific Economics Group Research LLC and Black and Veatch Management Consulting; (4) Vincent V. Rea, managing director at Regulatory Finance Associates, LLC; (5) John J. Spanos, president of Gannett Fleming Valuation and Rate Consultants, LLC; and (6) Bruce R. Chapman, vice president at Christensen Associates Energy Consulting, LLC.

[11] Prior to evidentiary hearings, the Department was advised that Mr. Griffin no longer would participate in the proceedings. His testimony, supporting exhibits, and responses to information requests were adopted by Sean Noonan, vice president of the program management office and next-generation delivery.

The Attorney General sponsored the testimony of the following witnesses: (1) David E. Dismukes, Ph.D., consulting economist at Acadian Consulting Group; (2) David P. Littell, Esq., shareholder at Bernstein Shur Sawyer & Nelson; (3) David J. Effron, consultant; (4) David J. Garrett, managing member at Resolve Utility Consulting, PLLC; (5) Helmuth W. Schultz, III, senior regulatory consultant at Larkin & Associates, PLLC; (6) John Defever, regulatory consultant at Larkin & Associates, PLLC; (7) J. Randall Woolridge, professor of finance at the Pennsylvania State University; and (8) Timothy Newhard, financial analyst at the Attorney General's Office of Ratepayer Advocacy.

Cape Light Compact sponsored the testimony of John D. Wilson, research director at Resource Insight, Inc.; and Kevin F. Galligan, president of Galligan Energy Consulting, Inc. National Grid (electric) sponsored the testimony of Daniel R. Marceau, director of asset management and engineering performance, National Grid USA Service Company, Inc. TEC and PowerOptions jointly sponsored the testimony of James Bride, principal of Energy Tariff Experts, LLC. UMass sponsored the testimony of the following witnesses: (1) Eben Perkins, vice president at Competitive Energy Services, LLC; (2) Richard Silkman, Ph.D., chief executive officer at Competitive Energy Services, LLC; (3) Raymond Jackson, director of the physical plant division at the UMass Amherst campus; (4) James O'Day, director of utilities, energy management, and laboratories for facilities at the UMass Boston campus; and (5) James Jerue, associate vice chancellor of facility management at the UMass Dartmouth campus.

On August 19, 2022, the Attorney General, DOER, the Low-Income Network, Acadia Center, Cape Light Compact, CLF, National Grid (electric), TEC and PowerOptions, and UMass submitted initial briefs.[12] On September 2, 2022, the Company filed an initial brief. On September 19, 2022, the Attorney General, DOER, Acadia Center, Cape Light Compact, TEC and PowerOptions, and UMass submitted reply briefs. On the same day, the Low-Income Network and CLF each submitted a letter in lieu of a reply brief. On September 27, 2022, the Company filed a reply brief. The evidentiary record consists of approximately 4,000 exhibits and responses to 99 record requests.

III. COMPANY'S TEST YEAR

A. Introduction

NSTAR Electric's revenue requirement component is based on a test year ending December 31, 2020 (Exhs. ES-REVREQ-1, at 12; ES-REVREQ-2, Sch. 2 (Rev. 4)). The Company's test year coincides with the onset of the COVID-19 pandemic, a public health crisis that has been compared to the 1918 influenza pandemic.[13] The significant economic

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[12] The Attorney General filed a revised initial brief on August 24, 2022, to remove an errant header and add missing punctuation.

[13] In the 1918 influenza pandemic, an estimated 500 million people were infected globally (1/3 of the global population) with an estimated 50 million deaths, with 675,000 occurring in the U.S. https://www.cdc.gov/flu/pandemic-resources/1918-commemoration/1918-pandemic-history.htm. In the COVID-19 pandemic, an estimated 642 million people have been infected globally with an estimated seven million deaths, with over one million deaths occurring in the U.S. https://www.worldometers.info/coronavirus (last visited: November 18, 2022).

disruption associated with the pandemic has adversely affected individuals as well as businesses, particularly small businesses. Inquiries of the Department of Public Utilities regarding the COVID-19 Pandemic, D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 5 (December 31, 2020); D.P.U. 20-58, Order Opening Inquiry and Establishing Working Group at 2 (May 11, 2020).

The pandemic also has affected the financial position of jurisdictional electric, gas, and water distribution companies, and utilities throughout the country. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 5 (December 31, 2020). NSTAR Electric, as well as other utilities, face shifts in demand and usage, increased operational burdens, collections shortfalls, and voluntary and mandatory moratoriums on disconnections. These issues affect cash flow, which result in increased short-term borrowings amidst uncertain financial markets. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 5 (December 31, 2020).

B. Analysis and Findings

It is well-established Department precedent that base distribution rate filings are based on an historic test year, adjusted for known and measurable changes. NSTAR Gas Company, D.P.U. 14-150, at 45 (2015); Investigation into Rate Structures that Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A at 52-53 (2008); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); see also Massachusetts Electric Company v. Department of Public Utilities, 383 Mass. 675, 680 (1981). In establishing rates pursuant to

G.L. c. 164, § 94, the Department examines a test year on the basis that the revenue and expense figures adjusted for known and measurable changes, and rate base figures during that period, provide the most reasonable representation of a distribution company's present financial situation, and fairly represent its cost to provide service. Plymouth Water Company, D.P.U. 14-120, at 9 (2015); Ashfield Water Company, D.P.U. 1438/1595, at 3 (1984).

The selection of the test year is largely a matter of a distribution company's choice, subject to Department review and approval. Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 145-146 (2016), citing D.P.U. 07-50-A at 51; Boston Edison Company, D.P.U. 1720, Interlocutory Order at 7-11 (January 17, 1984). The Department requires that the historic test year represent a twelve-month period that does not overlap with the test year used in a previous rate case unless there are extraordinary circumstances that render a previous Order confiscatory. D.P.U. 14-150, at 45 n.26; Massachusetts Electric Company, D.P.U. 19257, at 12 (1977). The test year is generally the most recent twelve-month period for which financial information exists. D.P.U. 14-150, at 45 n.26; Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 24, cert. denied, 439 U.S. 921 (1978). The Department has a strong preference for calendar test years. D.P.U. 17-05, at 28; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 22 (2016); D.P.U. 14-120, at 16 & n.11.

In this case, the Company has selected a calendar 2020 test year. No party has objected to the Company's selected test year. While the use of a different test year, such as a split test year,[14] may have mitigated some of the effects of the pandemic on the Company's rate filing, the societal and financial effects of the pandemic remain ongoing. Moreover, the use of an earlier test year such as 2019 for a rate increase that would take effect in 2023 would be fraught with its own challenges given the staleness of the data. On this basis, the Department concludes that there is no reasonable alternative test year that would insulate NSTAR Electric's operations from the effects of the pandemic.[15]

The Company has made numerous adjustments to its test-year revenues, expenses, and plant in preparing its rate filing (Exhs. ES-REVREQ-1, at 13-14; ES-REVREQ-2, Schs. 7, 9 (Rev. 4)). Such adjustments are a routine part of rate case proceedings. In reviewing these adjustments, the Department recognizes that some year-to-year variation is expected, even when comparing individual functions and accounts over corresponding time periods. Boston Gas Company, D.P.U. 20-120, at 16 (2021). As discussed in Section VII.H below, the Company has been deferring incremental expenditures related to COVID-19 response efforts (Exhs. ES-REVREQ-2, Sch. 9, at 1 (Rev. 4); DPU 3-2; AG 21-1, Att.; AG 1-34, Att. (h)

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14 A test year that spans two calendar years, as opposed to a test year based on a calendar year, is often referred to as a "split" test year. D.P.U. 14-150, at 45 n.26; D.P.U. 14-120, at 12, 16. A test year, whether a calendar year test year or a "split" test year, comprises a period of twelve consecutive calendar months.

15 In rare cases, the Department has relied on different test years than those proposed by the utility. McNamara Water System, D.P.U. 91-196, at 4-5 (1992); Hutchinson Water Company, D.P.U. 85-194, at 3-4 (1986). In these cases, however, the petitioners' cases-in-chief consisted of a few pages of prefiled testimony from a single witness. In contrast, NSTAR Electric's own case-in-chief consists of thousands of pages of prefiled testimony and exhibits from over 20 witnesses.

at 7, Att. (i) at 5). To the extent that the pandemic continues to affect the Company's operations, such as in lower C&I revenues, increased write-offs, and ongoing COVID-19 response expenditures, these issues are fully addressed in the respective sections of this Order.

Based on the foregoing analysis, the Department finds that while the effects of the pandemic upon NSTAR Electric's operations have added to the intricacies of the Company's rate filing, the Company's proposed test year is nonetheless reviewable and reliable. Therefore, the Department accepts NSTAR Electric's selection of a calendar year 2020 test year.

IV. PERFORMANCE BASED RATEMAKING PROPOSAL

A. Introduction

In D.P.U. 17-05, at 370-414, the Department approved a PBR mechanism with a five-year term for the Company. The PBR mechanism allowed NSTAR Electric to adjust its distribution rates annually through the application of a revenue-cap formula that accounts for, among other factors, inflation and events beyond the Company's control that have a significant effect on its revenue requirement ("exogenous events"), either positive or negative. D.P.U. 17-05, at 381-399. The PBR mechanism included a productivity offset, or "X factor," of -1.56 percent. D.P.U. 17-05, at 381-392. Further, the PBR mechanism included a 25-basis point (or 0.25 percent) consumer dividend as a deduction to the adjustment when inflation exceeded two percent. D.P.U. 17-05, at 394-395. The PBR mechanism also included an earnings-sharing mechanism ("ESM") that incorporated a

200-basis point threshold above the Company's authorized return on equity ("ROE") of 10.0 percent. D.P.U. 17-05, at 399-401, 713.[16]

As discussed in further detail below, in the instant proceeding, the Company proposes to renew its PBR plan with certain modifications. In its initial filing, NSTAR Electric proposed a PBR mechanism with a revenue cap formula and the following components: (1) a ten-year term with a five-year, mid-term "rate schedule filing" to meet the requirements of G.L. c. 164, § 94; (2) an X factor of -1.45 percent; (3) an annual inflation index based on the Gross Domestic Product Price Index ("GDP-PI");[17] (4) a proposed consumer dividend to provide a "stretch factor," applicable when inflation equals or exceeds two percent; (5) a rate base roll-in for 2021 and 2022 capital investments; (6) an ROE risk factor ("ROERA") triggered by significant changes up or down in Treasury rates; (7) cost treatment in the second five years of the PBR plan for critical infrastructure; (8) an ESM consistent with that approved for affiliate NSTAR Gas Company ("NSTAR Gas") in NSTAR Gas Company, D.P.U. 19-120 (2020); and (9) an exogenous cost provision that, in particular, would allow

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16 If the Company's calculated, earned distribution ROE was at or below the threshold (i.e., 12.0 percent), the Company was not required to share any earnings. D.P.U. 17-05, at 401. If the Company's earned distribution ROE exceeded the threshold, shareholders and ratepayers shared any earnings above the threshold at 25 percent and 75 percent, respectively. D.P.U. 17-05, at 401.

17 GDP-PI is a measure of inflation in the price of goods and services produced in the United States published quarterly by the U.S. Department of Commerce, Bureau of Economic Analysis.

for recovery for certain property tax and information technology ("IT") expenses (Exhs. ES-CAH/DPH-1, at 13, 62-93; ES-PBR/PLAN-1, at 4-14).

The Company's initial filing also included an alternative PBR plan proposal, which was modified during the proceeding (Exhs. ES-CAH/DPH-1, at 93; DPU 1-1; DPU 5-1). NSTAR Electric proposed that, for a five-year term, the following modifications would apply: (1) only capital additions completed through December 31, 2021 would be eligible for a rate-base roll-in and those additions would be included in base distribution rates set in this proceeding; (2) the ROERA would not apply;[18] (3) the ESM would be asymmetrical with upside sharing for customers but no downside adjustment for the Company (Exh. DPU 1-1). The remaining proposed PBR mechanism components applicable to a ten-year PBR term would apply to a five-year term (Exhs. ES-CAH/DPH-1, at 93; DPU 1-1; DPU 5-1).

As part of its rebuttal testimony, the Company revised its initial proposed PBR mechanism to address concerns raised by the Attorney General (Exh. ES-PBR-Rebuttal-1, at 41-50). The Company still proposed a revenue cap formula with a ten-year PBR plan term, but the initial proposal was modified to: (1) reduce the X factor to zero; (2) increase the consumer dividend; (3) cap eligible inflation as tracked by GDP-PI to five percent; (4) eliminate the cost treatment for the critical infrastructure; (5) eliminate the proposed

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18 In Exhibit DPU 5-1, the Company stated that the ROERA would apply to a PBR plan with a five-year term. On brief, however, when summarizing the components of a five-year term, the Company did not include the ROERA in the proposal (see, e.g., Company Brief at 16 n.2, 19 n.6). In any event, as discussed in Section IV.D.5.f below, the Department disallows the proposed ROERA.

roll-in of 2022 capital additions; and (6) implement a "K-bar" formula approach (see n.21 below) for capital investment support between rate cases, beginning January 1, 2024, the date of the first PBR adjustment (Exh. ES-PBR-Rebuttal-1, at 45).[19] The Department discusses these proposals below.

B. PBR Mechanism Components

1. PBR Plan Term

The Company initially proposed a ten-year PBR term with a mid-term filing of rate schedules at the five-year mark (Exhs. ES-CAH/DPH-1, at 13, 93; ES-PBR/PLAN-1, at 13). Alternatively, the Company proposed a five-year plan term, with certain modifications to the ratemaking mechanisms (Exhs. ES-CAH/DPH-1, at 93; DPU 1-1; DPU 5-1). As noted above, during the proceedings the Company revised certain components of its proposed PBR plan. The Company, however, did not revise the term of its PBR plan and proposed to maintain the ten-year term (Exh. ES-PBR-Rebuttal-1, at 45).

2. Productivity Offset

The Company initially proposed a productivity offset, or X factor to be calculated as:

$X = [(\% \ TFP^{R}_{1} - \% \ TFP_{E}) + (\% \ W_{E} - \% \ W_{1})$, where

$\% \ TFP^{R}_{1}$ is the percentage change in electric distribution industry total factor productivity growth;

19 As discussed in Section V.B below, the Company also proposed a set of performance metrics to be implemented in conjunction with the PBR plan. The proposed PBR metrics are the same under both the initially proposed PBR plans (i.e., the plan with a ten-year or five-year term) and the revised proposed PBR plan with a ten-year term.

% TFP_E is the percentage change in economy wide total factor productivity growth;

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

% W_1 is the percentage change in electric distribution industry input price growth.

(Exh. ES-PBR/TFP-1, at 15).

The X factor consists of a differential in a measure of the expected rate of productivity change between the electric distribution industry and the overall economy, and a differential in input price growth between the overall economy and the electric distribution industry (Exh. ES-PBR/TFP-1, at 12). To determine the proposed X factor, the Company conducted a productivity study of U.S. electric distribution total factor productivity ("TFP") and input price growth over the period 2006 through 2020 (Exh. ES-PBR/TFP-1, at 20). The Company used two different samples for its productivity study: (1) a sample of 65 electric distribution companies ("EDCs") intended to represent the overall U.S. electric distribution industry ("nationwide EDCs"); and (2) a sample of 17 EDCs intended to represent the electric distribution industry in the Northeast U.S. ("regional EDCs") (Exh. ES-PBR/TFP-1, at 20). For economy-wide TFP and input price growth, the Company used official U.S. government sources (Exh. ES-PBR/TFP-1, at 20).

The TFP is generally defined as the ratio of total output to total input (Exh. ES-PBR/TFP-1, at 13). Total output consists of all the services produced by the relevant unit of production (Exh. ES-PBR/TFP-1, at 13). Total input includes all resources used by the unit of production in providing those services (Exh. ES-PBR/TFP-1, at 13). The Company used number of customers as the sole productivity study output measure

(Exh. ES-PBR/TFP-1, at 13). The Company constructed a quantity index of total input for each firm and each year based on capital, labor, and materials (Exh. ES-PBR/TFP-1, at 13). The Company has also incorporated customer accounts and sales expenses and administrative and general costs into the TFP model (Exh. ES-PBR/TFP-1, at 17).

The results of the Company's study indicate that, for the period 2006 through 2020, the average growth in productivity for the regional EDCs was equal to -0.05 percent, while the average productivity growth for the nationwide EDCs was equal to 0.06 percent (Exh. ES-PBR/TFP-1, at 24-25). For the same period, the average input price growth for regional EDCs was equal to 3.11 percent, while the average input price growth for the nationwide EDCs was equal to 3.17 percent (Exh. ES-PBR/TFP-1, at 24-25). The Company's productivity study indicates that the economy-wide average productivity growth from 2006 through 2020 was 0.34 percent, and the average input price growth was 2.0 percent (Exh. ES-PBR/TFP-1, at 23).

The Company calculated its proposed productivity offset using the productivity and input price growth indices for the nationwide EDCs rather than the regional EDCs (Exh. ES-PBR/TFP-1, at 27). Inputting the results of the productivity study into the productivity formula, the Company calculated a proposed X factor of -1.45 percent (Exh. ES-PBR/TFP-1, at 24).

As noted above, during the proceeding, the Company proposed to modify certain components of the proposed PBR plan (Exh. ES-PBR-Rebuttal-1, at 44-45). In particular, the Company proposed to reduce the X factor to zero, as recommended by the Attorney

General (Exh. ES-PBR-Rebuttal-1, at 44-45, citing Exhs. AG-DED-PBR-1, at 3, 58; AG-DPL-1, at 12).

3. Inflation Index and Floor

The Company initially proposed to base the price inflation index included in the revenue cap formula on the GDP-PI as measured by the U.S. Commerce Department (Exhs. ES-CAH/DPH-1, at 67; ES-PBR/PLAN-1, at 5). 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. ES-CAH/DPH-1, at 67; ES-PBR/PLAN-1, at 5). 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 (Exhs. ES-CAH/DPH-1, at 67; ES-PBR/PLAN-1, at 5). Additionally, the Company proposed an inflation "floor" equivalent to the X factor of -1.45 percent so that a negative PBR adjustment would not occur (Exh. ES-CAH/DPH-1, at 68).

In its rebuttal testimony, the Company proposed to modify the requested inflation factor. Specifically, NSTAR Electric proposed to cap the factor at five percent, and the Company stated that it would "make sense" to have the opportunity to file a base distribution rate case if reported earnings fall more than 400 basis points below the ROE authorized in the instant proceeding (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 35-1).

4. Consumer Dividend

The Company initially proposed to include a consumer dividend of 15 basis points, or 0.15 percent, when inflation, as calculated in the proposed PBR formula, exceeds two percent (Exhs. ES-CAH/DPH-1, at 72; ES-PBR/PLAN-1, at 38). The Company stated that its proposed consumer dividend was intended to share the financial benefits of increased productivity growth with customers, and that the continuance of an existing PBR plan warrants a lower consumer dividend than at the outset of a PBR plan (Exhs. ES-CAH/DPH-1, at 73; ES-PBR/PLAN-1, at 37, 44).

In its rebuttal testimony, the Company proposed to modify the requested consumer dividend. Specifically, the Company proposed to raise the consumer dividend to 25 basis points, or 0.25 percent, when inflation exceeds two percent (Exh. ES-PBR-Rebuttal-1, at 45).

5. Post-Test-Year Capital Additions

The Company initially proposed to include post-test-year capital additions into base distribution rates at two different intervals during the term of the proposed PBR plan (Exh. ES-CAH/DPH-1, at 74-75). First, the Company proposed that the base distribution rates effective January 1, 2023, would include in rate base plant additions placed into service through December 31, 2021 (Exh. ES-CAH/DPH-1, at 74-75). 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 ending December 31, 2021 (Exh. ES-CAH/DPH-1, at 75). Second, the Company proposed as part of the first annual PBR plan filing for rates effective January 1, 2024, to include in rate base the calendar year 2022 capital additions along with the associated accumulated depreciation (Exh. ES-CAH/DPH-1, at 75).[20]

In its rebuttal testimony, the Company modified its capital roll-in proposal. Specifically, the Company proposed to eliminate the roll-in of the 2022 calendar year capital additions from the first annual PBR plan filing (Exh. ES-PBR-Rebuttal-1, at 45). Further, the Company proposed as part of the revised PBR formula, a K-bar adjustment[21] that would allow additional revenues to be collected through the PBR adjustments, beginning January 1, 2024, to provide additional funding for capital investments (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 63-3 & Atts.; RR-DPU-12 & Atts.). The K-bar approach would establish a level of eligible capital recovery based on a historical average of capital additions that went into service under operation of the Company's current PBR plan, approved in D.P.U. 17-05, for the years in which that I-X factor was applicable, escalated to current year dollars

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20 As noted above, under a five-year PBR plan, the Company proposed to roll-in only capital additions placed in service through December 31, 2021, and those additions would be included in base distribution rates set in this proceeding (Exh. DPU 1-1).

21 In 2016, the Alberta Utilities Commission ("AUC") developed a "K-bar" approach to supplemental capital funding for Alberta electric distribution utilities (Exh. DPU 35-5, at 3, citing AUC docket 20414-D01-2016 (December 16, 2016)). The AUC amended its K-bar method in 2018 (Exh. DPU 35-5, at 3, citing AUC docket 22394-D01-2018, (February 5, 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. DPU 35-5, at 3-4). 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. DPU 35-5, at 4). The AUC calls this differential the "K-bar" (Exh. DPU 35-5, at 4).

(RR-DPU-12). Specifically, under the Company's revised proposal, the K-bar revenue requirement would be calculated by rolling forward 2018 through 2022 plant additions, cost of removal, and retirements that occurred during the current PBR plan and then calculating a revenue requirement based on that theoretical rate base calculation (RR-DPU-12). The K-bar revenue requirement is then compared to the capital investment costs approved in the instant proceeding and adjusted to 2023 costs using the PBR mechanism approved in the instant proceeding to establish the incremental K-bar revenue support (RR-DPU-12).

6. ROERA Factor

The Company initially proposed to include in the PBR plan an ROERA mechanism to recover costs arising from changes in the capital markets during the ten-year PBR term (Exhs. ES-CAH/DPH-1, at 76; ES-PBR/PLAN-1, at 8). The ROERA would be triggered, and a rate adjustment would take place, if the yield on the ten-year Treasury bond reaches 200 basis points above or below the yield in effect at the start of the PBR plan (Exh. ES-CAH/DPH-1, at 76-77). The Company states that the ROERA adjustment would apply only to rate base approved at the outset of the PBR plan and not for additions made while the PBR plan is in effect (Exh. ES-PBR/PLAN-1, at 12).

The proposed adjustment would take place in accordance with the following formula:

$CAP(t) = [RB(t)*EQ_0 *(TB(t)-TB_0)] / (1-CT_0)$

$CAP(t)$ is the capital cost adjustment in year t

RB_0 is the rate base in year zero (i.e., the outset of the PBR plan)

EQ_0 is equity's share of rate base in year zero

TB (t) is the yield to maturity on the ten-year Treasury bond in year t

TB_0 is the yield to maturity on the ten-year Treasury bond in year zero

CT_0 is the combined tax rate in year zero

(Exh. ES-PBR/PLAN-1, at 11-12).

As noted above, if a five-year PBR plan term is approved, the Company proposed that the ROERA would not apply (Exh. DPU 1-1). In its rebuttal testimony, the Company did not propose to revise or remove the proposed ROERA from the revised PBR plan (Exh. ES-PBR-Rebuttal-1, at 45).

7. Cost Treatment of Critical Infrastructure

In its initial filing, NSTAR Electric stated that forecasted customer demand and incremental electrification demand over the PBR term will necessitate the Company to make major critical infrastructure investments (Exh. ES-CAH/DPH-1, at 77). In particular, NSTAR Electric stated that it intended to complete "major infrastructure projects," including substations and new circuits across the Company's service territory, over the next ten years at an estimated cost of $956 million (Exhs. ES-CAH/DPH-1, at 79-80; ES-ENG-3). The Company stated that it could not commit to a ten-year PBR term without a plan for cost treatment of the revenue requirement associated with these projects (Exh. ES-CAH/DPH-1, at 81). Thus, the Company initially proposed as part of its PBR plan to file for recovery of these costs at three specific intervals over the course of the ten-year PBR term (Exh. ES-CAH/DPH-1, at 82). Under this proposal, the Company would collect the revenue requirement associated with project costs that are reviewed and approved by the Department through a factor included in the PBR mechanism (Exh. ES-CAH/DPH-1, at 82-83).

In its rebuttal testimony, the Company proposed to eliminate the specific cost recovery factor associated with the aforementioned critical infrastructure projects (Exh. ES-PBRRebuttal-1, at 45). Instead, the Company proposed to receive investment support for the costs associated with these projects through the proposed K-bar adjustment (Exh. ES-PBR-Rebuttal-1, at 45).

8. ESM

The Company initially proposed to adopt an ESM consistent with the design approved for NSTAR Gas in D.P.U. 19-120 (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). 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 ROE exceeds 100 basis points above the ROE authorized in this proceeding (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE is between 150 and 200 basis points below the authorized ROE, sharing with customers would be triggered on a 50/50 percent basis (50 percent to ratepayers and 50 percent to shareholders) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE exceeds 200 basis points below the authorized ROE, sharing with customers would be triggered on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). 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's adjustment would be excluded from the calculation of the subsequent year's sharing (Exh. ES-CAH/DPH-1, at 91). The Company acknowledged that any ESM adjustment would be subject to a full investigation in an adjudicatory proceeding (Exh. ES-CAH/DPH-1, at 92).

As noted above, if a five-year PBR term is approved, the ESM would be asymmetrical with upside sharing for customers, but no downside adjustment for the Company (Exh. DPU 1-1). In its rebuttal testimony, the Company did not propose to revise or remove the proposed ESM from the revised ten-year PBR plan (Exh. ES-PBR-Rebuttal-1, at 45).

9. Exogenous Cost Factor

NSTAR Electric initially proposed to include in the PBR adjustment formula an exogenous cost provision (or "Z factor"), which was defined as positive or negative changes to operating costs that are beyond the Company's control and not reflected in the GDP-PI or other elements of the PBR adjustment formula (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7). The Company would calculate the exogenous cost factor as a percentage of the previous year's base revenues (Exh. ES-CAH/DPH-1, at 83).

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 distribution industry as opposed to the general economy; and (4) meet a threshold of “significance” for qualification (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Company anticipated two types of future costs that might apply for exogenous cost recovery: (1) incremental property taxes arising from a municipality’s change in valuation method for assessing utility property; and (2) expenses incurred for certain Enterprise IT investments (Exh. ES-CAH/DPH-1, at 85-86). The Company proposed the significance threshold for exogenous costs to be set at $4 million in 2023 and adjusted annually by the change in GDP-PI, except for exogenous costs associated with Enterprise IT expenses, for which the initial threshold would be set at $6 million (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Company did not revise this aspect of the proposed PBR mechanism during the proceedings.

C. Positions of the Parties

1. Attorney General

The Attorney General raises a number of issues with the Company’s initially proposed, and modified, PBR plans. First, the Attorney General argues that the Company’s TFP results and resulting initially-proposed X factor are flawed (Attorney General Brief at 26). In particular, the Attorney General contends that the X factor approved in D.P.U. 17-05 has resulted in over-collection of $124 million in the past five years and, despite the Company’s efforts to improve the TFP study in this proceeding, there is no accounting for this over-collection (Attorney General Brief at 26-27). The Attorney General also claims that NSTAR Electric’s initially proposed X factor of -1.45 percent is overstated because the TFP study did not exclude costs that the Company proposes to remove from the base rate revenue requirement and the PBR formula (Attorney General Brief at 27-30, citing Exh. ES-RDC-6, Sch. 1, at 127, 452-454; Tr. 4, at 323-327; RR-AG-8).[22] Further, the Attorney General asserts that the TFP study is not robust and, therefore, produces hypersensitive and exaggerated results (Attorney General Brief at 30). In addition, the Attorney General contends that the TFP study and resulting X factor are unreliable because the study inappropriately relies on customer count as an output, which she asserts is not an accurate indicator of cost causation (Attorney General Brief at 30-33).

Second, the Attorney General challenges the Company's benchmarking study and initially proposed consumer dividend of 0.15 percent (Attorney General Brief at 33-36). The Attorney General argues that the limited time frame of NSTAR Electric's benchmarking study (i.e., 2018 through 2020) produces more favorable results for the Company than would a more robust study that uses a longer time frame and more data points (Attorney General Brief at 33). In this regard, she contends that the longer time frame used in her witness's benchmarking study, which resulted in a consumer dividend of 0.25 percent, provides the Department with a more accurate comparison between NSTAR Electric's investment and cost performance and the Company's peers (Attorney General Brief at 33-34, citing Exh. AG/DED-4, Schs. 4, 5). Further, the Attorney General claims that the Company's lack

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22 These costs include those associated with energy efficiency, grid modernization and capital additions, advanced metering infrastructure, storm restoration, vegetation management, pension and post-retirement benefits other than pensions, substation capital additions, customer information systems, and IT additions (Attorney General Brief at 29).

of specific and measurable results to show improved efficiency, and the malleability of the Company's benchmarking study, are indicative of a misalignment with long-standing Department precedent (Attorney General Brief at 35-36, citing Incentive Regulation, D.P.U. 94-158, at 63 (1995)). Accordingly, the Attorney General recommends that the Department reject the initially proposed consumer dividend of 0.15 percent and adopt a 0.25-percent consumer dividend, in the event that the Department approves a PBR plan for the Company (Attorney General Brief at 35).

Third, the Attorney General argues that the Company's proposed K-bar adjustment will result in additional rate increases under the proposed PBR plan and will provide little incentive for cost control (Attorney General Brief at 23). Further, the Attorney General contends that a K-bar structured with a historical average based on the years 2018 through 2022 is flawed, because 2022 capital additions have not been subject to prudency review and the Company could improperly increase 2022 spending as a means to increase its future revenue under its K-bar (Attorney General Brief at 24). The Attorney Generals also claims that there is uncertainty regarding the historical capital plant additions used by NSTAR Electric to calculate its proposed K-bar formula (Attorney General Brief at 25). She asserts that NSTAR Electric's proposed K-bar adjustment includes $114 million in additional capital for the years 2018-2019 that was not reflected in the Company's TFP calculations (Attorney General Brief at 25). Based on these considerations, the Attorney General argues that, if the Department approves a PBR plan for the Company, a K-bar structured with a historical average from the years 2017 through 2021 is the more appropriate option (Attorney General Brief at 24, 65).[23]

Fourth, the Attorney General raises concerns regarding the Company's proposed ROERA. In particular, the Attorney General argues that the proposed ROERA is unnecessary, as the Company already is compensated for changes in O&M expenses and capital costs via the annual rate increases provided by the I-X formula (Attorney General Brief at 36). Further, the Attorney General contends that the proposed ROERA is an attempt to expand the well-established definition of what qualifies as an exogenous cost event and allowing this adjustment along with a Z factor will dilute the original purpose behind "truly exogenous events" (Attorney General Brief at 37, citing D.P.U. 17-05, at 395-396). In addition, the Attorney General claims that the Company failed to provide any support for using the ten-year U.S. Treasury bond in calculating the ROERA adjustment, while the Attorney General's witnesses established that the 30-year U.S. Treasury Bond yield is a better representation of the long-run expectations of investors (Attorney General Brief at 38, citing Exhs. AG-JRW-1, at 13, 18, 58; ES-VVR-1, at 16, 17, 26, 55; ES-VV-5, at 1; Tr. 9, at 1012-1013). For these reasons, the Attorney General recommends that the Department reject the Company's proposed ROERA adjustment (Attorney General Brief at 38).

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23 The Attorney General contends that the 2017 through 2021 average includes an additional $82 million in capital additions not reflected in the Company's TFP calculations (Attorney General Brief at 25).

Fifth, the Attorney General acknowledges that the Company needs to carefully undertake its future distribution system planning to accommodate the Commonwealth's emissions reduction goals and clean energy requirements (Attorney General Brief at 57). The Attorney General, however, argues that the Company's critical infrastructure projects are loosely defined and are only in the early stages of planning (Attorney General Brief at 58). Further, she contends that the circumstances surrounding when the Company could seek cost recovery for these projects are vague, lack meaningful restrictions or requirements, and present oversight challenges (Attorney General Brief at 58-59). Finally, the Attorney General argues that NSTAR Electric's proposal is unnecessary because legislative action already requires the Company to make various investments in reliability, resiliency, and general electrification and there likely will be overlap between these requirements and the Company's proposed capital investments (Attorney General Brief at 59, citing An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, § 53, ("2022 Clean Energy Act")). For these reasons, the Attorney General asserts that the Company's initial proposal to include a cost recovery factor for critical infrastructure investments should be rejected (Attorney General Brief at 59).

Sixth, the Attorney General argues that the Department should reject the Company's proposed inclusion of certain Enterprise IT expenses in the exogenous cost factor (Attorney General Brief at 59). In support of this argument, the Attorney General contends that ESC, rather than the Company, will incur the costs for most of these investments (Attorney General Brief at 59). Further, she claims that the Company already is compensated for IT costs through base distribution rates and the annual PBR adjustments (Attorney General Brief at 60). In addition, the Attorney General asserts that the Company does not recognize or net out any economic benefits that accrue as a result of the implementation of the new IT systems (Attorney General Brief at 60).

Next, the Attorney General makes several arguments, in the context of the proposed PBR plan and annual PBR adjustment, against the Company's request to transfer the Solar Expansion Program investments to base distribution rates (Attorney General Brief at 113-117, citing Exh. AG-TN-1, at 4-10).[24] In particular, she contends that the Company's proposal would provide a windfall to shareholders because the amounts collected from customers for the Solar Expansion Program investments would increase over time due to the PBR adjustment while the actual costs to the Company for those investments would decrease as the Company recovers its investment (Attorney General Brief at 113-116, citing Exh. AG-TN-1, at 4-8). Further, the Attorney General argues that the Solar Expansion Program costs are generation costs, not distribution costs (Attorney General Brief at 116-117, citing Exh. AG-TN-1, at 9). Thus, according to the Attorney General, these costs should not be included in the base distribution rate revenue requirement portion of the PBR rate formula and applying a PBR adjustment to these generation-related costs would be inappropriate (Attorney General Brief at 117, citing Exh. AG-TN-1, at 9-10).

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24 The Attorney General raised similar arguments as to the Company's proposed SMART Program investments and Solar Program investments (Attorney General Brief at 113-117). The Department addresses these programs and the treatment of the investments in Section XIV below.

Finally, the Attorney General argues that numerous provisions in the Company's proposed PBR plan tariff should be revised to provide appropriate definitional and clarifying language (Attorney General Brief at 60-61). She asserts that each of her recommended changes should be adopted should the Department allow a PBR plan for the Company (Attorney General Brief at 61).

Based on the above considerations, the Attorney General argues that the Company's proposed PBR plans will impose unnecessary rate increases on customers and focus too heavily on meeting projected increased peak demand through increased capital expenditures (Attorney General Brief at 14-15, 18-26, 62-64). Thus, the Attorney General asserts that the Department should reject the PBR plan in lieu of an all-in capital tracker (Attorney General Brief at 10, 64-65; Attorney General Reply Brief 1-3). According to the Attorney General, the all-in capital tracker would: (1) fully compensate the Company for investments that the Company actually makes; (2) be simple to understand, account for, and administer; (3) consolidate into one filing all other capital costs currently being recovered through reconciling mechanisms; (4) incorporate the required cost recovery without additional filings for legislatively-mandated investments (Attorney General Brief at 8-10). Further, the Attorney General asserts that the Department has successfully used capital trackers in the past (Attorney General Brief at 9, citing D.P.U. 15-80/D.P.U. 15-81, at 44–55; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 78-84 (2009)). Alternatively, if the Department approves a PBR plan for the Company, the Attorney General asserts that the plan should include the following modifications: (1) an X factor equal to zero; (2) a consumer dividend of at least 25 basis points; (3) a cap on the inflation factor of five percent; (4) inclusion of a K-bar formula approach based on average historical capital expenditures for the five-year period of 2017 through 2021, and elimination of the 2022 capital roll-ins; and (5) elimination of the critical infrastructure cost recovery factor and exogenous cost treatment for Enterprise IT expenses (Attorney General Brief at 65).

2. DOER

DOER recommends approving a PBR plan for the Company, but with modifications (DOER Brief at 9-10). First, DOER argues that the Department should approve a five-year plan term and reject the Company's proposed ten-year term (DOER Brief at 9-10). DOER asserts that a ten-year PBR plan would carry significant risk and that it would inhibit the ability of regulators and legislators to ensure that rates are aligned with the needs of the clean energy transition (DOER Brief at 10-11). Further, DOER argues that the Company's involvement with multiple large-scale investment proceedings necessitates a shorter-term length so that ratemaking structures can be responsive to the needs of the clean energy transition (DOER Brief at 11-12). DOER also contends that NSTAR Electric's assumptions in modeling demand growth may require revision in the future and that a five-year term would better allow the Company and Department to adjust planned investments as needed (DOER Brief at 13). Additionally, DOER claims that a five-year term is more consistent with Department precedent (DOER Brief at 10). Finally, DOER asserts that the elimination of full revenue decoupling will need to be addressed in the near future, and that a five-year term will enable the Company to be more responsive to this change than a ten-year term would be (DOER Brief at 13-14).

Second, DOER supports the Attorney General's proposal for a broad-based capital tracker mechanism to support the Company's critical infrastructure projects as an interim measure while a more fully developed and vetted K-bar formula can be developed (DOER Brief at 15-16; DOER Reply Brief at 4-5). DOER argues that the creation of multiple capital trackers and recovery mechanisms for the Company's investments is a non-sustainable practice (DOER Brief at 15). Rather, DOER contends that a formulaic approach with built-in cost containment mechanisms and performance incentives is an appropriate long-term solution to increasing capital investment demand (DOER Brief at 16-17).

Finally, DOER argues that the Department should modify the Company's initial proposed PBR to reduce rate shock for customers (DOER Brief at 17). In this regard, DOER supports the Company's revised proposal to cap the inflation factor in its PBR formula at five percent (DOER Brief at 17-18).

3. Acadia Center

Acadia Center argues that the Department should reject the Company's proposed ten-year PBR term and instead approve a five-year term, as this structure is more appropriate in light of the expected substantial capital investments over the next five years (Acadia Center Brief at 10-11, citing D.P.U. 20-120; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150 (2019)). Further, Acadia Center contends that the Company has acknowledged the significant risks involved with a ten-year PBR plan, including unprecedented investment in climate adaptation and electrification (Acadia Center Brief at 12).

Acadia Center also argues that NSTAR Electric's current PBR plan, and specifically the negative X factor, has resulted in a financial windfall for the Company (Acadia Center Brief at 13). Acadia Center contends that the negative X factor is nationally unprecedented and reflects declining performance, which, in turn, provides little incentive for the Company to address its productivity issues (Acadia Center Brief at 13-14). Acadia Center asserts that utility compensation should be distinctively linked to measurable performance outcomes that benefit customers, and, therefore, the Department should reject a negative X factor in this proceeding (Acadia Center Brief at 14).

4. Cape Light Compact

Cape Light Compact argues that a ten-year PBR plan term would be too long given the likelihood of significant change in the electric industry in that timeframe (e.g., advanced metering, electrification) and the need to address other issues in the Company's next base distribution rate case (e.g., eliminating full revenue decoupling, continuing consolidation of EMA and WMA rates) (CLC Brief at 38; CLC Reply Brief at 12). Cape Light Compact also contends that NSTAR Electric's proposal to file "rate schedules" at the five-year point is unclear, as the Company does not specify what that filing would entail (CLC Brief at 38, citing Exhs. DPU 5-1; CLF 1-1). In addition, Cape Light Compact supports the Attorney General's recommendation for an all-in capital tracker (CLC Reply Brief at 10-11). According to Cape Light Compact, an all-in capital tracker offers the most balanced approach for ratepayers and the Company, allows appropriate regulatory review and cost recovery, provides a more straightforward, easily understood alternative to PBR, and is administratively efficient (CLC Reply Brief at 10-11, citing Attorney General Brief at 8-9).

5. CLF[25]

CLF argues that the Company's proposed ten-year PBR plan term is unreasonably long and may prohibit necessary review in the future (CLF Brief at 5). Thus, CLF contends that the Company should conduct additional review and cost analysis to provide more accurate depictions of electrification costs over the next several years and should seek Department approval of moderate changes to base distribution rates as they become necessary (CLF Brief at 5). Further, CLF argues that the Company's proposed PBR plan is not in the public interest as it fails to limit recovery to reasonable costs and is insufficient to meet the ratemaking principles of fairness and equity (CLF Brief at 12-13). Accordingly, CLF recommends that the Department deny the Company's proposed PBR plan (CLF Brief at 5). Alternatively, if the Department approves a PBR plan for the Company, CLF recommends certain modifications (CFL Brief at 5). In particular, CLF argues that the Department should not approve rate increases associated with NSTAR Electric's critical infrastructure projects without first reviewing the specific details of the proposals, requiring the Company to engage

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25 CLF's initial brief is, at times, difficult to understand. CLF appears to use the term "petition" interchangeably to describe both the Company's request for a base distribution rate increase and request for approval of a PBR plan. Our summary of CLF's arguments, as they pertain to the proposed PBR plan, relies on some assumptions as to which "petition" CLF refers. In future proceedings, a more clearly written brief would facilitate our consideration of the arguments.

with the community before filing for siting approval, and ensuring equitable distribution of burdens and benefits associated with the projects (CLF Brief at 15-16; CLF Letter in Lieu of Reply Brief at 1).

6. TEC and PowerOptions

TEC and PowerOptions argue that the Department should reject the Company's proposed ten-year PBR plan term and instead approve a five-year term that is inclusive of all capital projects (TEC/PowerOptions Brief at 13-14; TEC/PowerOptions Reply Brief at 8). TEC and PowerOptions contend that the historic pace of change currently occurring in the electric industry requires that the Department not relinquish its ability to supervise the Company for a period of ten years (TEC/PowerOptions Brief at 14). Further, TEC and PowerOptions assert that a five-year term is more congruous with the recent Department-approved PBR plans approved for National Grid's electric and gas operating companies in Massachusetts (TEC/PowerOptions Brief at 14).

TEC and PowerOptions also argue that the Company's proposed PBR plan should not include a separate cost recovery factor for the critical infrastructure projects or exogenous cost recovery for Enterprise IT projects, as both categories of projects represent core distribution investments (TEC/PowerOptions Brief at 13; TEC/PowerOptions Reply Brief at 8-9). Further, TEC and PowerOptions contend that the costs associated with the critical infrastructure projects could be evaluated in a base distribution rate proceeding at the end of a five-year PBR plan term, which also would allow for a timely review of mature substation capacity projects (TEC/PowerOptions Reply Brief at 8). Additionally, TEC and

PowerOptions claim that the proposed exogenous cost treatment for Enterprise IT expenses is incongruous with the premises of PBR plans, as, under a PBR plan, the Company is granted annual rate increases to allow for business operations (TEC/PowerOptions Reply Brief at 8). Moreover, TEC and PowerOptions assert that most software is purchased at the service company level, and that the Company's concerns surrounding IT expenses can be mitigated by a five-year PBR plan term (TEC/PowerOptions Reply Brief at 8-9).

TEC and PowerOptions also argue against the proposed roll-in of 2022 capital additions and assert that these additions are outside the scope of review for this proceeding (TEC/PowerOptions Brief at 15). Finally, TEC and PowerOptions support the proposed five-percent inflation cap, including allowing the Company to file a base distribution rate case if earnings fall more than 400 basis points below the ROE authorized in the instant proceeding (TEC/PowerOptions Reply Brief at 9).

7. UMass

UMass argues that the Company's proposed PBR plan should be denied until a better array of metrics is developed (UMass Brief at 47). UMass does not raise any specific arguments on brief about the components of the proposed PBR plan.

8. Company

a. Introduction

The Company asserts that its proposal to continue with a PBR plan is designed to provide funding for needed infrastructure projects and increasing operating expenses between base distribution rate cases (Company Brief at 14). The Company contends that its existing

PBR plan has proven that it is an innovative mechanism that is effective in promoting rigorous cost control, while also enabling investment in emerging technologies that will enhance reliability for residential and business customers and help Massachusetts meet its ambitious clean-energy goals, including the substantial investment in distribution automation, electric vehicle ("EV") infrastructure, and other clean energy capabilities (Company Brief at 14, citing Exh. ES-CAH/DPH-1, at 62).

According to NSTAR Electric, the existing PBR plan challenged the Company to find better, more innovative ways to achieve cost reductions while still providing customers with safe and reliable service, which benefits the overall system, whether in relation to the integration of distributed generation ("DG"), energy storage, or other electrification purposes (Company Brief at 14, citing Exh. ES-CAH/DPH-1, at 62). The Company asserts that during this time, it made total gross investments of over $2 billion in rate base, worked to contain its O&M expenses, did not over earn its authorized ROE, and provided benefits to customers through an overall lower impact to rates than what was forecasted in D.P.U. 17-05 (Company Brief at 19-21, citing Exhs. ES-CAH/DPH-1, at 19-22, 25-27; DPU 25-16). The Company asserts that the PBR construct was also effective at maintaining a level of rate stability and predictability by avoiding relatively larger rate changes that typically accompany a base distribution rate proceeding (Company Brief at 14, citing Exh. ES-CAH/DPH-1, at 62). For these reasons, the Company proposes to continue operating under a PBR Plan with a longer, ten-year term (Company Brief at 14).

NSTAR Electric reiterates its request for Department approval of the Company's initially proposed PBR plan (Company Brief at 15). The Company, however, also asserts that, in the alternative, the Department may allow a ten-year PBR plan with the several revisions proposed during the proceeding (Company Brief at 15, 53-57, citing Exhs. ES-PBR-Rebuttal-1, at 45-46; DPU 63-3). NSTAR Electric contends that its revised PBR plan has several benefits for customers by smoothing the impact of the January 1, 2024, adjustment and maintaining stability over the ten-year term of the PBR plan, while allowing the Company more adequate capital cost recovery (Company Brief at 15, citing RR-AG-7; RR-DPU-43, Tr. 12, at 1260).

b. PBR Plan Components[26]

NSTAR Electric argues that its requested PBR plan term is appropriate because it will create stronger incentives for the Company to maximize opportunities associated with electrification and grid modernization (Company Brief at 45, citing Exh. ES-PBR/PLAN-1, at 16). The Company rejects intervenor arguments that a ten-year PBR plan term is too long (Company Brief at 80-89). The Company argues that the revenue predictability from a ten-year PBR plan will aid its distribution system planning efforts and provide stronger efficiency incentives in doing so (Company Brief at 80). Further, the Company contends that

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[26] The Company summarized the various components of its initial PBR plan proposal and the revised proposal offered during the proceeding (Company Brief at 21-57). In the interest of administrative efficiency, in this section we focus on the components of the proposals challenged by the intervenors and the Company's response to the issues raised by the intervenors.

a ten-year term will allow resources that would have otherwise been devoted to base distribution rate case filings to be put toward meeting future challenges (Company Brief at 80-81). In addition, the Company asserts that a ten-year PBR plan term would provide the flexibility and incentives needed to meet the Commonwealth's clean energy objectives (Company Brief at 82). Moreover, NSTAR Electric contends that approval of a ten-year PBR plan term would not amount to pre-approval of large infrastructure projects or excuse the Company from regulatory review of the prudency of the costs (Company Brief at 85).

NSTAR Electric also expresses confidence in its ability to assume the risk of a ten-year PBR plan term and claims that but for the expiration of its current PBR plan, the Company would not have filed the instant base distribution rate case (Company Brief at 81). Further, the Company argues that because of its unique operating environment and future obligations and requirements, it is inappropriate to allow a five-year PBR plan term simply because that duration was approved for other utilities (Company Brief at 88-89). Finally, the Company submits that it provided a clear outline for its proposed mid-term filing to satisfy the statutory requirements in G.L. c. 164, § 94 (Company Brief at 81).

The Company next argues that contrary to the Attorney General's claims, the TFP study is robust, appropriately designed, and supports the initially proposed X factor of -1.45 percent (Company Brief at 72). The Company rejects the notion that the TFP study should not include costs that are recovered through reconciling mechanisms outside of base distribution rates (Company Brief at 72). The Company asserts that the TFP study is a measure of productivity, not cost recovery, and that the study measures the total cost of providing distribution service (Company Brief at 72-73). Further, the Company argues that the TFP study does not produce overstated results, and ultimately the difference between the TFP study in the instant proceeding and the TFP study performed for D.P.U. 17-05 is only four basis points, which indicates that the model is robust (Company Brief at 73-74). NSTAR Electric also contends that, contrary to Acadia Center's argument, a negative X factor is not indicative of underperformance, but rather is exogenous to the Company's performance, reflects the expected unit cost performance of an average firm in the industry, and indicates increasing capital needs among the industry while output declines or slows in the same period (Company Brief at 90). Additionally, the Company maintains that its current revenue deficiency is not due to imprudent business practices but instead due to unusually high storm costs, increased capital investments, increased enterprise IT costs, and the transfer of vegetation management costs to base distribution rates (Company Brief at 90).

NSTAR Electric argues that its initially proposed 15 basis-point (or 0.15 percent) consumer dividend is supported by Department precedent and two cost benchmarking studies performed by the Company's consultant (Company Brief at 37, citing Exh. ES-PBR/PLAN-1, at 38). The Company contends that the Department has previously found that benchmarking terms of three years apply equally to five- and ten-year PBR plan terms, and, as such, the Department should accept the use of a three-year period for benchmarking (Company Brief at 76). Thus, the Company asserts that it was not necessary to use a longer benchmarking term, as argued by the Attorney General (Company Brief at 76).

The Company also disagrees with the Attorney General's position regarding the proposed ROERA adjustment (Company Brief at 69-71). According to NSTAR Electric, the ROERA adjustment is necessary as the Company will be required to make large capital investments in the next ten years, and changes in capital markets do not presently qualify as exogenous events (Company Brief at 41, citing Exh. ES-CAH/DPH-1, at 76). Further, NSTAR Electric contends that the I-X formula will not appropriately compensate the Company for changes in capital market conditions, and that the risk of not being able to access capital markets is higher over a ten-year period (Company Brief at 42). In addition, the Company argues that it is inordinately affected by changes in capital market conditions as electric distribution is a capital-intensive industry, and financial risks are exacerbated by current inflation rates and the ensuing impact on debt and equity rates, which are not reflected in the TFP study (Company Brief at 42, 71).

Regarding the proposed exogenous cost provision, the Company disagrees with the Attorney General's contention that Enterprise IT costs should not be eligible for recovery (Company Brief at 78). The Company argues that it is becoming more cost-effective to utilize cloud computing, which results in more IT costs being incurred as expense rather than capital (Company Brief at 39, citing Exh. ES-CAH/DPH-1, at 86). Thus, the Company contends that it is necessary to treat these costs as exogenous under the PBR plan (Company Brief at 39). The Company asserts that if it does not incur these costs, as the Attorney General suggests, then there will be nothing to recover (Company Brief at 78). Further, the Company contends that it will have to demonstrate that any Enterprise IT costs sought for exogenous recovery are incremental to amounts provided in base distribution rates (Company Brief at 78).

Next, NSTAR Electric argues that to make the proposed ten-year PBR plan term feasible, the Company should be allowed to roll-in 2021 and 2022 capital investments (Company Brief at 53, citing Exh. ES-CAH/DPH-1, at 74-75). Further, the Company contends that its proposal is consistent with the Department's approval of a ten-year PBR plan term for NSTAR Gas (Company Brief at 87, citing D.P.U. 19-120, at 72). Finally, NSTAR Electric claims that TEC and PowerOptions have not provided any basis for deviating from this precedent or any evidence that the requested capital roll-ins would not be necessary for the Company's PBR plan (Company Brief at 87, citing TEC/PowerOptions Brief at 15). Based on these considerations, the Company asserts that the Department should allow the roll-in of 2022 capital additions if the ten-year PBR plan term is approved (Company Brief at 87).

The Company agrees with many of the Attorney General's proposed tariff changes, and contends they represent suggestions to directly incorporate definitions that are contained in other referenced tariffs (Company Brief at 79). The Company, however, does take issue with several of the Attorney General's recommendations (Company Brief at 79).

Finally, the Company rejects the Attorney General's recommended "all-in capital tracker" (Company Brief at 59). NSTAR Electric argues that, due to the magnitude of the prospective filing, an all-in capital tracker would be more administratively burdensome than the proposed PBR plan for the Company, Department, and relevant stakeholders (Company

Brief at 59-60, citing Exh. DPU 25-13). Further, the Company contends that an all-in capital tracker would create poor incentives by encouraging capital expenditure, and therefore, such a tracker is not compatible with the Department's efficiency goals (Company Brief at 61). In addition, the Company claims that an all-in capital tracker would lead to increased regulatory costs as more frequent base distribution rate cases would be needed to roll the additions into base distribution rates (Company Brief at 61). According to the Company, its K-bar proposal is a better option, as it does not result in dollar-for-dollar recovery and the PBR adjustments are automatic, leaving intact both cost control incentives and administrative efficiencies (Company Brief at 56-57, 60-61).

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 initially proposed PBR plan and the proposed revised plan, and we determine whether allowing a PBR plan 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 and gas distribution companies.[27] 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 electric and gas distribution companies 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, 375 Mass. 1, 19. 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).

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

In addition, G.L. c. 164, § 76, grants the Department broad supervision over electric and gas distribution companies. 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. D.P.U. 07-50-B at 26-27. 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 are many variations and adjustments in the specific application of this model to individual utilities as circumstances differed across companies and across time. D.P.U. 07-50, at 8. Over the years, electric and gas distribution companies subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See, e.g., D.P.U. 19-120, at 58; 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/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 an alternative 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 electric and gas distribution companies. 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 the propriety of rates under G.L. c. 164, § 94, the Department must find that the 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 a number of 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 of 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

There is a fundamental evolution taking place in the way electricity is produced and consumed in Massachusetts. This evolution has been driven, in large part, by a number of legislative and administration policy initiatives designed to address climate change and to foster a clean energy economy through the promotion of energy efficiency, demand response, and DG, and the procurement of long-term contracts for renewable energy. See, e.g., 2022 Clean Energy Act; An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act"); The Massachusetts 2050 Decarbonization Roadmap[28]; An Act Relative To Green Communities, St. 2008, c. 169 ("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). To varying degrees, this evolution is changing the operating environment for EDCs in Massachusetts.

As described above, the Company proposes to continue operating under a PBR plan for the next ten years (Exhs. ES-CAH/DPH-1, at 13, 63, 93; ES-PBR/PLAN-1, at 13; ES-PBR-Rebuttal-1, at 45). In addition to the arguments set forth above in Section IV.C.8, NSTAR Electric states that its operating dynamics will continue to evolve bringing even greater technological complexity, larger investment requirements, and a persistent need to

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28 The Massachusetts 2050 Decarbonization Roadmap defines eight decarbonization pathways, and the "All Options" pathway is the benchmark compliant decarbonization 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).

find and develop skilled personnel to manage the Company and meet the expectations of customers on a day-to-day basis (Exh. ES-CAH/DPH-1, at 33). In particular, NSTAR Electric states that its fundamental challenge is a pressing need to complete system upgrades and improvements to meet growing customer expectations of reliability and resiliency; increase system demands in anticipation of electrification; and integrate DG, all in the face of stagnant sales volumes (Exh. ES-PBR-Rebuttal-1, at 5). Further, the Company notes that it is planning for the future with particular focus on building capabilities to meet future service requirements in an electrified environment (Exhs. ES-CAH/DPH-1, at 33; ES-ENG-1, at 10-21; ES-PBR-Rebuttal-1, at 5). According to NSTAR Electric, PBR is a critical factor in the Company's operating environment because it provides the Company with the latitude to focus on operations and to meet expectations, while providing the critical resources necessary to "make ends meet" (Exh. ES-CAH/DPH-1, at 33-34). In addition, the Company submits that PBR creates broad-based incentives for cost control because it applies across the entire utility operation and supports both capital investment and O&M costs (Exh. ES-PBR-Rebuttal-1, at 12). Further, NSTAR Electric expects that without a PBR plan, the Company likely would file up to four base distribution rate cases through the end of 2031 to keep up with the substantial capital outlay expected over a ten-year period (Exh. ES-PBR-Rebuttal-1, at 48).

As discussed above in Section IV.C, several intervenors argue against the Company's PBR plan proposals as not in the public interest, not tied to achievement of any specific, measurable results, or otherwise not appropriate for approval. Further, several of the intervenors recommend changes to the Company's proposals, should the Department approve a PBR plan.

The Department finds that the Company has demonstrated that continuing its PBR plan is an appropriate alternative to traditional cost of service/rate of return ratemaking. During the current PBR term, approved in D.P.U. 17-05, the Company made over $2 billion in capital investments in new business and peak load growth, basic business requirements, and replacement of aging infrastructure (Exh. ES-CAH/DPH-1, at 19-25). In particular, the Company installed, expanded, or upgraded its infrastructure to accommodate electric demand growth and installed new or replaced old distribution equipment in an effort to reduce the number of outages experienced by customers. (Exh. ES-CAH/DPH-1, at 20). Further, during the current PBR term, the Company instituted a variety of cost containment initiatives, including implementation of robotic process automation; using data analytics to streamline and automate reliability reporting and other work processes; fleet standardization; contract renegotiations; and leveraging of supply chain partnerships and use of contractors of choice for engineering work (Exh. ES-CAH/DPH-1, at 18-19, 25-26). In addition, we find that NSTAR Electric has demonstrated that the current PBR plan has been effective in maintaining rate stability, delivery price predictability and avoiding relatively larger rate changes (Exhs. ES-CAH/DPH-1, at 18-19, 62; DPU 25-16).

The Department finds that allowing NSTAR Electric to continue to operate under a PBR plan will provide the Company more flexibility to address an evolving operating environment, such as changes in energy and climate policy; emerging technologies;

challenges in hiring, training, and retaining skilled personnel; replacing, upgrading, and maintaining aging infrastructure; increasing frequency and intensity of storms; and higher customer expectations (Exhs. ES-CAH/DPH-1, at 31-61; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32). Further, as part of the PBR plan, the Company has committed to refraining from filing rate schedules to put new base distribution rates into effect during the PBR plan term (Exh. ES-CAH/DPH-1, at 68 n.10, 86, 92). The Department accepts that this stay-out provision will result in diminished administrative burden and in efficiencies (Exh. ES-CAH/DPH-1, at 59).

In addition, the Department finds that, in this instance, a PBR plan is 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, as discussed below, the Department adopts a K-bar approach to capital spending within the approved PBR plan. The flexibility and revenue predictability provided by the K-bar approach will allow the Company to address a variety of future expenses without additional cost recovery filings. 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. DPU 35-5; RR-DPU-12, at 3). In contrast, 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.

Finally, as discussed in Section V.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 not persuaded by the Attorney General's argument that the Company's proposed PBR plan is overly focused on cost recovery.

Below, the Department addresses the specific components of the PBR plan and whether the PBR mechanism appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates.

5. PBR Plan Components

a. PBR Plan Term

The Company initially proposed a ten-year PBR term with a mid-term filing of rate schedules at the five-year mark (Exhs. ES-CAH/DPH-1, at 13, 93; ES-PBR/PLAN-1, at 13). In its rebuttal testimony, the Company revised certain components of its proposed PBR plan. In offering some revisions to its PBR plan during the course of the proceeding, the Company, however, did not revise the term of PBR plan and proposed to maintain the ten-year term (Exh. ES-PBR-Rebuttal-1, at 45). The ten-year PBR term would commence on January 1, 2023, and expire on December 31, 2032, during which there would be nine annual PBR mechanism adjustments, taking effect each January 1, beginning in 2024 (Exh. ES-CAH/DPH-1, at 64-65, 93). In conjunction with the PBR term, NSTAR Electric proposed a stay-out provision whereby the Company may file a base distribution rate case during the PBR term that would result in new base distribution rates going into effect no earlier than January 1, 2033 (Exh. ES-CAH/DPH-1, at 68 n.10, 86, 92).

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. 96-50 (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. 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). The Department finds that the circumstances presented in the instant case do not support a PBR plan term of ten years. Instead, the Department approves a PBR plan term of five years with the possibility of a five-year extension, as discussed further below.

As noted above, the Company intends to undertake substantial capital investments over the next five- to ten-year period, such as the critical infrastructure projects and other investments necessary to comply with legislative and administration policy initiatives designed to address climate change and to foster a clean energy economy (Exhs. ES-CAH/DPH-1, at 77-82; ES-PBR-Rebuttal-1, at 39-40; ES-ENG-1, at 7-8; ES-ENG-3). Due to these and other anticipated expenditures, the Department is hesitant to allow annual formulaic revenue adjustments over a longer term that likely will not align with capital investment requirements.

The Department reaffirms that a longer PBR term generally coincides with stronger economic incentives, a longer strategic planning horizon, and additional time to accrue administrative efficiencies, supporting the policy that a PBR term of up to ten years, under the right circumstances, is preferrable. D.P.U. 20-120, at 72. Our finding here of a five-year PBR term is grounded in the specific circumstances presented in this case. Further, 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. 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. 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.

In recognition of the Company’s forecasted spending, and given our preference for longer term PBR plans, the Department finds it reasonable and appropriate to allow the Company, prior to the expiration of the five-year PBR plan term, to file a request to continue the PBR plan term for another five years. This request must be filed with the Department no earlier than nine months and no later than six months prior to the termination of the initial PBR plan term. In the filing, the Company must demonstrate that it is in the public interest to continue the current PBR mechanism for another five years. NSTAR Electric must include testimony and supporting revenue requirement schedules that show the anticipated revenue deficiency would be if the Company were to file a base distribution rate case. The Company's filing also shall include a performance metrics proposal, as discussed in Section V.D.3 below. The Department will investigate the request and provide the Attorney General and other interested stakeholders an opportunity to comment on the filing. Balancing the best interests of ratepayers with the financial integrity of the Company, if the Department determines that continuing the PBR term is in the public best interest, the Company may continue the PBR plan for an additional five-year period, with no changes to the base distribution rates approved in the instant proceeding. If the Department determines that continuing the PBR plan term is not in the public interest, the stay-out provision shall be extended approximately one year, and the PBR plan approved in the instant case shall remain in place for one additional year to allow the Company sufficient time to prepare a base distribution rate filing.[29]

b. Productivity Offset

As noted above, the Company initially proposed an X factor of -1.45 percent (Exh. ES-PBR/TFP-1, at 24). In its rebuttal testimony, the Company proposed to reduce the

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[29] The Department may initiate procedural discussions with the Company and relevant stakeholders regarding the timing of the subsequent base distribution rate case filing.

X factor to zero, as recommended by the Attorney General (Exh. ES-PBR-Rebuttal-1, at 44-45, citing Exhs. AG-DED-PBR-1, at 3, 58; AG-DPL-1, at 12). The Department finds that the Company's revised proposed X factor of zero is appropriate, particularly when considering the other changes and modifications to the PBR plan approved herein. As such, we approve an X factor of zero.

c. Inflation Index and Floor

As noted above, the Company initially proposed to calculate the price inflation index based on the GDP-PI, with an inflation "floor" equivalent to the X factor of -1.45 percent so that a negative PBR adjustment would not occur (Exh. ES-CAH/DPH-1, at 68). In its rebuttal testimony, NSTAR Electric proposed to cap the inflation index at five percent, and the Company stated that it would "make sense" to have the opportunity file a base distribution rate case if reported earnings fall more than 400 basis points below the ROE authorized in the instant proceeding (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 35-1).

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 whose TFP growth 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 approves its use.

As described above, the Company has proposed to include an inflation cap of five percent in the revenue cap formula, meaning that if inflation rises above five percent, the Company will set the inflation component of the PBR formula at five percent (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 35-1). The remaining parties do not oppose the proposed inflation index cap (Attorney General Brief at 65; DOER Brief at 17-18; TEC/PowerOptions Reply Brief at 9). Accordingly, the Department approves the Company's proposed inflation index cap of five percent. The Department, however, disallows including a provision in the Company's proposed PBR plan that would allow the Company the opportunity to file a base distribution rate case if reported earnings fall more than 400 basis points below the ROE authorized in this proceeding. The Department is not persuaded that, absent other extenuating circumstances, such a situation warrants terminating the PBR plan and the associated stay-out commitment.

Finally, the Company proposed an inflation floor equivalent to the X factor of -1.45 percent so that a negative PBR adjustment would not occur (Exh. ES-CAH/DPH-1, at 68). In support of this proposal, the Company stated that its cost of service would never decline, even in a deflationary period (Exh. ES-CAH/DPH-1, at 68). While the Company has not substantiated this claim, we, nevertheless, find that an inflation floor of zero, to correspond with the approved X factor, is a reasonable component of the PBR mechanism, particularly when coupled with the inflation index cap approved above. Accordingly, the Department approves an inflation floor of zero for the Company.

d. Consumer Dividend

The consumer dividend is intended to reflect expected future gains in 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. ES-CAH/DPH-1, at 73; ES-PBR/PLAN-1, at 37). The Department has found that a consumer dividend represents an explicit, tangible ratepayer benefit. D.P.U. 18-150, at 60-61; D.P.U. 17-05, at 395.

As discussed above, the Company initially proposed to include a consumer dividend of 15 basis points, or 0.15 percent, when inflation, as calculated in the proposed PBR formula, exceeds two percent (Exhs. ES-CAH/DPH-1, at 72; ES-PBR/PLAN-1, at 38). In its rebuttal testimony, the Company proposed to raise the consumer dividend to 25 basis points, or 0.25 percent, when inflation exceeds two percent (Exh. ES-PBR-Rebuttal-1, at 45). The Department finds that the Company's revised proposed consumer dividend is appropriate, particularly when considering the other changes and modifications to the PBR plan approved herein. As such, we approve the Company's revised consumer dividend of 0.25 percent when inflation exceeds two percent.

e. Post-Test-Year Capital Additions

NSTAR Electric asserts that over the next several years the Company anticipates making significant capital additions to improve the resiliency of the distribution system and to ensure safe and reliable service as the Commonwealth pursues its electrification objectives (Exhs. ES-CAH/DPH-1, at 31-61; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32). To address its prospective capital investments, the Company initially proposed to include post-test-year capital additions (i.e., 2021 and 2022 capital additions) in base distribution rates at two different intervals during the term of the proposed PBR plan and proposed to recover future critical infrastructure projects investments through the PBR mechanism (Exh. ES-CAH/DPH-1, at 74-75). In its rebuttal testimony, the Company proposed to eliminate the roll-in of the 2022 calendar-year capital additions from the first annual PBR plan filing and to eliminate its proposed rate treatment of future critical infrastructure projects (Exh. ES-PBR-Rebuttal-1, at 45). Instead, the Company proposed, as part of the revised PBR formula, a K-bar adjustment that would allow additional revenues to be collected through the PBR adjustments, beginning January 1, 2024, to provide additional funding for capital investments (Exhs. ES-PBR-Rebuttal-1, at 45; DPU 63-3 & Atts.; RR-DPU-12 & Atts.).

The Department recognizes that, during the PBR term, NSTAR Electric will need flexibility to address the evolving energy and climate policies governing EDCs, as well as to maintain aging infrastructure and enhance resiliency to address the impacts of climate change (Exhs. ES-CAH/DPH-1, at 31-61; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32). 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 anticipates that the Company may identify several capital projects to achieve these objectives during the development of its electric sector modernization plans 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 (November 30, 2022). 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 aligns more closely with the Company's objectives and needs than allowing a roll-in of the 2022 capital investments and the implementation of a separate recovery factor for critical infrastructure projects; therefore, and subject to the modifications below, the Department approves the incorporation of the K-bar in the Company's PBR mechanism.

The Department has reviewed both a fixed historical average and annual rolling-average K-bar approach (RR-DPU-12 & Atts.; RR-DPU-43 & Atts.; RR-DPU-44, Att.). For the reasons discussed below, 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 would provide the Company with a predictable level of funding each year of the PBR term regardless of the Company's actual capital investments. While the Department fully expects that NSTAR Electric will pursue system improvements annually, we acknowledge that large-scale capital projects may be delayed for reasons beyond the Company's control, including difficulty in obtaining permitting and/or engineering studies (Exh. ES-CAH/DPH-1, at 81-82). 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. ES-CAH/DPH-1, at 31-61, 78-82; ES-PBR/PLAN-1, at 15-16, 31-34; ES-PBR-Rebuttal-1, at 23-32; RR-DPU-43, at 6-7).

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 (see RR-DPU-43, Att. (g); RR-DPU-44). Accordingly, the Department will limit the amount of capital improvements that may be automatically included in the annual K-bar adjustment. Specifically, the Department allows the Company an annual capital spending constraint of up to ten percent from the annual capital spending forecasted in this proceeding ("Forecasted Budget") (Exh. AG 1-18, Att. (Supp.); RR-DPU-43, Att. (d)).[30] As noted above, we recognize the challenges in accurately forecasting capital spending, as well as the potential impacts on future capital spending from recent and anticipated changes in energy and climate policy. As such, the Department finds it appropriate to allow a modest amount of flexibility from the Company's Forecasted Budget in setting the expenditure restraint.

Beginning with the annual PBR adjustment effective January 1, 2024, the Company's actual capital costs[31] for the calendar year prior to the year of the annual PBR plan filing, will be allowed for inclusion in the calculation of the K-bar average capital cost to the extent

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[30] The Forecasted Budget shall exclude capital projects that are eligible for recovery though rate mechanisms outside of base distribution rates (i.e., solar investments, meter-related capital as discussed in Section XV.C.2 below, and grid modernization investments).

[31] Actual capital costs shall exclude capital projects that are eligible for recovery though rate mechanisms outside of base distribution rates (i.e., solar investments, meter-related capital as discussed in Section XV.C.2 below, and grid modernization investments).

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 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, then the K-bar allowance shall be capped at the ten-percent variance[32] from the Forecasted Budget, by excluding the variance from the K-bar calculation (Exh. AG 1-18, Att. (Supp.); RR-DPU-43, Att. (d)). 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 to the Company, is administratively efficient, and will avoid the burdensome review of an annual capital tracker mechanism.[33]

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32 To determine the capital projects that exceed the ten-percent cap compared to the Forecasted Budget, the Company shall sum the actual capital costs from the prior year from least expensive to most expensive, for informational purposes. Based on this ranking, the Department may review the reasons for the budget overrun, and, if appropriate after notice, investigate prudence.

33 The Department notes that the approved K-bar relies on accurate forecasted capital spending by the Company. In this regard, the Department places NSTAR Electric on notice that we may investigate the Company's capital spending if the Department concludes that the Company inappropriately over-estimated its Forecasted Budget and is lagging too far behind on investing into the distribution system. Further, the Department may investigate the prudency of any capital investment project included in the K-bar at any time and make any adjustment necessary if Company expenditures are determined to be imprudent.

In its 2023 PBR adjustment filing, the Company shall calculate the K-bar adjustment for effect January 1, 2024 using the five-year average of actual plant additions placed in service from 2018 through 2022[34] with the 2022 and 2023 bridge years both calculated using the five-year average of actual plant additions placed in service from 2017 through 2021 and carried forward to January 1, 2024, using the I-X formula in the PBR mechanism approved in the instant proceeding (RR-DPU-43, at 5-7 & Att. (d) at 4, line 25; at 7, lines 20, 28). The K-bar adjustment for effect January 1, 2025, will calculate the K-bar using the five-year average of plant additions placed in service from 2019 through 2023 (RR-DPU-43, at 5). The PBR adjustment for effect January 1, 2026, will calculate the K-bar using the five-year average of plant additions placed in service from 2020 through 2024 (RR-DPU-43, at 5). The five-year average will be updated in the same manner for each subsequent year that the K-bar remains in effect (RR-DPU-43, at 6-7). For the K-bar calculation, the deprecation 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 Schedule 5 below.

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34 Given that plant additions placed in service in 2018 may be considered under the PBR plan approved in D.P.U. 17-05, we find it appropriate, and consistent with the Alberta approach, to use a five-year period that begins with 2018 and not with 2017 to derive the initial level of average spending (RR-DPU-12).

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 NSTAR 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 the Company no longer will need to request to roll-in 2022 capital additions through the PBR mechanism (Exh. ES-PBR-Rebuttal-1, at 45; RR-DPU-12, at 3).

The Department finds 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. With the approval of the K-bar mechanism, the Department expects a reasonable level of stability in NSTAR Electric's 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, should the Company choose to file a new base distribution rate case upon expiration of the PBR plan term (see Section IV.D.5.a above). 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. Finally, as part of its annual PBR filings, the Company shall file a forecast of its capital investment projects planned to go into service in the subsequent year, and the associated costs of those projects, for informational purposes. In addition, once available, the Company shall file, for informational purposes, its actual capital investment projects for the year of its annual PBR filing. For example, in its 2023 annual PBR filing, the Company shall file its forecasted 2024 planned capital investment projects. Then, in its 2024 annual PBR docket, the Company shall make an informational filing of its actual 2024 capital investment projects in the first quarter of 2025. These informational filings will assist the Department and stakeholders to monitor NSTAR Electric's 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.

f. ROERA Factor

As discussed above, the Company initially proposed to include in the PBR plan an ROERA mechanism to recover costs arising from changes in the capital markets during the proposed ten-year PBR term (Exhs. ES-CAH/DPH-1, at 76; ES-PBR/PLAN-1, at 8). The ROERA would be triggered, and a rate adjustment would take place, if the yield on ten-year Treasury bonds reaches 200 basis points above or below the yield in effect at the start of the PBR plan (Exh. ES-CAH/DPH-1, at 76-77). Given that the Department has approved a five-year PBR term, and in light of the other components of the PBR plan approved herein, we find that it is inappropriate to approve an ROERA adjustment.[35] We note that changes in the required cost of capital would be recovered, to a considerable extent, through the operation of the inflation index factor and the appropriate shifts in the Company's capital structure. Further, the Department also finds that the Company's ESM provides an additional layer of insulation from the kind of financial risk that the ROERA is designed to mitigate. Based on these considerations, the Department is not persuaded that the proposed ROERA is a necessary component to successful operation of the PBR plan. Accordingly, the Department rejects the Company's proposed ROERA.

g. Cost Treatment of Critical Infrastructure Projects

In its initial filing, NSTAR Electric proposed to recover costs associated with its critical infrastructure projects through a separate recovery factor at three intervals during the proposed ten-year PBR plan term (Exh. ES-CAH/DPH-1, at 82). In its rebuttal testimony, the Company proposed to eliminate the specific cost recovery factor associated with the critical infrastructure projects and instead would recover the costs associated with these projects through the K-bar adjustment (Exh. ES-PBR-Rebuttal-1, at 45). As discussed above, the Department has approved a K-bar adjustment as part of the Company's PBR plan, which would include recovery of costs associated with these projects. As such, a separate cost recovery factor associated with the critical infrastructure projects is unnecessary. Accordingly, the Company shall remove this factor from the PBR mechanism.

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35 As noted in n.18 above, it appears that the Company acknowledges that the ROERA would not apply to a five-year PBR plan term.

h. ESM

The Company initially proposed an 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. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE is between 150 and 200 basis points below the authorized ROE, sharing with customers would be triggered on a 50/50 percent basis (50 percent to customers and 50 percent to the Company) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). If the computed distribution ROE exceeds 200 basis points below the authorized ROE, sharing with customers would be triggered on a 75/25 percent basis (75 percent to customers and 25 percent to the Company) (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). The Company proposed 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 (Exh. ES-CAH/DPH-1, at 91). In its rebuttal testimony, the Company did not propose to revise or remove the proposed ESM from the revised ten-year PBR plan (Exh. ES-PBR-Rebuttal-1, at 45).

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 an 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 adopted in this case.

The Company developed the proposed ESM in alignment with Department precedent for a ten-year PBR term (Exhs. ES-CAH/DPH-1, at 90; ES-PBR/PLAN-1, at 12). 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. 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. Moreover, as noted above, the Company proposed that, if a five-year PBR term is approved, the ESM would be asymmetrical with upside sharing for customers, but no downside adjustment for the Company (Exh. DPU 1-1).

In this Order, the Department has approved a PBR plan term of five years for NSTAR Electric. 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.

i. Exogenous Cost Factor

As noted above, NSTAR Electric initially proposed to include in the PBR adjustment formula an exogenous cost provision (or "Z factor"), in particular to address incremental property taxes arising from a municipality's change in valuation method for assessing utility property and for expenses incurred for certain Enterprise IT investments (Exhs. ES-CAH/DPH-1, at 83-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). 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 distribution industry as opposed to the general economy; and (4) meet a threshold of "significance" for qualification (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Company proposed the significance threshold for exogenous costs to be set at $4 million in 2023 and adjusted annually by the change in GDP-PI, except for exogenous costs associated with Enterprise IT expenses, for which the initial threshold would be set at $6 million (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). In its rebuttal testimony, the Company did not propose any revisions to the exogenous cost provision.

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, because the company is 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 (Exhs. ES-CAH/DPH-1, at 83-84; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch.1, at 455). Accordingly, the Department finds that the Company's proposed definition of exogenous costs in this instance is appropriate.

In D.P.U. 96-50 (Phase I) at 292-293, the Department found that to avoid a costly regulatory process over minimal dollars, exogenous cost recovery must be subject to a significance threshold that is noncumulative (i.e., exogenous costs cannot be lumped together into a single total for purposes of determining whether the threshold has been met). See also D.T.E. 01-56, at 22-23; Boston Edison Company, D.T.E. 99-19, at 26 (1999). The Department notes that recently, in very limited circumstances, we have considered the total exogenous costs that occurred in a single year arising out of a change in regulatory guidance that induced a significant number of municipalities to change the method of valuing property for tax purposes. Eversource Gas Company of Massachusetts, D.P.U. 22-122, at 8-11 (October 31, 2022); NSTAR Gas Company, D.P.U. 22-121, at 12 (October 31, 2022);

NSTAR Gas Company, D.P.U. 21-107-A at 19-20 (October 28, 2022). The Department did not intend for these decisions to represent a wholesale shift in our standard that exogenous cost recovery must be subject to a significance threshold that is noncumulative. Therefore, the Department finds that NSTAR Electric must revise its proposed tariff to specify that the significance threshold is noncumulative, subject to the very limited circumstances noted above.[36]

As noted above, the Company proposed an exogenous cost significance threshold of $4 million for calendar year 2023, subject to annual adjustments thereafter based on changes in GDP-PI (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). 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. 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 $4 million is a reasonable exogenous cost significance threshold for the Company, which has total operating revenues of $3,136,349,876, and is implementing a multi-year PBR plan

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36 For example, the tariff could read: The significance threshold for Exogenous Costs is set at $4 million for each individual event in calendar year 2023. The significance threshold must be noncumulative, subject to a finding that the exogenous costs arise from the same type of exogenous event addressed by the Department in NSTAR Gas Company, D.P.U. 21-107-A at 17-20 (October 28, 2022) and interpreted in subsequent decisions.

with the overall design approved herein (Exhs. ES-CAH/DPH-1, at 84-85; ES-REVREQ-2, Sch. 6 (Rev. 4)).[37]

In addition, the Company has proposed 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. ES-CAH/DPH-1, at 85). 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. 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; Eastern Enterprises/Colonial Gas Company, D.P.U. 98-128, at 56-57 (1999). Accordingly, we set the Company's threshold for exogenous cost recovery at $4 million for each individual event in the first PBR year, ending December 31, 2023, subject to annual adjustments thereafter based on changes in GDP-PI as used in the PBR mechanism. Based on the foregoing analysis, the Department approves the Company's proposed exogenous cost factor, subject to our finding below as to Enterprise IT expenses.

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. D.T.E. 99-19, at 25; 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

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[37] Multiplying NSTAR Electric's total operating revenue of $3,136,349,876 by the factor of 0.001253 equals $3,929,846.

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.

As noted above, the Company proposes to utilize the exogenous cost provision to recover the costs of certain Enterprise IT expenses, for which the initial threshold would be set at $6 million (Exhs. ES-CAH/DPH-1, at 84-86; ES-PBR/PLAN-1, at 7; ES-RDC-6, Sch. 1, at 455). The Attorney General argues that NSTAR Electric's proposed inclusion of certain Enterprise IT expenses in the exogenous cost factor should be rejected because ESC will incur these costs, and that the Company already is compensated for IT costs through base distribution rates and the annual PBR adjustments (Attorney General Brief at 59-60). Further, the Attorney General asserts that the Company does not recognize or net out any economic benefits that accrue as a result of the implementation of the new IT systems (Attorney General Brief at 60). TEC and PowerOptions also argue that these expenses should be excluded from the exogenous cost provision (TEC/PowerOptions Brief at 13; TEC/PowerOptions Reply Brief at 8-9).

The Company's justification for including Enterprise IT expenses in the exogenous cost provision is tied to the proposed ten-year PBR plan term (Exh. ES-CAH/DPH-1, at 88-89). The Company acknowledges that a level of Enterprise IT expense will be collected through base distribution rates and that will be subject to the annual PBR adjustment (Exh. ES-CAH/DPH-1, at 88). NSTAR Electric states, however, that over the proposed ten-year PBR term, the Company will be adding new systems and other systems will become fully amortized and drop off (Exh. ES-CAH/DPH-1, at 88). According to NSTAR Electric, it will be difficult for the Company to assess whether the amount of Enterprise IT expense that will be locked into base distribution rates will keep pace with actual costs and, therefore, the exogenous cost relief may be necessary (Exh. ES-CAH/DPH-1, at 89). Given that the Department has approved a five-year PBR plan term, we find that an exogenous cost provision applicable to Enterprise IT costs is unnecessary. Moreover, we find that the nature of the costs sought for exogenous cost treatment are inconsistent with the definition of exogenous costs approved herein. Thus, we deny this aspect of the Company's proposal. In its compliance filing, NSTAR Electric shall revise its PBR tariff accordingly.

j. PBR Adjusted Revenues

As noted above, the Attorney General argues that Solar Expansion Program investments should not be included in the base distribution rate revenue requirement portion of the PBR rate formula (Attorney General Brief at 117, citing Exh. AG-TN-1, at 9-10). In Section XIV.B.4 below, the Department approves the transfer of the unrecovered balance of these investments into base distribution rates. Here, the Department finds that it is appropriate to remove these costs from the PBR mechanism adjustment calculation and maintain the revenues associated with these solar facilities at the level approved in this proceeding until the Company's next base distribution rate case. The Solar Expansion

Program costs represent power generation costs, rather than distribution costs. Further, the costs associated with the Solar Expansion Program fall outside the Company's regular operations of safely and reliably delivering electricity to customers. Accordingly, the Company is not obligated to replace these assets when they retire, but it could continue to collect a revenue target that increases annually by the PBR mechanism. The Department has found it suitable to modify PBR plans or simplified incentive plans to exclude adjustments for certain types of costs. D.P.U. 18-150, at 73 (excluding solar facility costs from PBR adjustment); NSTAR Electric Company, D.P.U. 18-101 (2018), Exhs. NSTAR-DPH at 18; NSTAR-DPH-1, at 1 (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/post-retirement benefits other than pension ("PBOP") costs). The Department, therefore, directs the Company to revise the definition of PBR revenue to exclude the costs of the Solar Expansion Program approved in this proceeding, as well as other solar facilities that were approved in previous proceedings (see Section XIV.B.4 below).

6. PBR Tariff Provisions

As noted above, the Attorney General argues that, should the Department allow a PBR plan for NSTAR Electric, numerous provisions in the Company's proposed tariff should be revised to provide appropriate definitional and clarifying language (Attorney General Brief at 60-61). The Attorney General identifies 16 proposed revisions to the tariff (Attorney General Brief at 60-61).

Eight of the proposed revisions are no longer necessary given the Department's findings above regarding the PBR plan components. They are identified in the Attorney General's initial brief as proposed revisions (2), (5), (6), (7), (8), (9), (14) and (15). The Department approves five of the remaining proposed revisions that were agreed-upon by the Company. They are identified in the Attorney General's brief as proposed revisions (1), (4), (10), (11) and (16). The Company is directed to revise these provisions accordingly in the compliance filing.

Three contested proposed revisions remain. In proposed revision (3), the Attorney General argues that the definition of "Distribution Common Equity" in the proposed PBR plan tariff should reflect the removal of common equity associated with any: (1) unamortized acquisition premium and/or goodwill; and (2) non-distribution service investments and services (Attorney General Brief at 60-61). The Company disagrees with the Attorney General, "based on the Department's prior approvals, and method for calculating an ROE for earnings sharing purposes, as approved in D.P.U. 14-150, D.P.U. 17-05, and D.P.U. 19-120" (Company Brief at 79). The Company also asserts that its methodology in reporting the distribution-only ROE remains unchanged from what was approved in D.P.U. 17-05 as part of the existing PBR plan (Company Brief at 79). The Department finds that the definition of "Distribution Common Equity" in NSTAR Electric's proposed PBR plan tariff (Exh. ES-RDC-6, Sch. 2, at 235) is substantially similar to the language in the Company's current PBR plan tariff, M.D.P.U. No. 59E, § 1.04 (8). Further, the minor differences in the language between the two versions do not and should not be interpreted to impact the method used to derive distribution common equity for purposes of the PBR plan. The Attorney General does not provide any additional support for her argument, and we see no compelling reason to revise the definition as proposed. As such, we decline to adopt the Attorney General's recommendation.

In proposed revision (12), the Attorney General argues that the definition of "Transmission Net Income" does not account for any changes in the net income that might arise from refunds to customers as a result of any contested charges at Federal Energy Regulatory Commission ("FERC") (Attorney General Brief at 61). The Company argues that no revisions are necessary because the "calculation of ROE remains unchanged from D.P.U. 17-05" (Company Brief at 79). The definition of Transmission Net Income" in the proposed PBR plan tariff (Exh. ES-RCD-6, Sch. 2, at 237) is unchanged from the definition approved in the Company's current PBR plan tariff, M.D.P.U. No. 59E, § 1.04 (20). Nevertheless, we find that it is reasonable for the Company to include clarifying language that the transmission net income will account for any refunds to customers resulting from favorable FERC decisions as to contested charges. We direct the Company to revise the language accordingly in the compliance filing.

Finally, in proposed revision (13), the Attorney General argues that the X factor should be defined as "the sum of the Productivity Trend differential and the Input Price Trend," without the addition of "negative 1.45 percent ..." (Attorney General Brief at 61). The Company argues that the language in this definition will depend on the X factor approved in this proceeding (Company Brief at 79-80). In Section IV.D.5.b above, the

Department approved an X factor of zero. The Attorney General does not provide any additional support for her argument, and we find that the X factor should be expressly stated in this section of the tariff. Accordingly, we direct the Company to revise the relevant tariff language in the compliance filing to set the X factor at zero.

7. Conclusion

In the sections above, the Department has reviewed the Company's PBR plan proposals and has found that, as approved, the PBR plan is more likely than current regulation to advance the Department's goals of safe, secure, reliable, equitable, and least-cost service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. G.L. c. 25, § 1A. In addition, the Department has found that the PBR plan, 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 has found that the PBR plan, as approved, better satisfies our public policy goals and statutory obligations, including promotion of a safe and reliable electric distribution system, and of the Commonwealth's clean energy goals and mandates.[38]

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[38] The Department notes that many cost recovery mechanisms need to be considered to ensure that EDCs comply with policy goals and statutory obligations effective since the development of revenue decoupling. See D.P.U. 07-50-A at 10. With the discontinuance of full revenue decoupling, EDCs no longer would have a disincentive to pursue strategic electrification because they now would be able to retain the sales from increased load, which may also obviate the need for some capital trackers. Nonetheless, we remind NSTAR Electric that with an approved PBR plan with a

With the modifications required herein, the Department finds that the PBR plan appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates pursuant to G.L. c. 164 § 94. Accordingly, the Department approves a PBR plan for the Company, subject to the modifications above. The Company, in its compliance filing, shall submit a revised PBR plan tariff consistent with the findings in this Order.

Further, the Company shall submit an annual PBR adjustment filing, including all information and supporting schedules necessary for the Department to review the proposed PBR adjustment 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. The Company is directed to submit its annual PBR adjustment filing on or before September 15 of each year, commencing in 2023 and continuing for the five-year term of the PBR. Consistent with our findings above, the PBR shall continue in effect for a total of five consecutive years starting January 1, 2023, with the last adjustment taking effect on January 1, 2027, subject to the findings set forth above.

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stay-out provision, the Company may not seek to terminate its effective PBR plan in order to discontinue revenue decoupling.

V. PBR PERFORMANCE METRICS

A. Introduction

The Company proposed a set of metrics as a component of its PBR proposal (Exhs. ES-CAH/DPH-1, at 10-11; ES-PBR-PLAN-1, at 4-5). The Company states that its proposed metrics are designed to provide transparency associated with the achievement of clean energy and customer service goals and to further the Company's mission of ensuring safe and reliable delivery of electric service (Exhs. ES-CAH/DPH-1, at 10-11; ES-METRICS-1, at 11). Further, the Company states that the proposed metrics are designed to further current Commonwealth policy goals (Exhs. ES-CAH/DPH-1, at 10-11; ES-METRICS-1, at 11). NSTAR Electric's proposed metrics were based initially on metrics developed for the Company's current PBR plan, following the Department's directive in D.P.U. 17-05, at 412, to develop metrics in three categories: (1) improvements to customer satisfaction and engagement; (2) reductions to system peak demand; and (3) strategic planning for climate adaptation and mitigation (Exh. ES-METRICS-1, at 10, 13). The Company proposed additional metrics to account for changes to the Commonwealth's policy goals, namely metrics for solar developer satisfaction, community solar access, electrification, and equity (Exh. ES-METRICS-1, at 41-42). During the proceeding, the Company proposed significant changes to its initially proposed set of metrics (Exhs. ES-METRICS-Rebuttal-1, at 9-32; ES-METRICS-Rebuttal-2).

By the close of the record in this proceeding, the Company proposed a total of ten reporting metrics, three penalty/incentive metrics, and two planning frameworks, across eleven categories (customer satisfaction, customer engagement, producer satisfaction, producer/developer engagement, operations, peak demand reduction, greenhouse gas ("GHG") reduction, electrification, equity/low-income, and resiliency) (Exh. ES-METRICS-Rebuttal-2; Company Brief at App. A). The Company proposes to report results on each metric as part of the annual PBR plan filings (Exh. ES-CAH/DPH-1, at 64-65). In addition, the Company proposes to provide a PBR performance report as part a five-year mid-term filing that summarizes performance on the metrics and recommendations for continuing, modifying, or augmenting the metrics (Exh. ES-CAH/DPH-1, at 93).

B. Company Proposal

1. Customer Satisfaction, Customer Engagement, and Operations Metrics

a. Introduction

The Company proposes the following five metrics in the categories of customer satisfaction and engagement and operations: (1) overall customer satisfaction in the Commonwealth (customer satisfaction); (2) transactional customer satisfaction (customer satisfaction); (3) customer usage of an outage map (customer engagement); (4) digital engagement (customer engagement); and (5) new customer connects (operations) (Exhs. ES-METRICS-1, at 22-27; ES-METRICS-Rebuttal-2, at 1-2).

b. Overall Customer Satisfaction Metric

The overall customer satisfaction metric is based on a survey conducted by J.D. Power that measures customer satisfaction using six factors: (1) power quality and reliability; (2) price; (3) billing and payment; (4) corporate citizenship; (5) communications;

and (6) customer service (Exhs. ES-METRICS-1, at 17; ES-METRICS-Rebuttal-2, at 1). Customer responses to these separate segments are compiled into one final index score (Exh. ES-METRICS-Rebuttal-2, at 1). NSTAR Electric states that during the current PBR term, the Company consulted with J.D. Power to set a target for the customer satisfaction score of 720 by the end of 2022 (Exh. ES-METRICS-1, at 17-18).[39] NSTAR Electric reports that by 2020 it had achieved a score of 739; the Company proposes a target of 759 for 2027 (Exh. ES-METRICS-1, at 21-23). NSTAR Electric states that it set these targets based on the score needed to achieve first quartile ranking among eastern large utility group companies in 2021, and the Company proposes to adjust the targets to maintain that ranking (Exh. ES-METRICS-1, at 23 & n.4).

c. Transactional Customer Satisfaction Index

NSTAR Electric proposes a customer satisfaction index that is designed to measure customer satisfaction associated with: (1) unplanned outages; (2) planned outages; (3) website satisfaction; and (4) contact center (Exh. ES-METRICS-Rebuttal-1, at 19-20). The proposed index score would be developed by summing the scores of survey responses from customers following each type of transaction and dividing by the sum of all respondents

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39 In the current PBR term, NSTAR Electric has tracked customer satisfaction for both the entire Eversource Energy organization and the Company separately (Exh. ES-METRICS-1, at 16, 22). Going forward, the Company proposes to limit the metric to only its operations (Exh. ES-METRICS-1, at 16, 22).

(Exhs. ES-METRICS-Rebuttal-1, at 20; ES-METRICS-Rebuttal-2, at 1).[40] The Company proposes to include this metric in the Service Quality ("SQ") penalty framework, described below (Exhs. ES-METRICS-Rebuttal-1, at 18-19; ES-METRICS-Rebuttal-2, at 1).[41]

d. Use of Outage Map Metric

The Company's outage map provides customers with information such as estimated time of restoration, outage cause, and outage size so that customers can remain informed and make plans in the event of an outage (Exh. ES-METRICS-1, at 25-26). In prior years, the outage map usage metric has measured the total number of customer views of the outage map during both "blue sky" conditions and when the Company's Emergency Response Plan ("ERP") is triggered (Exh. ES-METRICS-1, at 25-26). In this proceeding, the Company proposes to report only on views during ERP events and to report engagements with the outage map as a percentage of total inbound customer communications during these events, rather than reporting a total count of interactions (Exh. ES-METRICS-1, at 25-26). The Company proposes that the calculation will be done on a per-ERP event basis and then

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40 The Company proposes to weight the transaction type by the associated number of survey responses (Exh. ES-METRICS-Rebuttal-1, at 20).

41 The Company does not propose to apply the SQ penalty/incentive framework to the overall customer satisfaction metric because this measure is not necessarily representative of actual interactions with the Company (Exh. ES-METRICS-Rebuttal-1, at 19). NSTAR Electric states that for many customers, their interactions with the Company are limited to billing issues, and that these limited interactions can skew customer satisfaction based on factors that are outside the Company's control (e.g., rising energy costs or increased demand due to weather) (Exh. ES-METRICS-Rebuttal-1, at 19).

averaged across all ERP events for the year, which is intended to account for annual variances in weather (Exhs. ES-METRICS-1, at 26; ES-METRICS-Rebuttal-2, at 1-2). NSTAR Electric reports that in 2020, 58 percent of customer engagements during ERP events were with the outage map, and the Company proposes a customer engagement target of 75 percent by 2027 (Exhs. ES-METRICS-1, at 26; ES-METRICS-Rebuttal-2, at 1).

e. Digital Engagement Metric

The Company's digital engagement metric is designed to track the percentage of total customer engagements that are digital (Exh. ES-METRICS-1, at 27). Digital interactions include bill pay, outage reporting, text message interactions, mobile app interactions, outage status checks, and others, while non-digital customer engagements include customer service phone calls and manual payments (Exhs. ES-METRICS-1, at 27; ES-METRICS-Rebuttal-2, at 2). NSTAR Electric reports that 88 percentage of total customer engagements were digital in 2020, and the Company proposes a target of 91 percent by 2027 (Exhs. ES-METRICS-1, at 27; ES-METRICS-Rebuttal-2, at 2).

f. New Customer Connects Metric

NSTAR Electric proposes a new metric for the percentage of new customer connects completed in accordance with Company targets for timeliness of new service connections (Exhs. ES-METRICS-1, at 44; ES-METRICS-Rebuttal-2, at 3). Specifically, the new customer connects metric will measure the time from the creation of a work order to the point of installation of the customer's meter in number of business days, excluding hold days[42] (Exh. ES-METRICS-1, at 44). The Company proposes to calculate the metric as the percentage of new customer connects that meet certain performance targets out of the total number of new customer connects (Exh. ES-METRICS-1, at 44). The Company and stakeholders developed and agreed upon performance targets that vary depending on the type of service (i.e., simple services, residential developments, complex residential, commercial developments, and commercial service) (Exh. ES-METRICS-1, at 45).[43] The Company proposes a target of 80 percent of connections within the agreed-upon range in year one and to increase the target by 2.5 percent each year until 90 percent is reached in year five (Exh. ES-METRICS-1, at 45-46). Finally, the Company proposes to include the new customer connects metric in the SQ Guidelines penalty framework,[44] as described below (Exhs. ES-METRICS-Rebuttal-1, at 21, 23; ES-METRICS-Rebuttal-2, at 3).

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42 Hold days are delays that are defined as being outside of the Company's control, in the form of waiting for customer payment or waiting for customer permits or easements (Exh. ES-METRICS-1, at 44).

43 Performance target ranges were developed during the Department's Working Group Meetings for Improving and Expediting the Process for new Electric and Gas Interconnections and range from five to eight business days for simple service to 63-121 days for residential developments (Exh. ES-METRICS-1, at 45).

44 The SQ Guidelines refer to the guidelines adopted in Order Adopting Revised Service Quality Standards, D.P.U. 12-120-D (2015) and set forth at D.P.U. 12-120-D, Attachment A.

2. Producer Satisfaction and Producer/Developer Engagement Metrics

a. Introduction

The Company proposes metrics specifically related to the satisfaction and engagement of producer customers ("producers"), which the Company defines as customers that install a solar system (Exh. ES-METRICS-1, at 27-28). The Company proposes the following three producer satisfaction metrics: (1) a producer satisfaction survey (producer satisfaction); (2) hosting capacity map usage (producer/developer engagement); and (3) a solar development timeline (producer/developer engagement) (Exhs. ES-METRICS-1, at 27-28; ES-METRICS-Rebuttal-2).

b. Producer Satisfaction Survey

The Company states that the producer satisfaction survey will measure producer satisfaction associated with: (1) ease of enrollment; (2) ease of connection; (3) timeliness; and (4) helpfulness and communication during the interconnection process (Exh. ES-METRICS-Rebuttal-2, at 2-3). The survey was developed collaboratively by the Company and J.D. Power and is comprised of two surveys, one sent 65 days after the customer is interconnected and another sent 365 days after the customer is interconnected (Exhs. ES-METRICS-1, at 28; DPU 42-3). NSTAR Electric reports that, on a scale of one to ten, the Company scored an average of 7.01 in producer satisfaction in 2019, and the Company sets a target average of 7.5 producer satisfaction for 2027 (Exhs. ES-METRICS-1, at Table 1; ES-METRICS-Rebuttal-2, at 2-3).

c. Hosting Capacity Map Usage Metric

NSTAR Electric states that the hosting capacity map usage metric will measure the sum of visits to the Company's DG hosting capacity websites (Exhs. ES-METRICS-1, at 28-29; ES-METRICS-Rebuttal-2, at 3). The maps provide solar developers with information about remaining capacity at both the circuit and substation level and allow developers to make more informed decisions about the feasibility of adding DG to the distribution system (Exh. ES-METRICS-1, at 28-29). NSTAR Electric reports that it recorded 9,193 visits to the maps in 2020, and the Company proposes a target of over 18,000 visits by 2027 (Exhs. ES-METRICS-1, at 29; DPU 13-5).

d. Solar Development Timeline Metric

The Company states that the solar development timeline metric will measure the duration in business days from creation of a solar installation work order to completion (excluding hold days), and then will calculate the percentage of solar installations meeting certain timeline performance targets by dividing the number of solar installations that meet the targets by the total number of solar installations (Exhs. ES-METRICS-Rebuttal-1, at 20-21; ES-METRICS-Rebuttal-2, at 3). The Company proposes to include the solar development timeline metric in the SQ penalty framework (Exh. ES-METRICS-Rebuttal-1, at 20-21).

3. Proposed Incorporation of Three Metrics into SQ Penalty Framework

The Company proposes to include penalties and incentives for a subset of metrics, determining that such a framework would create transparency and accountability that can be objectively measured (Exh. ES-METRICS-Rebuttal-1, at 22-24). The Company proposes to replace three metrics that also currently are required to be reported under the Department's SQ Guidelines (consumer complaints, consumer credit cases, and service appointments kept), with three of the proposed metrics discussed above (new customer connects, transactional customer satisfaction index, and the solar development timeline) (Exhs. ES-METRICS-Rebuttal-1, at 23; ES-METRICS-Rebuttal-2, at 1, 3).[45] The Company's proposed substitution would take place after three year of data is collected to establish a benchmark for each metric, after which the penalty threshold for each metric would be set at the mean plus one standard deviation, based on the data (Exh. ES-METRICS-Rebuttal-1, at 23).[46] The Company also proposes for a symmetrical incentive to apply to the metrics that are incorporated into the SQ framework (Exh. ES-METRICS-Rebuttal-1, at 23-24). The Company states that the SQ penalty framework is familiar to the stakeholders in this proceeding, as the SQ Guidelines have been extensively vetted before adoption by the Department (Exh. ES-METRICS-Rebuttal-1, at 24).

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45 NSTAR Electric states that it will continue to report on the original SQ Guidelines metrics to ensure that its performance does not diminish (Exh. ES-METRICS-Rebuttal-1, at 24).

46 The Company proposes to apply the same methodology pursuant to the SQ Guidelines; specifically, the threshold benchmark would be set at the Company-specific mean plus one standard deviation using historical, Company-specific data with the benchmark adjusting every three years based on a rolling average until the tenth year when the benchmark becomes fixed (Exh. ES-METRICS-Rebuttal-1, at 23). In addition, under the Company's proposal, the three metrics would each be allocated a 15-percent weight in the SQ penalty framework (Exh. ES-METRICS-Rebuttal-1, at 23).

4. Peak Demand Reduction Metric

The Company proposes to track peak demand reductions from six measures: (1) energy efficiency programs; (2) demand response programs; (3) company-owned storage; (4) company-owned solar; (5) upgrades to standard technologies; and (6) volt/volt-ampere reactive optimization ("VVO") (Exhs. ES-METRIC-Rebuttal-2, at 4-6; DPU 49-1, at 3-4). The Company explains that the measures target reductions to different, non-coincident peaks (e.g., demand response targets ISO New England Inc. ("ISO-NE") system peak, and VVO targets a substation peak) (Exhs. DPU 41-3; DPU 68-9). Therefore, NSTAR Electric does not propose to aggregate the reductions across measures or set a common target based on system peak, but rather the Company intends to set separate baselines and targets for each peak reduction measure (Exh. ES-METRIC-Rebuttal-2, at 4-6; Tr. 5, at 404-407).

5. Climate Adaptation and Mitigation Plan

NSTAR Electric proposes to pursue an updated enterprise-wide[47] climate adaptation and mitigation plan, which focuses on bringing renewable energy to the region and reducing the Company's own emissions (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 3; DPU 23-2). In addition, the Company proposes to adopt a goal of reducing emissions by ten percent from a 2022 baseline by 2027 (Exhs. ES-METRICS-1, at 39-40; ES-METRICS-Rebuttal-2, at 6). NSTAR Electric states that emissions reductions will focus on enabling a cleaner mix of energy on the grid, improving efficiencies in distribution

47 Enterprise-wide includes all of the utility operating companies in the Eversource Energy holding company system.

infrastructure to reduce system losses, reducing electricity and fuel use at facilities by upgrading heating ventilating air conditioning ("HVAC") equipment and lighting to be more efficient, updating fleet vehicles with electric and hybrid models and using alternative fuel sources, and reducing sulphur hexafluoride leaks (Exhs. ES-METRICS-1, at 39-40; ES-METRICS-2, at 4-6).[48]

The climate adaptation and mitigation plan also includes hardening the Company's electric power system to withstand climate change impacts and engaging and supporting stakeholders to pursue a clean energy future (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 3). Specifically, under the climate adaptation and mitigation plan, NSTAR Electric proposes continued development of a substation flood vulnerability model, evaluation of new equipment to improve performance in flooding conditions, and augmentation of the Company's outage prediction model to include climate impacts (Exh. ES-METRICS-1, at 40).

6. Equity and Electrification Planning Frameworks

a. Introduction

Two metrics initially proposed by the Company related to equity and electrification objectives were ultimately reproposed as planning frameworks (Exhs. ES-METRICS-1, at 42,

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48 The Company also notes that, as proposed, emission reductions measured against the target will also come from reducing methane leaks in the natural gas distribution system, as the Company's emissions targets are enterprise-wide and include all operating companies across three states (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 5; DPU 23-2).

46-49; ES-METRICS-Rebuttal-1, at 10-11).[49] As planning frameworks, the Company proposes to commit to a set of principles regarding electrification and equity consistent with the Commonwealth's policy priorities (Exh. ES-METRICS-Rebuttal-1, at 10). The Company's proposed planning frameworks include commitments to meet policy objectives and to increase transparency through annual reporting (Exh. ES-METRICS-Rebuttal-1, at 11, 17). Both planning frameworks would apply to capital investment projects of $20 million or greater (Exh. ES-METRICS-Rebuttal-1, at 12).[50] As planning frameworks, the Company proposes not to measure a baseline or set targets (Exh. ES-METRICS-Rebuttal-1, at 11-12).

b. Electrification Enabling Investment Framework

The proposed electrification enabling investment framework ("electrification framework") guides future infrastructure to be sized to facilitate the Commonwealth's "All Options" pathway for meeting 2050 decarbonization goals (Exh. ES-METRICS-Rebuttal-1, at 13). See The Massachusetts 2050 Decarbonization Roadmap. Specifically, the electrification framework includes the following planning standards for future bulk station projects: (1) to enable 80 percent of the expected EV load for light duty vehicles based on

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49 The Company determined that the concepts of clean energy/electrification and equity are not well suited to a quantitative metric at this time (Exh. ES-METRICS-Rebuttal-1, at 10). Further, the Company also removed from its proposal a community solar access metric because the Department has not yet approved a community solar program (Exh. ES-METRICS-Rebuttal-1, at 10 & n.3).

50 NSTAR Electric proposed the $20-million threshold because this level is the minimum cost of substation expansion; the threshold is therefore intended to capture every substation expansion that would be needed for electrification enablement (Tr. 5, at 383).

unmanaged charging behavior; (2) to enable 50 percent of charging for medium and heavy duty EVs; (3) to provide four fast charging stations at 150 kilowatt hour ("kWh") each for every 50 miles of interstate roadway covered within the Company's service area with a 75-percent utilization; and (4) to enable conversion of 100 percent of residential and 78 percent of commercial heating load to heat pumps, and 22 percent of commercial heating load to electric heating (Exh. ES-METRICS-Rebuttal-1, at 13-14). The Company proposes to include in its annual PBR filing a report on any bulk station project initiated during the PBR plan term and how it complies with the electrification framework (Exh. ES-METRICS-Rebuttal-1, at 14).[51]

c. Equity Framework

NSTAR Electric proposes an equity framework that would be applied to projects in all Environmental Justice ("EJ") communities (Exhs. ES-METRICS-Rebuttal-1, at 14-16; ES-METRICS-Rebuttal-3; RR-DPU-21).[52] NSTAR Electric states that the equity framework consists of initial steps toward increased efforts to integrate equity considerations in the Company's decision making and in community engagement (Exh. ES-METRICS-Rebuttal-1, at 15). The Company identifies the following five methods for increasing stakeholder

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51 The Company also proposes to include an explanation for how its bulk station project is sized to meet the proposed criteria in the need assessment supporting an application for approval to site the project (Exh. ES-METRICS-Rebuttal-1, at 14).

52 The Company will adopt the Commonwealth's definition of EJ Community as defined in Chapter 8 of the 2021 Climate Act, using the Executive Office of Energy and Environmental Affairs' population criteria, or another definition promulgated by the Commonwealth (RR-DPU-21).

engagement on equity issues that will be applied through the framework: (1) rigorous EJ mapping; (2) identification of stakeholders and focused outreach to those stakeholders; (3) language translation and live interpretation services; (4) public engagement utilizing a variety of communication channels and in multiple languages, as applicable; and (5) collection of feedback (Exhs. ES-METRICS-Rebuttal-1, at 16-17; ES-METRICS-Rebuttal-3). NSTAR Electric proposes to include in its annual PBR filing a description of the Company's actions to implement the planning framework (Exh. ES-METRICS-Rebuttal-1, at 17-18).

7. Resiliency Metrics

In response to intervenor and Department requests, the Company developed two metrics related to system resiliency. First, based a recommendation by TEC and PowerOptions, the Company proposes a reporting metric on Momentary Average Interruption Frequency Index ("MAIFI"), and states that such reporting will be limited to devices with SCADA[53] visibility until advanced metering infrastructure ("AMI") meters are deployed (Exh. ES-METRICS-1, at 25-26; Company Brief at 123-124, App. A at 7).[54] Second, in response to a Department record request, the Company proposes "all-in" System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index

53 SCADA refers to the Supervisory Control and Data Acquisition system that monitors substations, transformers, and other electrical assets.

54 The Company states that following deployment of AMI meters, momentary data from each customer will be integrated into the momentary outage dashboard to provide a more accurate MAIFI score (Exhs. METRICS-Rebuttal-1, at 26; DPU 68-7).

("SAIFI") metrics as part of its annual PBR metric reporting to measure system resiliency (RR-DPU-16). The Company states that, unlike current measures that exclude certain major event days, its proposed all-in metrics will capture all customer interruptions and customer interruption duration without excluding major event days (RR-DPU-16). NSTAR Electric states that by creating parallel SAIDI and SAIFI evaluations that include major events, the Company's understanding and accounting of the impact of resiliency measures on reliability will improve (RR-DPU-16). Further, NSTAR Electric states that the all-in SAIDI and SAIFI metrics will remain reporting-only metrics until sufficient data has been collected to establish a baseline and target (RR-DPU-16).

8. Low-Income Terminations Metric

In response to a request from the Low-Income Network, the Company proposes to include a metric that will provide reports on low-income customer service terminations (for nonpayment and for accounts with past due balances at levels eligible for disconnect) by census tract (Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1). The Company proposes to report data starting pre-pandemic with the 2019 calendar year (Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General argues that the Company is generally proposing to reuse the metrics proposed in NSTAR Electric Company, D.P.U. 18-50, which have not yet been approved and were shown by the Attorney General and other intervenors to be deeply flawed (Attorney General Brief at 65-66).[55] Further, the Attorney General contends that the Company's additional, new metrics proposed for the 2023-2027 PBR term are either flawed or underdeveloped and cannot measure or ensure whether the Company's proposed PBR plan delivers any benefits to ratepayers that would be attributable to the PBR mechanism (Attorney General Brief at 66; Attorney General Reply Brief at 10-11). In particular, the Attorney General claims that NSTAR Electric's proposed metrics are overly focused on incentivizing spending rather than achieving performance goals, and would, therefore, trigger increases in required revenues and customer rates (Attorney General Brief at 77, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 13). According to the Attorney General, the Department should not approve any extension or replacement PBR plan for NSTAR Electric unless and until the Company identifies and corroborates meaningful benefits to ratepayers that can be attributed directly to, or enabled by, the substantial increase in annual revenues occasioned by the PBR plan and can be adequately measured and verified (Attorney General Brief at 66). Thus, the Attorney General asserts that the Department, the Company, and affected stakeholders all need to devote more thought and creativity to identify meaningful performance goals for a PBR plan – in terms of measurable performance outputs – before approving a PBR mechanism for NSTAR Electric (Attorney General Brief at 66).

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55 Additionally, the Attorney General contends that the Company is unable to show that it has met its metrics for the 2018 to 2022 PBR term (Attorney General Brief at 66, 68).

Alternatively, if the Department approves NSTAR Electric's proposed PBR plan, the Attorney General argues that implementation of the PBR term should be delayed until the Company develops, and stakeholders review and comment on, metrics that ensure accountability, and will measure benefits that can be attributed to or enabled by the annual increase in PBR revenues (Attorney General Brief at 65-66). The Attorney General further asserts that the Department should require the Company and affected stakeholders to collaborate to identify documented outcomes that ensure progress in the clean energy transition and require the Company to document and demonstrate progress towards agreed-upon milestones and benchmarks (Attorney General Reply Brief at 13).

b. Overall Customer Satisfaction Metric

The Attorney General argues that the Company's proposed overall customer satisfaction metric does not represent a commitment to improve customer service and would not incentivize performance gains (Attorney General Brief at 70). The Attorney General contends that the customer satisfaction metric is the only customer-service-related metric that includes an objective, quantifiable target (Attorney General Brief at 68 n.73).[56] Further, the Attorney General claims that score improvements in prior years with and without a PBR plan in place indicate that a PBR plan is not essential to improve customer service (Attorney General Brief at 69). Finally, the Attorney General argues that the Company's proposed

[56] The Attorney General cites to the Eversource Energy organization's score of 711, which she argues fell short of the 2022 target of 720 set for the Company's current PBR term (Attorney General Brief at 69 n.74, citing Exh. ES-METRICS-1, Table 1).

2027 target score of 759 represents what it could achieve conducting business as usual and that it is unlikely to result in a first quartile ranking among industry peers in 2027 (Attorney General Brief at 70, citing Exh. ES-METRICS-1, at 23 n.4).

c. Customer Total Satisfaction Index and Solar Development Timeline

The Attorney General contends that while customer service improvements and adherence to a solar development timeline are important performance areas that the Department should track and measure, including these two measures in the existing SQ reporting is highly problematic (Attorney General Brief at 75, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 9). First, the Attorney General argues that replacing the metrics would necessitate a consideration of whether the current cap placed on SQ penalties remains appropriate, considering potential asymmetry between the cost risk against ratepayers and the penalty risk for the Company (Attorney General Brief at 75, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 11-12). Second, the Attorney General asserts that adding performance measures to the SQ Guidelines may weaken the existing penalty on the established SQ metrics if the Department were to make room for new metrics under the penalty cap (Attorney General Brief at 75). Finally, the Attorney General contends that including these prospective performance measures would be a departure from the Department's practice of reviewing its SQ Guidelines holistically and developing uniform metrics across all companies (Attorney General Brief at 75-76). Thus, the Attorney General asserts that further stakeholder consideration is needed before these metrics are implemented (Attorney General Brief at 76).

d. Peak Demand Reduction Metric

The Attorney General argues that NSTAR Electric's proposed peak demand reduction metric measures only the demand reduction results achieved under programs initiated prior to the Company's current PBR, rather than complying with the Department's directive in D.P.U. 17-05 to propose metrics that track peak demand reductions directly attributable to investments enabled by the PBR itself (Attorney General Brief at 70-71; Attorney General Reply Brief at 13, citing D.P.U. 17-05, at 409-410). Further, the Attorney General contends that the demand reduction targets (e.g., energy efficiency, company-owned solar, upgraded technology investments, and initiation of VVO) are all programs, initiatives, and results that already have been separately funded by ratepayers through explicit customer surcharges and cost recovery mechanisms (Attorney General Brief at 71-72). Thus, the Attorney General asserts that the Company cannot claim these reductions as ratepayer benefits from a PBR plan (Attorney General Brief at 72). Finally, according to the Attorney General, the Company has failed to implement the one metric that the Department ordered that could assess performance under the PBR, namely the percent demand reduction enabled by investments under the PBR plan (Attorney General Brief at 72-73, citing D.P.U. 17-05, at 410; Attorney General Reply Brief at 13).

e. Climate Adaptation and Mitigation Plan

The Attorney General argues that the Company's proposed climate adaptation and mitigation plan is simply a list of routine operations changes and not future commitments to mitigate emissions or harden infrastructure enabled by the PBR plan (Attorney General Brief at 76). According to the Attorney General, the facilitation of new sources of renewable energy supply, company-owned solar, grid modernization investments in voltage reduction and VVO, and more aggressive vegetation management are already separately funded and incentivized by ratepayers, and certain storm hardening improvements are standard construction practices (Attorney General Brief at 76-77). Thus, the Attorney General rejects any notion that these measures are attributable to the Company's performance under a PBR plan (Attorney General Brief at 77).

f. Equity and Electrification Planning Frameworks

The Attorney General argues that the Company's proposals to develop frameworks for assessing progress on clean energy transition and electrification and an improvement of EJ contain no substantive measures (Attorney General Brief at 73, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 6-9). The Attorney General maintains that the proposed electrification framework would shift significant risk of potential overbuilding and overspending onto ratepayers (Attorney General Brief at 73-74, 77-78, citing Exh. AG-DPL-PBR-Surrebuttal-1, at 8, 10).[57] Further, the Attorney General asserts that the proposed planning frameworks merit broader inquiry and examination and encourages the

[57] The Attorney General explains that if the Company were directed through an output-focused PBR metric to target 90 percent of future EV charging load as managed load rather than its currently proposed electrification framework that projects to plan all future bulk station upgrades to accommodate up to 80 percent of unmanaged EV charging load, it would enable substantial capital savings and far more capable systems for the Company and its ratepayers (Attorney General Brief at 77-78; Attorney General Reply Brief at 12-13, citing Exh. AG-DPL-PBR Surrebuttal-1, at 9-11).

Department to create a stakeholder review process before the Department allows the Company's proposed PBR plan (Attorney General Brief at 74). Moreover, the Attorney General contends that the electric sector modernization plan development process, required by the 2022 Clean Energy Act, will address the issues that the Company's electrification framework seeks to address, and, therefore, the Department should not approve new planning standards in advance of this legislatively mandated process (Attorney General Brief at 74).

Regarding the Company's proposed equity framework, the Attorney General argues that, if approved, the Department should make clear that demonstrating compliance with the framework does not necessarily satisfy any Company obligation to address EJ or other equity issues in proceedings before the Department (Attorney General Brief at 74 n.77).

2. DOER

a. Introduction

DOER contends that by changing some of its proposed metrics throughout the proceeding, NSTAR Electric demonstrated that the development of effective performance metrics should not only be the Company's responsibility, but rather should involve a broader, more transparent stakeholder process (DOER Brief at 20-21). Further, DOER claims that the Company's proposed metrics do not appropriately incentivize support for clean energy goals, nor do they measure progress under the PBR plan (DOER Brief at 19; DOER Reply Brief at 2).

Despite these concerns, DOER asserts that the proposed metrics should be approved (DOER Brief at 19). DOER, however, recommends that the Department convene a stakeholder proceeding involving the EDCs to develop, over the next five years, more robust performance metrics that include performance incentives and direct benefits to ratepayers of the clean energy transition (DOER Brief at 10, 19-20; DOER Reply Brief at 2-3). In this regard, DOER asserts that the Grid Modernization Advisory Council could be the forum for coordination with stakeholders regarding comprehensive metrics (DOER Brief at 24; DOER Reply Brief at 3). Finally, DOER argues that approval of the Company's proposed metrics may provide additional information that can help develop more effective metrics, but that the Department should not consider the proposed metrics as the end goal (DOER Brief at 20).

b. Equity and Electrification Planning Frameworks

As noted above, the Company initially proposed two metrics related to equity and electrification, but later modified the proposals as planning frameworks (Exhs. ES-METRICS-1, at 42, 46-49; ES-METRICS-Rebuttal-1, at 10-11). DOER disagrees with the Company's position that equity and electrification are not well-suited to a quantitative metric and contends that tracking the benefits of the Company's investments on EJ populations and on electrification goals is both possible and necessary (DOER Brief at 22, citing Exh. ES-METRICS-Rebuttal-1, at 10). DOER supports the Department's approval of the equity and electrification frameworks but asserts that they should be further developed before the next PBR filing (DOER Brief at 21-23).

c. MAIFI

DOER supports the reporting on MAIFI and asserts that these outages will become increasingly important as residential electrification accelerates (DOER Reply Brief at 8, citing

Exh. TEC/PO-JDB-1, at 17; TEC Initial Brief at 12). Further, DOER contends that this metric and any subsequently refined metrics should be consistently applied to all EDCs in future proceedings (DOER Reply Brief at 8-9).

d. Low-Income Terminations Metric

DOER supports approval of the low-income terminations reporting metric (DOER Brief at 21). DOER asserts that maintaining this data would assist the Company and stakeholders in better understanding the scale of low-income ratepayer's service disconnections and assist in identifying potential new policies and programs that would support low-income ratepayers' avoiding disconnections (DOER Brief at 21, citing Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1).

3. Low-Income Network

The Low-Income Network supports implementation of the Company's proposed low-income terminations metric (Low-Income Network Letter in Lieu of Reply Brief at 1). According to the Low-Income Network, the reporting requirement associated with this metric will provide invaluable guidance about the many efforts that the Company is making to maintain affordable bills for low-income customers (Low-Income Network Letter in Lieu of Reply Brief at 1, citing Exh. LI-ES 2-1).

4. Acadia Center

Acadia Center argues that the Company's metrics do not meet the Department's standards and lack financial incentives and consequences (Acadia Center Brief at 15). In particular, Acadia Center contends that the proposed metrics do not go far enough, and that they over-emphasize grid-side capital investment and ignore demand-side flexibility and management (Acadia Center Brief at 16, citing Exhs. AG-DLP-Surrebuttal-1, at 4; AG-DPL-1, at 3). Further, Acadia Center contends that the metrics do not measure benefits attributable to the PBR plan (Acadia Center Brief at 16, citing Exh. UMASS-EP/RS-1, at 59). In addition, Acadia Center asserts that the Department should adopt metrics that meaningfully reduce energy burdens, promote equity, help to accelerate decarbonization of buildings, and reward a utility for ensuring that consumers below the poverty level are on income-eligible rates (Acadia Center Brief at 16). Finally, Acadia Center suggests that a shared savings mechanism that pushes the Company to implement more non-wires alternatives may be useful (Acadia Center Brief at 16).

5. Cape Light Compact

a. Introduction

Cape Light Compact argues that the Department should expedite issuance of its Order in D.P.U. 18-50 to provide due process to intervenors, as the lack of a final decision is unfair to the parties who participated in that docket, and creates confusion as to how those issues will be considered in light of the Company's proposed changes to its metrics in the instant case (CLC Brief at 33-34). Further, Cape Light Compact contends that given the uncertainty over what measures the Company would use for emissions reductions in its climate adaptation and mitigation plan metric and uncertainty regarding how this proceeding interplays with D.P.U. 18-50, the Department should direct a compliance phase or stakeholder review regarding the proposed metrics (CLC Reply Brief at 13-14, citing Attorney General Brief at 74, 78).

b. Climate Adaptation and Mitigation Plan

Cape Light Compact argues that light emitting diode ("LED") lighting replacement should not be included in the Company's climate adaptation and mitigation plan because the Company confirmed that it will complete such replacements by the end of 2022 and LED lighting has become industry standard (CLC Brief at 35-36, citing Exhs. ES-METRICS-Rebuttal-1, at 30; CLC-KFG-1, at 13; CLC-KFG-4; Tr. 5, at 366-367; CLC Reply Brief at 13, citing Company Brief at 124). Cape Light Compact asserts that if the Department approves the Company's climate adaption and mitigation plan with LED lighting replacement included, then it should direct NSTAR Electric to expand its LED replacements to non-LED Rate S-1 (Company-owned) lighting to further reduce emissions (CLC Brief at 33, 36; CLC Reply Brief at 13-14). Finally, Cape Light Compact contends that, despite being outside of the Company's intended scope of Company facility-related emissions, the climate adaption and mitigation plan should be allowed to evolve to where emissions reductions are necessary (CLC Brief at 36, citing Tr. 5, at 373).

6. CLF

CLF also argues that the use of LED lighting is now an industry standard (CLF Brief at 13). As such, CLF asserts that NSTAR Electric should not be rewarded for such measures and that LED lighting replacement should not be included as part of the climate adaptation and mitigation plan (CLF Brief at 13, citing Exh. CLC-KFG-1, at 13-15).

7. TEC and PowerOptions

TEC and PowerOptions argue that the Department should approve reporting on MAIFI as a PBR metric once AMI meters are deployed and also in the interim on an as-available basis (TEC/PowerOptions Brief at 12-13, citing Exhs. ES-METRICS-Rebuttal-1, at 26; DPU 68-7). TEC and PowerOptions assert that a MAIFI metric should have no associated penalties, since the goal is to improve visibility into the operation of the distribution system (TEC/PowerOptions Brief at 12-13).

8. UMass

a. Summary

UMass argues that establishing effective metrics is critical to an effective PBR plan but is difficult and requires stakeholder involvement and focused consideration (UMass Brief at 47). With respect to the Company's proposed metrics, UMass contends that they do not measure benefits that ratepayers may receive that are attributable to the PBR plan, and, therefore, they do not encourage the Company to leverage the PBR plan to customers' benefit (UMass Brief at 51, citing Exh. UMASS-EP/RS-1, at 59; Tr. 5, at 375-376). Further, UMass contends that although the Company's proposal to incorporate financial incentives for performance is a significant and potentially positive step, the proposal was made so late in the proceeding that it has not been fully developed with robust stakeholder engagement and requires refining to align the financial incentives with customer benefits (UMass Brief at 52, citing Exh. UMASS-EP/RS-1, at 59-60).

UMass asserts that the Department should deny NSTAR Electric's proposed PBR plan pending development of acceptable metrics, and then expedite a separate proceeding to finalize metrics (UMass Brief at 48). In this regard, UMass contends that it is the Company's burden to establish adequate metrics, including developing a sufficient record, and that the Department has the authority to reject rate changes if a company fails to meet its burden (UMass Reply Brief at 12 (internal citations omitted)). UMass asserts that delaying the implementation of the proposed PBR plan would not prevent the Department from approving new rates to address the Company's revenue deficiency, but rather would delay automatic rate increases associated with the PBR plan (UMass Reply Brief at 12).

b. Overall Customer Satisfaction Metric

UMass argues that NSTAR Electric's overall customer satisfaction metric should include the Company's ranking relative to peer companies instead of just the Company's absolute numerical score (UMass Brief at 53, citing Exh. UMASS-EP/RS-1, at 62-63, 67).[58] UMass contends that the Company's recent customer satisfaction scores are low compared to other comparable utilities in the region, and that reporting on relative rankings of customer satisfaction would drive the Company to provide a higher level of service (UMass Brief at 53, citing Exh. UMASS-EP/RS-1, at 63-64).

Additionally, UMass argues that NSTAR Electric should also report on the overall satisfaction of its business customers instead of just its residential ones, as business customers

58 UMass asserts that the Company is amenable to reporting relative rankings (UMass Brief at 53, citing Tr. 5, at 399).

have different interests and priorities than residential customers (UMass Brief at 53, citing Exh. UMASS-EP/RS-1, at 62-64, 67). Finally, UMass supports the Company's transactional customer satisfaction metric, as it is more directly focused on the improvement of specific services to customers (UMass Brief at 53, citing Exhs. ES-METRICS-Rebuttal-1, at 18-20; ES-METRICS-Rebuttal-2, at 1; Tr. 5 at 390). However, UMass asserts that this metric alone does not remedy the absence of reporting on business customer satisfaction and relative rankings of customer satisfaction (UMass Brief at 53).

c. Peak Demand Reduction Metric

UMass argues that the Company's peak demand reduction metrics are inadequate since they would not track how the PBR plan resulted in peak demand reduction, but instead only report on the beneficial effects of programs unrelated to the PBR plan (UMass Brief at 53-54, citing Exhs. UMASS-EP/RS-1, at 64-65; ES-METRICS-Rebuttal-2, at 4-6; Tr. 5, at 408, 412-415, 417, 424).

d. Climate Adaptation and Mitigation Plan

UMass argues that because the Company's baselines are inconsistent with the Commonwealth's 1990 baseline, it is unclear whether NSTAR Electric's GHG emissions reduction targets align with Massachusetts policy or whether the Company's GHG reduction efforts are in any way connected to the PBR plan (UMass Brief at 54, citing Exh. UMASS-EP/RS-1, at 65-66; Tr. 5, at 401-402, 403). As such, UMass asserts that the Department should require the Company to present an analysis demonstrating how its own emission reduction targets compare to the Commonwealth's targets and policy (UMass Brief at 54, citing Exh. UMASS-EP/RS-1, at 65-66, 68).

e. Electrification Framework

UMass asserts that the proposed electrification metrics are too open-ended and should instead focus on ensuring that the Company expeditiously delivers the information, and ultimately the implementation, needed for interested customers to convert to electrification (UMass Brief at 52, citing Exh. UMASS-EP/RS-1, at 60-61). According to UMass, the Company should provide annual reporting on customer upgrade requests for electrification that include information on the customer, upgrade, timeline, and load impact (UMass Brief at 52-53, citing Exh. UMASS-EP/RS-1, at 61-62, 67).

9. Company

a. Introduction[59]

The Company rejects the notion that additional process is needed to further develop the metrics, and contends that the intervenors have been unwilling to provide concrete feedback during the instant proceeding (Company Reply Brief at 15, citing Attorney General Reply Brief at 10-13; Cape Light Compact Reply Brief at 13-14; UMass Reply Brief at 11-12).[60] Despite this contention, NSTAR Electric claims that the numerous iterations of

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59 On brief, the Company discusses the metrics proposed in its initial filing and the changes made during the proceeding (Company Brief at 95-117). In the interest of administrative efficiency, the focus of this section will be the Company's response to the issues raised by the intervenors.

60 In response to Cape Light Compact, the Company further notes that any adjustments made to the proposed metrics based on the record in D.P.U. 18-50 should only apply

the proposed metrics throughout the proceeding reflect the Company's effort to take feedback seriously and to incorporate it into its final proposals (Company Reply Brief at 16). The Company recommends that any further process should be conducted during the five-year PBR term, and that the Department should not delay implementation of the PBR plan (Company Reply Brief at 15). In response to DOER's recommendation for a stakeholder process that would address metrics for all EDCs, the Company notes that there are important differences across utilities that need to be considered when developing metrics, and, therefore, company-specific metrics are more appropriate than uniform metrics (Company Reply Brief at 17-18, citing DOER Brief at 3; Exh. DPU 63-4).

In response to intervenor arguments that metrics should be directly tied to PBR adjustments, the Company argues that the PBR mechanism is not designed to recover specific categories of costs, but rather is a formula designed to provide adequate support to meet policy goals (Company Brief at 117, citing Exh. DPU 13-10; Company Reply Brief at 17, 20). As such, the Company contends that it has designed metrics that can measure progress related to policy goals (Company Brief at 118). Further, the Company claims that progress on cost efficiency will not be determined through metrics, but rather based on a review of the drivers of a future request for rate increases (Company Reply Brief at 17, 20, citing Exh. DPU 13-1, at 1 n.1). Therefore, the Company asserts that the intervenors' arguments

on a prospective basis (Company Reply Brief at 19, citing Cape Light Compact Reply Brief at 14).

are insufficient to reach a conclusion that the proposed metrics are deficient (Company Reply Brief at 17, 19-20, citing Attorney General Brief at 12-13; UMass Reply Brief at 11-12).

b. Overall Customer Satisfaction Metric

In response to the Attorney General's arguments, NSTAR Electric contends that Eversource Energy's failure to meet the enterprise-wide customer satisfaction target was due to circumstances beyond the Company's control that affected affiliates outside of Massachusetts (Company Brief at 119; citing Attorney General Brief at 69; Exh. ES-METRICS-1, at 22). Thus, the Company claims that an enterprise-wide measure for judging the efficacy of the Company's PBR plan is inappropriate (Company Brief at 119).

Further, the Company disagrees with the Attorney General's assertion that the Company's overall customer satisfaction target represents a "business as usual" level of service (Company Brief at 119, citing Attorney General Brief at 69-70). NSTAR Electric argues that even if its 2027 target score will not result in a first quartile ranking, it still represents a measure of improvement, and it is appropriate to select a target based on the score currently necessary to get a first quartile ranking (Company Brief at 119, citing Exh. ES-METRICS-1, at 23).

c. Peak Demand Reduction Metric

The Company rejects the notion that energy efficiency and demand reduction measures are not enabled by the PBR plan (Company Brief at 121). In response to the Attorney General, NSTAR Electric contends that the programs included in the peak reduction metric represent a substantial portion of the Company's peak load management efforts and removing them would provide an incomplete picture of the Company's peak reduction efforts (Company Brief at 121, citing Attorney General Brief at 70).

d. Climate Adaptation and Mitigation Plan

In response to the Attorney General's position that the proposed climate adaptation and mitigation plan reflects only what would otherwise be achieved without a PBR plan, NSTAR Electric reiterates that the objective of the PBR plan is to enable long-term planning that aligns with policy objectives, and that the Company's plan to reduce emissions is consistent with such Commonwealth policy objectives (Company Brief at 122, citing Attorney General Brief at 76; Tr. 7, at 477-478).

NSTAR Electric does not disagree with Cape Light Compact's assertions that LED lighting is industry standard practice, and that the Company will have completed its LED replacements by the end of 2022 (Company Brief at 124, citing Exh. DPU 68-22). NSTAR Electric, however, disagrees that LEDs, as a source of emissions reductions, should be removed from the climate adaption and mitigation plan (Company Brief at 124). The Company argues that it has been transparent about how to achieve its emissions reductions, and if it completes installation of LED bulbs, it will increase reliance on other measures to achieve its emissions reductions (Company Brief at 124-125, citing Cape Light Compact Brief at 34; Company Reply Brief at 19, citing Cape Light Compact Reply Brief at 13; Tr. 5, at 367). Further, NSTAR Electric disagrees with Cape Light Compact's recommendation to include non-LED Rate S-1 lighting in the climate adaption and mitigation plan (Company Brief at 125). According to the Company, including non-LED lighting would result in a cost to ratepayers if completed prior to full depreciation, which is expected in approximately two years, at which point the non-LED lighting would be replaced with LEDs (Company Brief at 125, citing Exh. CLC-ES 2-4; RR-CLC-1).

e. Equity and Electrification Planning Frameworks

NSTAR Electric asserts that additional work is needed to gather information through direct communications with EJ communities, and, therefore, the Company proposed to replace its initially proposed equity index metric with the equity framework (Company Brief at 109, citing Exh. ES-METRICS-Rebuttal-1, at 15). Further, NSTAR Electric contends that by proposing equity and electrification frameworks (as opposed to metrics), the Company will have additional time to work with stakeholders to ensure that future metrics to measure progress on these objectives are robust and consistent with the evolving legislative landscape and regulatory and policy developments (Company Brief at 108, 110-111, citing Exh. ES-METRICS-Rebuttal-1, at 11, 14; RR-DPU-17; RR-DPU-18).

NSTAR Electric disagrees with the Attorney General that by converting the metrics into planning frameworks the Company eliminated substantive measures for equity and electrification (Company Brief at 121, citing Attorney General Brief at 73). NSTAR Electric argues that, although it will not be setting a target, the frameworks still will ensure that the Company consistently takes action to meet equity and electrification objectives (Company Brief at 121). Moreover, NSTAR Electric contends that, in lieu of these metrics, the Company has proposed new metrics not included in the initial filing and a penalty/incentive mechanism (Company Brief at 121). Thus, according to the Company, the conversion of two metrics to frameworks did not diminish the accountability created by the proposed metrics (Company Brief at 121). Finally, NSTAR Electric asserts that the electrification framework ensures that the Company's ten-year planning process is in line with the Commonwealth's All Options pathway and does not encourage overspending, as suggested by the Attorney General (Company Brief at 122, citing Attorney General Brief at 78).

f. MAIFI

In response to TEC and PowerOptions' arguments regarding MAIFI reporting, the Company agrees to report MAIFI data for devices with SCADA visibility, so long as this metric would not be subject to penalties (Company Brief at 124). Further, the Company asserts that following deployment of AMI meters, MAIFI from each customer will be integrated into a momentary outage dashboard (Company Brief at 124, citing DPU 68-7).

D. Analysis and Findings

1. Review Criteria

As discussed in Section IV.D.5.a above, the Department has approved a PBR plan for NSTAR Electric with a five-year term. To measure the full range of benefits that will accrue under the PBR plan, the Department finds that it is appropriate to establish a set of broad performance metrics that are tied to the goals of the PBR plan and are consistent with the Department's regulatory objectives.

2. Proposed Metrics

a. Customer Satisfaction, Customer Engagement, and Operations Metrics

The Company proposes a total of five metrics in the categories of customer satisfaction, customer engagement, and operations. First, the overall customer satisfaction metric utilizes J.D. Power's residential customer satisfaction score (Exh. ES-METRICS-1, at 17). The Department finds that the overall customer satisfaction metric appropriately creates a focus on customer service and that J.D. Power is an appropriate independent source for this information (Exhs. ES-METRICS-Rebuttal-2, at 1; ES-CAH/DPH-1, at 112). As suggested by intervenors, the Department finds that the Company's annual target should be a first quartile ranking instead of a specific numerical score (Attorney General Brief at 70; UMass Brief at 53). This measurement will encourage NSTAR Electric's customer satisfaction to improve at rates above the average pace in the industry. If the Company fails to meet the first quartile ranking, NSTAR Electric should explain the aspect(s) of the score (i.e., a low category score in power quality and reliability, price, billing and payment, communications) that impacted the Company's ability to do so. Further, the Department agrees with the UMass's assertion that the Company's J.D. Power business customer satisfaction ranking also should be reported (UMass Brief at 53). Accordingly, the Department directs the Company to include annual reporting on its J.D. Power business customer satisfaction survey results and to target a first quartile ranking.

Second, the transactional customer satisfaction metric will report the results of a customer survey focused on their satisfaction with the Company's: (1) unplanned outages;

(2) planned outages; (3) website; and (4) the contact center (Exh. ES-METRICS-Rebuttal-1, at 19-20). The Company proposes to incorporate the metric into the SQ penalty framework, with a symmetrical incentive (Exh. ES-METRICS-Rebuttal-1, at 19). NSTAR Electric states that the proposed index, unlike the J.D. Power metric, reduces the effect on customer satisfaction of factors outside of the Company's control, such as rising energy costs or increased demand due to weather (Exh. ES-METRICS-Rebuttal-1, at 19). The Department finds that a customer satisfaction metric that removes the impact of certain energy cost increases that are outside of the Company's control is reasonable and useful, as it focuses more directly on improving specific services to customers. In addition, the Department finds that the interactions upon which customers will be surveyed are reasonable and important for the Company to track and target improvement. For these reasons, the Department approves the Company's transactional customer satisfaction metric. The Department, however, rejects the Company's proposal to incorporate this metric into the SQ penalty framework, as discussed in further detail below.

Third, the customer usage of an outage map metric will track the number of unique views during ERP events and report engagements with the outage map as a percentage of total inbound customer communications during these events, rather than reporting a total count of interactions (Exh. ES-METRICS-1, at 25-26). No intervenors commented on the use of outage map metric. The Department recognizes the benefits to customers of accessing service outage status, expected downtime, and the cause of the outage during ERP events. Accordingly, we approve the Company's use of the outage map metric.

Fourth, the digital engagement metric will measure the percentage of customer interactions that are digital (Exh. ES-METRICS-1, at 27). No intervenors commented on the digital engagement metric. 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 tracking the percentage of digital engagements is an important component in this process. Accordingly, the Department approves the Company's digital engagement metric.

Finally, the new customer connects metric is the percentage of new customer connections that meet the target timelines for different types of connections, excluding hold days (Exh. ES-METRICS-1, at 44). The Company is proposing to incorporate this metric into the SQ penalty framework, with a symmetrical incentive (Exhs. ES-METRICS-Rebuttal-1, at 21, 23; ES-METRICS-Rebuttal-2, at 3). No intervenors commented on the new customer connects metric. The Department recognizes the role that electrification will play in meeting the climate goals of the Commonwealth, thus ensuring timely connections for new customers is an important goal. Accordingly, the Department approves the new customer connects metric. We also direct the Company to report data on the number of hold days, and the reason for the hold days. The Department, however, disallows its inclusion in the SQ penalty framework, as discussed in further detail below.

b. Producer Satisfaction and Producer/Developer Engagement Metrics

The Company proposes a total of three metrics in the categories of producer satisfaction and producer/development engagement. The producer satisfaction survey metric will survey interconnecting customers 65 and 365 days after interconnection, and the hosting capacity map usage metric will track the number of hits to the hosting capacity map webpages (Exhs. ES-METRICS-1, at 28-29; ES-METRICS-Rebuttal-2, at 2-3; DPU 42-3). No intervenors commented on these producer satisfaction metrics. The Department acknowledges the increasing role of DER on the electric distribution system. We find that these two metrics are reasonable and appropriate to gauge the services provided to and satisfaction of producers. As such, we allow these metrics.

The third metric is the solar development timeline metric, which will measure the duration from creation of a solar installation work order to completion in business days (excluding hold days), and then will calculate the percentage of solar installations meeting certain timeline performance targets by dividing the number of solar installations that meet the targets by the total number of solar installations (Exhs. ES-METRICS-Rebuttal-1, at 20-21; ES-METRICS-Rebuttal-2, at 3). The Company proposes to incorporate the metric into the SQ penalty framework, with a symmetrical incentive (Exh. ES-METRICS-Rebuttal-1, at 20-21). No intervenors commented on the solar development timeline metric. We recognize the important role that solar power will play in meeting the Commonwealth's energy goals, and that timely connection of solar installations is important component in achieving these goals. Accordingly, the Department approves the

Company's proposed solar development timeline metric. The Department, however, disallows the metric's inclusion in the SQ penalty framework, as discussed in further detail below.

c. Incorporation of Three Metrics into SQ Penalty Framework

The Company proposes to incorporate the new customer connects, transactional customer satisfaction index, and the solar development timeline metrics into the Department's SQ Guidelines (Exhs. ES-METRICS-Rebuttal-1, at 23; ES-METRICS-Rebuttal-2, at 1, 3). The Company also proposes that a symmetrical incentive apply to the PBR metrics that are incorporated into the SQ penalty framework (Exh. ES-METRICS-Rebuttal-1, at 23-24). Several intervenors assert that effective metrics should include incentives and/or penalties (Attorney General Reply Brief at 11-12; DOER Brief at 10, 19-21; Acadia Center Brief at 15; UMass Brief at 52). The Department finds that, in some instances, incentives and penalties are important to the development of meaningful metrics. We recognize, however, that altering the SQ penalty formula may have unintended implications, such as weakening the penalties on existing SQ metrics. Further, the proposal to incorporate these three metrics into the SQ framework was introduced relatively late in the proceeding, and we conclude that the metrics may need refining over time to align the financial incentives with customer benefits. Based on these considerations, we find that the Company's proposal to incorporate these three metrics into the SQ framework warrants more focused attention. Further, we find it prudent for other stakeholders to have an opportunity to propose different potential methods of incorporating penalties and incentives into these metrics. To advance the effort of developing appropriate PBR incentive and penalty metrics, the Company shall track and report the three metrics, without making the proposed changes to the SQ Guidelines. For developing a baseline and target for the transactional customer satisfaction and solar development timeline metrics, the Company should apply the SQ method for establishing a baseline and a target.[61] As discussed in further detail below, the Department finds that tracking and reporting will inform a continued stakeholder dialog on metrics.

d. Peak Demand Reduction Metric

The Company proposes to track peak demand reductions from six programs and initiatives (Exhs. ES-METRICS-Rebuttal-2, at 4-6; DPU 49-1, at 3-4). Several intervenors contend that the proposed metric does not track the impact of investments enabled by the PBR plan, as the Department directed in D.P.U. 17-05 (Attorney General Brief at 70-71; Attorney General Reply Brief at 13; UMass Brief at 53-54). In D.P.U. 17-05 at 409-410, the Department identified system peak demand reduction as an important objective. We find that the Company's proposed peak demand reduction metric is an appropriate starting point for developing a more advanced system peak reduction metric. In particular, we find that reporting on the proposed peak demand reduction metric will provide important data to facilitate the evaluation of benefits associated with energy efficiency programs, demand response programs, company-owned storage, company-owned solar, upgrades to standard

61 NSTAR Electric proposed a baseline and a target based on previous years data for the new customer connects metric, and the Department approves that baseline and target (Exh. ES-METRICS-1, at 45-46).

technologies, and VVO. Based on these considerations, the Department approves this proposed metric. As the Company and stakeholders continue to develop a set of metrics, as discussed below, the parties should consider first whether peak demand reduction is a priority objective, and second, how to develop a robust measure for reductions to system peak demand that are under the Company's control.

e. Climate Adaptation and Mitigation Plan

As noted above, NSTAR Electric proposes to pursue an updated enterprise-wide climate adaptation and mitigation plan, which focuses on bringing renewable energy to the region and reducing the Company's own GHG emissions (Exhs. ES-METRICS-1, at 39; ES-METRICS-2, at 3; DPU 23-2). In particular, the Company proposes to adopt a goal of reducing emissions ten percent from a 2022 baseline by 2027 (Exhs. ES-METRICS-1, at 39-40; ES-METRICS-Rebuttal-2, at 6). The Company states that its proposed metrics are to be designed to create consistency with current Commonwealth policy goals (Exhs. ES-CAH/DPH-1, at 10-11; ES-METRICS-1, at 11). As such, the Company's GHG emissions reduction targets should align with decarbonization objectives in the 2021 Climate Act, and applicable sector-specific interim targets and sub-limits established pursuant to G.L. c. 21N, § 3A. The Company states that it tracks emissions at an enterprise-wide level, including its operating companies in its New Hampshire, Connecticut, and Massachusetts service territories (Exh. DPU 23-2). We conclude, however, that to align with Massachusetts decarbonization goals, it is more appropriate for the Company's emissions reduction goal to reflect GHG emissions and reductions in the Massachusetts service territory only. Similarly, the Company's investments and programs during the PBR term must reflect an appropriate level of climate adaptation. Therefore, while we approve the climate adaption and mitigation plan, we direct the Company in its annual PBR filing to include a demonstration of how the plan is aligned with the objectives of the Commonwealth's decarbonization policies, including applicable sector-specific interim targets and sub-limits established pursuant to G.L. c. 21N, § 3A.

Finally, as discussed above, Cape Light Compact argues that LED lighting replacement should not be included in the Company's climate adaptation and mitigation plan (CLC Brief at 35-36, citing Exhs. ES-METRICS-Rebuttal-1, at 30; CLC-KFG-1, at 13; CLC-KFG-4; Tr. 5, at 366-367; CLC Reply Brief at 13, citing Company Brief at 124). Alternatively, Cape Light Compact asserts that, if the Department approves the Company's climate adaption and mitigation plan with LED lighting replacement included, then it should direct NSTAR Electric to expand its LED replacements to non-LED Rate S-1 (Company-owned) lighting to further reduce GHG emissions (CLC Brief at 33, 36; CLC Reply Brief at 13-14). The Company states that by the end of this calendar year, all Eversource Energy facilities will have undergone a lighting upgrade replacing inefficient fixtures with energy saving LEDs (Exh. DPU 68-22). In addition, the Company reports that it expects non-LED S-1 lighting to be phased out and replaced by LED streetlights in approximately two years (Exh. CLC-ES 2-4). Given these timeframes, the Department finds that it is unnecessary to include LED lighting replacement as part of the climate adaption and mitigation plan. In its annual PBR filings, the Company shall report on its compliance with these timelines; if the Company does not meet these timelines, it shall report on the percentage of S-1 lighting categories of (a) LED and (b) non-LED.

f. Equity and Electrification Planning Frameworks

The Company proposes two planning frameworks through annual reporting, one for equity and one for electrification, applicable to capital investment projects of $20 million or greater and designed to provide commitments to policy objectives and increase transparency (Exh. ES-METRICS-Rebuttal-1, at 10-12, 17). The Attorney General argues that the planning frameworks lack substantive measures and require further examination through a stakeholder process (Attorney General at 73). DOER supports the Department's approval of the frameworks but recommends tracking benefits of the Company's investments in a quantitative manner (DOER Brief at 22).

The Department expects our understanding of how to advance equity as an objective in the oversight of regulated utilities to evolve over time. The Department finds that the proposed framework would benefit from continued development and incorporation of stakeholder feedback to assist in this evolution. The proposed equity framework represents a first step, and is a reasonable and appropriate means, to collect useful data to inform future metrics. As such, the Department approves the equity framework. We note, however, that the Company's compliance with the framework would not necessarily satisfy any obligation to address EJ or other equity issues in proceedings before the Department.

Regarding the proposed electrification framework, the Attorney General contends that the proposal may create a risk of overbuilding and overspending that will be borne by ratepayers, and that the Department should not approve new planning standards ahead of the legislatively mandated process prescribed in the 2022 Clean Energy Act (Attorney General Brief at 74). The Department acknowledges that the Company's planning standards for future bulk station projects have merit, and we recognize that the Company will need to conform with planning criteria that enable a decarbonized future. However, the Legislature's intent is for the comprehensive design and implementation of such standards within the electric sector modernization process outlined in 2022 Clean Energy Act, Section 92B. As such, we decline to approve a prescriptive planning framework related to long-term investments in advance of any legislatively mandated process. Accordingly, we do not approve the Company's electrification framework.

g. Resiliency Metrics and Low-Income Terminations Metric

The Company proposes metrics that were developed based on intervenor feedback, namely two metrics for resiliency (MAIFI and an all-in measure of SAIDI and SAIFI) and a low-income terminations reporting metric (Exhs. ES-METRICS-Rebuttal-1, at 31; LI-ES 2-1; RR-DPU-16; Company Brief at 124, App. A at 7). Intervenors support the approval of the MAIFI-related resiliency metric (DOER Reply Brief at 8-9; TEC/PowerOptions Brief at 12-13) and the low-income terminations metric (DOER Brief at 21; Low-Income Network Letter in Lieu of Reply Brief at 1). No intervenors commented on the all-in measure of SAIDI and SAIFI metric. The Department finds that each of the resiliency metrics and the low-income terminations metric are reasonable, reflects important policy goals, and reports data in a way that promotes transparency. Accordingly, the Department approves the resiliency metrics and the low-income terminations metric.[62]

3. Conclusion

Subject to the findings above, the Department approves the Company's proposed metrics, the proposed equity framework, and the proposed climate adaption and mitigation plan. We deny the Company's proposal to incorporate three proposed metrics into the SQ penalty framework. Further, the Department does not approve the Company's electrification framework. The Department finds that the approved suite of metrics will provide a means of monitoring both the Company's performance and progress toward achieving important policy goals of the Department and the Commonwealth.[63]

The Department appreciates the participation and feedback offered by multiple intervenors. In particular, we acknowledge that several intervenors argued that the Company's metrics would benefit from additional stakeholder feedback, outside of a base distribution rate case proceeding (Attorney General Brief at 65; Attorney General Reply Brief at 13; DOER Brief at 20-21; DOER Reply Brief at 2-3; Cape Light Compact Reply Brief at 13-14; UMass Brief at 48). We recognize that the development of meaningful

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62 The Department confirms that it is not approving any penalty associated with the MAIFI-related metric (Company Brief at 124).

63 The metrics approved in this proceeding supersede those presented in D.P.U. 18-50. As no meaningful issues would remain in D.P.U. 18-50 and in the interest of administrative efficiency, the Department will conclude its investigation in D.P.U. 18-50 and close that docket.

performance metrics should not be the sole responsibility of the Company and should involve a broader, more transparent stakeholder process that will benefit from sharing data and assumptions. The Department also acknowledges that some metrics should incorporate financial incentives and consequences. Thus, while the Department is satisfied that the metrics proposed herein should be approved, subject to the findings above, we direct the Company to coordinate an inclusive stakeholder process over the course of the PBR term to continue to refine the metrics approved herein.

The first step of the stakeholder process should be to define a set of guiding objectives. Then, through the stakeholder process, the Company should refine the metrics approved here, as well as develop a narrow set of new metrics, as needed, to arrive at a comprehensive set of metrics that meet the Department's review criteria and that target improvements to the stakeholder group's stated objectives. Finally, while some reporting-only metrics are valuable for monitoring performance and sharing information and data, at least a subset of key metrics should be tied to incentives and penalties. As a general guideline, incentive/penalty mechanisms should be symmetrical.

The Department directs the Company to report on the progress of the metrics development process in the annual PBR filings. Specifically, the Company shall report on the number of stakeholder meetings held, a list of the stakeholders that participated, and meeting agendas and minutes. The Company shall report on any proposed mutually-agreed upon changes to the metrics approved herein, any new metrics, and any areas of disagreement among the stakeholders. The Department will consider the proposed metrics during our review of the annual PBR filings based on the outcomes of the stakeholder process. The Department's expectation is that the Company and relevant stakeholders will reach agreement on a set of meaningful metrics that, if adopted by the Department, will remain in place should the Company decide to request an extension of the PBR plan term (see Section IV.D.5.a above). To the extent that NSTAR Electric seeks to continue the PBR plan approved herein after the five-year term expires, it shall submit a proposal that lists and defines the metrics that the Company and stakeholders have developed, reports on all other proposals that were considered, and summarizes the final positions of stakeholders on each metric. If the metrics are quantitative, the metrics may include symmetrical incentives and penalties for Department consideration. This proposal shall be filed at least six months in advance of the end of the PBR plan term.

Finally, the Department will consider opening a generic proceeding to direct the development of a common set of electric utility metrics or guidelines, by which future PBR plans can be guided. If a generic proceeding is opened, the Department may modify the foregoing directives relative to NSTAR Electric's stakeholder process.

VI. RATE BASE

A. Introduction

As of December 31, 2021, NSTAR Electric had a rate base of $4,286,717,212 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)). From this amount, the Company subtracted

$191,528,926 to remove grid modernization, Solar Program investments,[64] and the associated deferred income tax for a total proposed rate base of $4,095,188,286 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).[65] NSTAR Electric's total proposed rate base consists of: (1) $5,304,246,946 in net utility plant in service; (2) $57,121,673 in materials and supplies; and (3) $54,964,283 in cash working capital, less (1) $744,331,898 in accumulated deferred income taxes ("ADIT"); (2) $532,319,565 in net FAS 109 regulatory liabilities; and (3) $44,493,152 in customer deposits and advances (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).

B. Plant Additions

1. Introduction

As of December 31, 2021,[66] NSTAR Electric proposes a utility plant in service balance of $7,900,933,940 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)). The reserve for depreciation balance as of the same date was $2,596,686,994, yielding a net plant balance of $5,304,246,946 (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).

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64 The Company removed Solar Program costs associated with the former WMECo's solar facilities pursuant to G.L. c. 164, § 1A(f), as added by the Green Communities Act, and approved in a stipulation agreement in Western Massachusetts Electric Company, D.P.U. 09-05 (2009) (see n.165 below). The Department has allowed inclusion in rate base of the Solar Expansion Program investments, pursuant to our findings in Section XIV.B.4 below.

65 NSTAR Electric's pro forma adjustment includes a decrease of $201,017,135 in net utility plant less $9,488,209 in accumulated deferred income taxes (Exh. ES-REVREQ-2, Sch. 29 (Rev. 4)).

66 In Section IV.D.5.e above, the Department approved NSTAR Electric's proposal to include the Company's 2021 plant additions in rate base without regard to the size of the plant additions in relation to rate base.

2. Project Documentation

NSTAR Electric manages its capital authorization process in accordance with a project authorization policy (Exhs. ES-ADDITIONS-1, at 16; ES-ADDITIONS-11). The project authorization policy sets forth classifications based on the size and nature of a project and sets documentation requirements for each classification (Exh. ES-ADDITIONS-11E at 121-124). Specific projects are those that exceed or are expected to exceed certain cost thresholds (Exh. ES-ADDITIONS-11E at 121).[67] Each specific project requires a project authorization form, which includes: (1) a project description and objectives; (2) a scope and justification; (3) a financial evaluation; (4) a risk assessment; (5) alternatives considered; (6) a technology assessment (for information system projects only); (7) a project schedule; (8) project milestones; and (9) an implementation plan (Exh. ES-ADDITIONS-1, at 16-17). Annual programs, also known as blanket programs, consist of projects and work orders that are similar, small, or routine capital jobs performed over the course of a year with costs below the specific project thresholds (Exhs. ES-ADDITIONS-1, at 13; ES-ADDITIONS-11E,

[67] For most distribution operations projects placed in service between 2016 and 2021, the specific project threshold is $100,000 in direct costs. For distribution operations projects placed in service between 2016 and 2017 in WMA, however, the threshold is $100,000 in total costs. For transmission and shared services projects, the specific project threshold is $500,000 (Exh. ES-ADDITIONS-1, at 34). Effective January 1, 2022, the Company increased the specific project threshold for all distribution operations projects from $100,000 in direct costs to $500,000 in total costs, aligning the requirements of distribution, transmission, and shared services projects (Exhs. ES-ADDITIONS-1, at 20; ES-ADDITIONS-11F at 154). The project authorization form threshold change does not pertain to any capital additions proposed for inclusion in rate base in this proceeding.

at 121). One project authorization form is prepared for the projects under an annual program (Exh. ES-ADDITIONS-11E, at 121).

For the purposes of documentation provision, NSTAR Electric provided several listings of its capital additions, including: (1) a summary of its total capital additions by year; (2) NSTAR Electric's plant in service by year reconciled to the respective FERC Form 1 accounts; and (3) a chronological list of all NSTAR Electric projects and work orders for specific projects with direct charges over $100,000 and blanket work orders/programs, which includes cost estimates, revised estimates, actual direct costs, and cost variances (Exhs. ES-ADDITIONS-1, at 30-32; ES-ADDITIONS-2 & Supp.; ES-ADDITIONS-3 (East) & Supp.; ES-ADDITIONS-3 (West) (Rev.) & (Supp.); ES-ADDITIONS-4 (East) & Supp.; ES-ADDITIONS-4 (West) & Supp.). The Company further organizes its plant additions into the project classifications that reflect distinct documentation requirements, including: (1) specific projects with direct charges over $100,000; (2) blanket work orders/programs with direct charges over $100,000; (3) specific projects over $50,000; (4) blanket programs over $50,000; (5) specific projects under $50,000; (6) blanket work orders and programs under $50,000; and (7) shared services and transmission projects with total costs over $500,000 (Exh. ES-ADDITIONS-1, at 27). To support the costs of the capital additions included in these listings, the Company provided copies of the project authorization forms, supplemental project authorization forms,[68] variance analyses, delegate of authority approvals, and closing reports (Exhs. ES-ADDITIONS-1, at 33; ES-ADDITIONS-5 & Supp.).

3. Positions of the Parties

The Company argues that it has properly supported the net plant-in-service through December 31, 2021, with actual computations and thousands of pages of supporting documentation (Company Brief at 292). According to the Company, the supporting documentation includes project cover sheets, approved amounts, actual costs, cost variance information, and closure papers (Company Brief at 292, citing Exhs. ES-ADDITIONS-1, at 30-33; ES-ADDITIONS-4 (East) and (West) & Supps.; ES-ADDITIONS-5 & Supp.; ES-ADDITIONS-7 & Supp.; ES-ADDITIONS-12(b)). NSTAR Electric contends that the record demonstrates that the Company's capital additions submitted for approval in this case are prudently incurred and used and useful in providing service to customers (Company Brief at 292). Additionally, the Company argues that its capital budgeting and authorization process assures cost containment (Company Brief at 294, citing Exh. ES-ADDITIONS-1, at 12-18). Thus, NSTAR Electric asserts that its capital projects through December 31,

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68 The Company requires supplemental project authorization forms when project costs exceed or are expected to exceed the initially authorized budgeted amount by thresholds set based on the size of the project (Exh. ES-ADDITIONS-1, at 17-18).

2021, should be included in rate base (Company Brief at 300). No other party commented on the prudence of NSTAR Electric's plant additions on brief.[69]

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 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

[69] In Section XIV.A.3 and XIV.B.3 below, we address the Attorney General's position concerning NSTAR Electric's proposal to include costs in rate base associated with the Company's SMART Program and Solar Expansion Program investments.

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

To demonstrate its cost control efforts, NSTAR Electric provided information regarding its capital planning and authorization process and project documentation, which included the Company's current and previous project authorization policies and corresponding levels of documentation by project type and dollar threshold, as described above (Exhs. ES-ADDITIONS-1, at 32; ES-ADDITIONS-5). In addition, the Company responded to several Department information requests seeking more information on and clarification of the supporting documentation (e.g., Exhs. DPU 6-1 through DPU 6-10; DPU 17-1 through DPU 17-8; DPU 47-1 through DPU 47-9). Further, in addition to maintaining the project documentation required by the project authorization policy, the Company's project managers review invoices and labor costs charged to projects monthly to ensure that all associated costs are properly charged and senior management reviews the scope, size, design, and status of each ongoing project monthly (Exhs. ES-ADDITIONS-1, at 22-25; AG 9-4).

Based on our review of the Company's testimony, policies, and documentation, the Department finds that NSTAR Electric's cost control measures were reasonable and appropriate.[70] In addition, the record evidence demonstrates that the project costs associated with the Company's plant additions through December 31, 2021, were prudently incurred and

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70 As noted above, the Company revised its project authorization form threshold for specific projects from \$100,000 in direct costs to \$500,000 in total costs effective January 1, 2022. As there are no project costs subject to the new policy included in the Company's rate base and, therefore, no basis in this proceeding upon which to consider the impact of the Company's policy change, nothing in this Order shall be construed as a finding or determination on the reasonableness or appropriateness of the revised project authorization form threshold. The Department cautions NSTAR Electric that, while its project authorization form threshold has increased, projects of lower values remain subject to scrutiny and the requirement that a company maintain adequate documentation to support the prudence of its capital additions. D.P.U. 14-150, at 54-55.

the resulting plant additions are used and useful in providing service to ratepayers. As such, the Department allows these investments in the Company's plant in service.

6. Conclusion

Based on our findings above, the Department finds that the costs of NSTAR Electric's plant additions were prudently incurred, and the resulting plant is used and useful in providing service to the Company's customers. The Department allows a net plant balance of $5,095,400,897. The allowed net plant balance reflects adjustments pursuant to Section XV.C.2 below and is shown on Schedule 4 below.

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 in order 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 (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

NSTAR Electric conducted a lead-lag study to determine its cash working capital requirements (Exhs. ES-REVREQ-1, at 147; ES-REVREQ-5). Consistent with the lead-lag study approved in D.P.U. 17-05, at 121, the cash working capital associated with purchased power expense will be recovered through the Company's basic service cost adjustment provision, and the cash working capital associated with other operating expenses will be recovered through inclusion in the Company's rate base (Exh. ES-REVREQ-1, at 147). Each component uses revenue lag days and expense lead days to determine the cash working capital requirement (Exh. ES-REVREQ-1, at 148). NSTAR Electric conducted its lead-lag study using in-house personnel to update the net lag days associated with each component of its proposed cash working capital allowance (Exh. ES-REVREQ-1, at 147-156).

NSTAR Electric calculated a revenue lag to be used in both the O&M and basic service cash working capital net lag factors. The revenue lag consists of a "meter reading or service lag," "collection lag," and a "billing lag" (Exh. ES-REVREQ-1, at 149). The sum of the days associated with these three lag components is the total revenue lag experienced by NSTAR Electric (Exh. ES-REVREQ-1, at 149). NSTAR Electric calculated a meter reading or service lag of 15.21 days (Exhs. ES-REVREQ-1, at 149; ES-REVREQ-5, Sch. WC-2, at 1). This lag was derived by dividing the number of billing days in the test year by twelve months and then in half to arrive at the midpoint of the monthly service periods (Exhs. ES-REVREQ-1, at 149; ES-REVREQ-5, Sch. WC-2, at 1). The collection lag, which reflects the time delay between the mailing of customer bills and the receipt of the billing revenues from customers, totaled 26.00 days (Exhs. ES-REVREQ-1, at 149-150; ES-REVREQ-5, Sch. WC-2, at 1). The collection lag was obtained by dividing the average daily accounts receivable balance by the average daily revenue amount to arrive at the collection lag (Exhs. ES-REVREQ-1, at 150; ES-REVREQ-5, Sch. WC-2, at 1). Finally, NSTAR Electric applied a billing lag of one day, based on the fact that most of its customers are billed the day after meters are read (Exhs. ES-REVREQ-1, at 150; ES-REVREQ-5, Sch. WC-2, at 1).[71] Based on the foregoing, NSTAR Electric calculated a total revenue lag of 42.21 days by adding the number of days associated with each of the three revenue lag components (Exhs. ES-REVREQ-1, at 151; ES-REVREQ-5, Sch. WC-2, at 1).

NSTAR Electric's O&M cash working capital is comprised of O&M expense, payroll taxes, and property taxes (Exh. ES-REVREQ-1, at 152). NSTAR Electric pays these expenses to finance the activities conducted in service to customers before the Company receives payment from customers for those services (Exh. ES-REVREQ-1, at 152). To calculate the O&M expense lead period, NSTAR Electric disaggregated its O&M expense into eight major cost categories: net payroll; regulatory commission expenses; corporate insurance; other O&M; property taxes; FICA & Medicare; federal unemployment tax; and

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[71] NSTAR Electric made no adjustment in the lead-lag study to account for customers for which additional time is required to process bills (Exh. ES-REVREQ-1, at 150).

state unemployment tax (Exhs. ES-REVREQ-1, at 153; ES-REVREQ-5, Sch. WC-4). NSTAR Electric reviewed test-year payments and calculated the lead days for each category based on either all payments or a sampling of payments (Exh. ES-REVREQ-1, at 153). Once NSTAR Electric 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 9.27 days (Exh. ES-REVREQ-5, Sch. WC-4). NSTAR Electric then subtracted the expense lead of 9.27 days from the revenue lag of 42.21 days to produce a net O&M expense lag of 32.95 days (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-5, Sch. WC-1). NSTAR Electric derived an O&M expense cash working capital factor of 9.03 percent by dividing the net lag days of 32.95 by 365 days (Exh. ES-REVREQ-5, Sch. WC-1). The Company multiplied this factor by the total costs applicable to cash working capital[72] of $608,860,793 to calculate a cash working capital allowance of $54,964,283 (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-2, Sch. 34 (Rev. 4)).

3. Positions of the Parties

On brief, NSTAR Electric 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 139-141). No other party addressed NSTAR Electric's proposed cash working capital calculations.

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[72] These costs are comprised of total O&M expense, less uncollectible accounts, plus taxes other than income taxes (Exh. ES-REVREQ-2, Sch. 34 (Rev. 4)).

4. Analysis and Findings

The Department has reviewed the evidence in support of NSTAR Electric's lead-lag study, and we conclude that NSTAR Electric properly calculated the total revenue lag of 42.21 days to be applied to both the O&M and basic service expense leads (Exhs. ES-REVREQ-1, at 151; ES-REVREQ-5(a), Sch. WC-2, at 1). Further, the Department finds that NSTAR Electric properly calculated the O&M expense lead of 9.27 days and the resulting net lag of 32.95 days (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-5(a), Schs. WC-1, WC-4). NSTAR Electric's proposed O&M net lag factor of 32.95 days is lower than the Department's 45-day convention (Exhs. ES-REVREQ-1, at 155; ES-REVREQ-5(a), Sch. WC-1). Additionally, we find that NSTAR Electric's decision to perform a lead-lag study with in-house personnel was a cost-effective means to determine its cash working capital requirement (Exh. ES-REVREQ-1, at 147). See Bay State Gas Company, D.P.U. 12-25, at 97 (2012). For these reasons, the Department accepts NSTAR Electric's lead-lag study and the resulting O&M cash working capital factor of 9.03 percent (32.95 days/365 days).

Application of the O&M cash working capital factor of 9.03 percent to the level of O&M and taxes other than income tax expense authorized by this Order produces a cash working capital allowance of $51,347,443. The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

D. Accumulated Deferred Income Taxes

1. Introduction

NSTAR Electric proposes an ADIT balance of $744,331,898, comprising its total ADIT balance of $1,266,840,909, less: (1) $513,020,802 in ADIT associated with transmission service; (2) $4,368,022 in ADIT related to grid-modernization-related investments; and (3) $5,120,187 in ADIT associated with solar investments at the end of 2021 (Exh. ES-REVREQ-2, Sch. 1, at 4, Sch. 32 (Rev. 4)).[73]

The Company's proposed ADIT balance includes property- and non-property-related ADIT (Exhs. ES-REVREQ-3, WP 32 (Rev. 4); AG 4-4; AG 24-3). Initially, the Company's non-property-related ADIT included a debit balance of $19,268,711 in ADIT associated with what the Company identifies as "other pension expense" (Exhs. AG 13-8; AG 21-6). Of this amount, $3,435,606 was associated with accelerated pension contributions; $298,750 was associated with transmission-related pension expense; ($6,123) was associated with amortization of plan loss; and $15,540,478 was associated with a reclassification of property- and non-property-related ADIT that the Company represents was required for financial reporting purposes in compliance with Accounting Standards Update ("ASU") 2017-07 (Exhs. ES-RR/CCP/Comp-Rebuttal-1, at 38; AG 21-6; Tr. 1, at 122-124).

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73 In its initial filing, NSTAR Electric proposed an ADIT balance of $733,301,500 based on an adjusted test-year-end balance that included ADIT associated with estimated plant additions during 2021 (Exhs. ES-REVREQ-1, at 146; ES-REVREQ-2, Sch. 1, at 4, Sch. 32). During the proceeding, NSTAR Electric updated all of its rate base line items to reflect balances as of December 31, 2021 (Exh. ES-REVREQ-2, Sch. 1, at 4, Sch. 32 (Rev. 1)).

The Company subsequently revised its proposed "other pension expense" ADIT debit balance amount from $19,268,711 to $3,605,623 by removing the reclassified amount of $15,540,478 from the calculation and revising the remaining amounts as follows: $3,509,996 associated with accelerated pension contributions; $103,087 associated with transmission-related pension expense; and ($7,460) associated with amortization of plan loss (Exh. AG 24-5).

2. Positions of Parties

a. Attorney General

The Attorney General contends that the Company has not explained why its ADIT balances associated with "other pension expense" should be included in rate base and, therefore, did not justify including in rate base the proposed debit balance of $3,509,996 in ADIT associated with accelerated pension contributions (Attorney General Brief at 181-183, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 38; AG 21-6; AG 24-5; Attorney General Reply Brief at 46-47).[74] The Attorney General argues that related to "other pension expense" ADIT should be excluded from rate base, and she calculates a rate base adjustment of $2,448,102[75] based on the Company's allocation to its distribution operations (Attorney

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74 The Attorney General pointed out that the only significant remaining item to decrease the Company's proposed ADIT is $3,509,996 while the rest of the items are either eliminated after her recommended adjustment or are immaterial (Attorney General Reply Brief at 47).

75 In her rebuttal testimony, Attorney General calculated the adjustment as $2,361,907 (Exh. AG-DJE-Surrebuttal-1, Sch. DJE-3S).

General Brief at 181-183, citing Exhs. AG-DJE-1, at 12-14; AG 24-5; Attorney General Reply Brief at 46-47).

In support of her position, the Attorney General contends that while NSTAR Electric initially proposed the inclusion of $15,540,478 in its "other pension expense" balance based on the requirements of ASU 2017-07, the Company properly removed it, but still did not sufficiently explain the remaining ADIT items associated with "other pension expense" (Attorney General Brief at 182, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 38; AG 24-5; Attorney General Reply Brief at 47). More specifically, the Attorney General asserts that NSTAR Electric does not attempt to explain or justify the inclusion in rate base of the remaining $3,509,996 "other pension expense" associated with accelerated pension contributions, and instead offers what the Attorney General considers to be an irrelevant description of the elements of its pension adjustment mechanism ("PAM") (Attorney General Reply Brief at 47 & n. 24). According to the Attorney General, the list of PAM elements is irrelevant to the issue of whether it is appropriate to include in rate base the ADIT related to accelerated pension contributions (Attorney General Reply Brief at 47 & n. 24).

b. Company

The Company argues that it adequately explained that the remaining ADIT items related to other pension expense are not recovered through the PAM, and, therefore, these items are appropriately included in the base distribution ADIT (Company Brief at 221-222, citing Exhs. AG 21-6; AG 24-5; Tr. 1, at 122-125; Company Reply Brief at 64). First, regarding the $3,509,996 in ADIT associated with accelerated pension contribution, the

Company contends that it does not recover contributions to the pension plan through the PAM, and instead, it recovers only actual pension and PBOP O&M-related costs (Company Brief at 222, citing Exhs. ES-RDC-6, Sch. 2; AG 24-5). Further, the Company claims that because it recovers carrying charges on the pension and PBOP prepaid or liability balances net of deferred taxes through the PAM, pension-related contributions are not recoverable through the PAM (Company Brief at 222; Company Reply Brief at 64). In addition, NSTAR Electric asserts that because a portion of its pension and PBOP costs are capitalized, there would be an associated ADIT included in rate base (Company Brief at 221, citing Tr. 1, at 122-125).

Next, the Company argues that the amount of ADIT related to "amortization of plan losses" is included in base distribution ADIT because it is not recovered through the PAM (Company Brief at 222; Company Reply Brief at 65). Finally, the Company asserts that amounts attributable to "transmission" represent unadjusted test-year amounts that are further adjusted in its revenue requirement workpapers (Company Brief at 221-222, citing Exh. ES-REVREQ-3, WP 32, Cols. (F), (H); Company Reply Brief at 65). Therefore, NSTAR Electric contends that its transmission-related ADIT would be adjusted twice if the Department adopts the Attorney General's recommended adjustment (Company Brief at 222; Company Reply Brief at 65).

3. Analysis and Findings

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 difference accumulates and becomes a source of interest-free funds provided by ratepayers and available to the utility to further invest until it is needed to fund the taxes due and payable in the later years. Therefore, ADIT represents 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).

Regarding the Company's revised "other pension expense" ADIT debit balance, if an expense has been deferred on the utility's books and ratepayers were not burdened with the costs, the expense does not exist for ratemaking purposes. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 24-30 (1991); Massachusetts Electric Company, D.P.U. 89-194/195, at 66 (1990). As such, merely categorizing the deferred income taxes as "other pension expenses" that are not recovered through the PAM does not automatically justify their inclusion in the Company's distribution-related rate base. Therefore, in this instance, the Department examines each item associated with the Company's reported other pension expense ADIT debit balance.

First, the Department finds that the Company has appropriately excluded the debit balance of $103,087 in transmission-related other pension expense ADIT from its proposed ADIT (Exhs. ES-REVREQ-3, WP 32 (Rev. 4); AG 24-5). Next, the Department examines the amortization of pension plan loss related ADIT balance of ($7,460) (Exh. AG 24-5).

According to the Company's annual returns filed to the Department, NSTAR Electric's defined pension costs are accounted for in accordance with accounting guidelines, and this treatment is consistent with the Department-approved PAM (Exh. AG 1-2, Att. (1)(d) at 100).[76] Moreover, this liability or asset is remeasured annually and amortized as the actuarial gains and losses and net periodic benefit cost for the pension, which is consistent with the provisions set forth in the PAM (Exh. AG 1-2, Att. (1)(d) at 100). See NSTAR Electric Company and NSTAR Gas Company, D.P.U. 21-132 (2021). The financial statements of the Company's Annual Returns filed with the Department also note that the unamortized portion of above-mentioned liability or asset is amortized through accumulated other comprehensive income to "Other Income" (Exh. AG 1-2, Att. (1)(d) at 134). The record also shows that the Company recorded the net deferred tax asset as of December 31, 2020 (Exh. AG 1-2, Att. (1)(d) at 134). Through this reclassification process, the Company recognizes the defined pension plan related gain or loss annually. In addition, the record shows that NSTAR Electric recorded other income increase of $5.8 million in 2020 and $10.9 million in 2021 from PAM (Exh. AG 1-2, Att. (1)(d) at 60; AG 1-2 (Supp.), Att. (1)(d) at 61). Moreover, the PAM increases the Company's overall earnings for financial reporting purposes though increasing "Other Income" to meet its pension obligation

76 Specifically, the liability or asset recorded to recognize the funded status of the Company's retiree benefit plans is offset by a regulatory asset or liability in the case of a benefit plan asset in lieu of a charge to Accumulated Other Comprehensive Income/(Loss), reflecting ultimate recovery from customers through rates (Exh. AG 1-2, Att. (1)(d) at 134).

(Exh. AG 1-2, Att. (1)(d) at 45, 57). Based on the evidence discussed above, there is insufficient information to support the pension plan loss ADIT (Exh. AG 1-2, Att. (1)(d)). Further, the Company neither explained its pension plan loss nor provided justification for inclusion of other pension expense ADIT in rate base ADIT other than it is not recovered through the PAM (Exhs. AG 21-6; ES-RR/CPP/Comp-Rebuttal-1, at 38; Tr. 1, at 122). Therefore, the Department declines to include the ADIT for pension plan loss in the Company's ADIT balance.

Finally, the Department addresses whether the ADIT debit balance of $3,509,996 associated with accelerated pension contributions should be included in rate base. According to the Company, the reason this ADIT balance needs to be included in rate base is because it is not recoverable in the PAM (Exhs. AG 21-6; Company Brief at 222). The Company, however, has not explained the costs associated with accelerated pension contributions that appear in the record in this proceeding (Exhs. AG 21-6; AG 24-5; Tr. 1, at 122).[77] While the label "accelerated pension contributions" suggests increased amount of pension contributions, it does not provide the reason in context such as the triggers of these accelerated payments and whether they are burdens of the customers. Therefore, the Department finds that the Company has not provided clear and cohesive reviewable evidence

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77 For example, the Company provided information about accelerated share-based compensation and provided the ADIT amount attributable to the CEO and CFO who were vested as of January 1, 2021, according to the Company's long-term incentive plan (RR-DPU-25 & Att.). The Company could have provided similar information on its executive pension contributions policies to support its proposed accelerated pension contributions ADIT.

to support the ADIT associated with accelerated pension contributions. In proceedings brought under G.L. c. 164, § 94, the petitioning utility bears the burden of proof by presenting a clear and reasonable analysis. D.T.E. 99-118, at 7, citing Fryer v. Department of Public Utilities, 374 Mass. 685, 690 (1978); Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 578-579 (1978); see also Metropolitan District Commission, 352 Mass. 18, 24.[78] Therefore, the Department disallows the inclusion of ($7,460) associated with the accelerated pension contributions in the Company's ADIT balance.

Based on the evidence, the ADIT amounts reviewed above are the unadjusted balance at the end of 2021 (Exhs. ES-REVREQ-3, WP 32 (Rev. 4); AG 4-4; AG 4-5; AG 13-8; AG 24-3; AG 24-4; AG 24-5). The unadjusted disallowance totals $3,502,536 (i.e., $3,509,996 + ($7,460)). The Department will derive the representative amount of this total attributable to transmission expense (Exh. ES-REVREQ-3, WP 32 (Rev. 4)). This is accomplished by taking the rate-year total non-property rate base ADIT of $102,452,015, divided by the total adjusted test-year ADIT of $129,108,171 to derive a factor of 79.35 percent reflecting the portion of ADIT net of that related to transmission

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[78] The burden of proof is the duty imposed upon a proponent of a fact whose case requires proof of that fact to persuade the factfinder that the fact exists or, where a demonstration of non-existence is required, to persuade the factfinder of the non-existence of that fact. D.T.E. 03-40, at 52; D.T.E. 01-56-A at 16; D.T.E. 99-118, at 7.

(Exh. ES-REVREQ-3, WP 32 (Rev. 4)).[79] Based on the above, the unadjusted disallowance total of $3,502,536 multiplied by the factor of 79.35 percent, results in an adjusted disallowance amount of $2,779,262. Accordingly, the Department increases the Company's rate base ADIT by $2,779,262.

VII. OPERATION AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. 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. Boston Gas Company, Essex Gas Company, and Colonial Gas Company, D.P.U. 10-55, at 234 (2010); 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.

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79 The total adjusted test-year ADIT is derived from the unadjusted test-year amount minus the non-rate base ADIT (Exh. ES-REVREQ-3, WP 32, Cols. (D), (E), (H) (Rev. 4)).

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); Massachusetts Electric Company, D.P.U. 92-78, at 25-26 (1992).

NSTAR Electric's employee compensation program is based on a total rewards philosophy and includes base pay, variable compensation, and employee benefits (Exh. ES-SL-1, at 3-6). During the test year, NSTAR Electric booked $164,257,262 net of capitalization in payroll expense for union and non-union personnel, including base wages of $144,810,736 and overtime pay of $19,446,526 (Exh. ES-REVREQ-2, Sch. 10, at 4-5 (Rev. 4)). After a normalization adjustment and removal of transmission-related costs, the Company proposed a total test-year adjusted union and non-union payroll expense of $144,958,862 (Exh. ES-REVREQ-2, Sch. 10 (Rev. 4)). NSTAR Electric proposes to increase its union and non-union payroll expense by $13,138,311, which is net of a rate-year transmission increase allocation of $1,772,843 (see Exh. ES-REVREQ-2, Sch. 10 (Rev. 4)).

2. Non-Union Wages

a. Introduction

NSTAR Electric proposes to increase the test-year adjusted non-union payroll expense based on: (1) a non-union wage increase of three percent effective April 1, 2021; (2) a non-union wage increase of three percent effective April 1, 2022; and (3) a non-union wage increase of three percent effective April 1, 2023 (Exhs. ES-SL-1, at 12; ES-REVREQ-2, Sch. 10, at 3, 4 (Rev. 4)).

The Company determined its non-union wage increases based on a comparative analysis of non-union base salaries and total compensation against median base salaries and total compensation in the energy/utility and general industry sectors in the Northeast, using studies performed by Towers Watson (Exhs. ES-SL-1, at 13-16; ES-SL-5; ES-SL-6). The Company also analyzed whether its actual and proposed merit wage increases were in line with the market by surveying the actual and projected wage increases in the energy/utility and general industry sectors (Exhs. ES-SL-1, at 14, 23; ES-SL-7). In addition, the Company provided a historical comparison of non-union base wage increases to union base wage increases (Exhs. ES-SL-1, at 21; ES-SL-5).

b. Positions of the Parties

NSTAR Electric asserts that its non-union employees' compensation costs are reasonable because the Company establishes the base pay for each position in NSTAR Electric and ESC against similar jobs at other employers in the same competitive market (Company Brief at 225, citing Exhs. ES-SL-1, at 10; ES-SL-5; ES-SL-6; ES-SL-7). The Company claims to set the base pay range between 90 percent and 110 percent of the median market rate for its managers to differentiate base compensation among employees with varied skills, experiences, and level of responsibility (Company Brief at 225, citing Exh. ES-SL-1, at 11). The Company also contends that its job-scope level structure along with base pay provides a total cash compensation that is competitive to the energy/utility and general industry sectors (Company Brief at 222-223, 225, citing Exhs. ES-SL-1, at 4; AG 8-75; AG 8-78; AG 8-78; DPU 22-1; DPU 22-2; DPU 22-3; DPU 22-4; DPU 61-1; DPU 61-3; RR-DPU-23; RR-DPU-24; RR-DPU-25; RR-DPU-28; Tr. 5, at 506-507; Tr. 6 at 643, 645-646, 648-650). According to the Company, increases to base pay may take place through merit increases, promotions, progressions on job-scope levels, and market adjustment when deemed necessary (Company Brief at 225-226). With respect to the 2023 payroll increase to non-union employees, the Company claims that management made a commitment to provide the raise on April 1, 2023 (Company Brief at 226, citing RR-DPU-50). Based on these considerations, the Company asserts that it has demonstrated the non-union employee compensation is reasonable and, therefore, should be approved (Companies Brief at 225). No other party addressed this issue on brief.

c. Analysis and Findings

The Department has reviewed the test-year payroll amount and we find that it is verifiable and provides an appropriate basis upon which the Company developed the proposed rate-year non-union payroll expense (Exhs. ES-REVREQ-2, Sch. 10, at 2, 4-5 (Rev. 4); DPU 18-8, Atts. (a), (b); DPU 18-9 & Att.; DPU 40-7 & Att.). The Department's well-established standard for post-test year non-union payroll adjustments requires a company to demonstrate that: (1) the non-union salary increase is scheduled to become effective no later than six months after the date of the Department's Order; (2) if the increase has not occurred, there is an express commitment by management to grant the increase; (3) there is a historical correlation between union and non-union raises; and (4) the non-union increase is reasonable. Boston Edison Company, D.P.U. 85-266-A/85-271-A at 107 (1986); 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).

Two of the Company's proposed non-union wage increases occurred before the issuance of the Department's Order, one on April 1, 2021, and the other on April 1, 2022 (Exhs. ES-SL-1, at 12; ES-REVREQ-4, Sch. 13). Additionally, on August 2, 2022, the Company provided a management commitment letter stating that at least a three-percent payroll increase for non-union employees will take place for the scheduled wage increase in 2023 (Tr. 6, at 616-617; RR-DPU-50). Based on this information, the Department finds that non-union salary increases are scheduled to become effective no later than six months after this Order, and there is a commitment by management to grant the 2023 increase that has not yet occurred.

In addition, Eversource provided a historical correlation of non-union and union wage increases and demonstrated that it has awarded non-union and union pay increases every year since 2013 (Exh. AG 1-41, Att.). Between 2013 and 2020, union wage increases were between 2.5 percent and 3.25 percent, and non-union wage increases were 3.0 percent (Exh. AG 1-41, Att.). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. See Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76 (2008); Essex County Gas Company, D.P.U. 85-59-A at 18 (1988).

With respect to the reasonableness of the non-union wage increases, the Company annually reviews their current and projected salary levels against external energy/utility companies and the general industry to determine if they are competitive to the market median (Exh. ES-SL-1, at 13; Tr. 6, at 618). Specifically, NSTAR Electric compared its current and projected annual base salaries for non-union employees against median annual salaries for comparable positions in the Northeast by using survey data from a Towers Watson study (Exhs. ES-SL-1, at 14-17; ES-SL-5; ES-SL-6; ES-SL-7; AG 32-4; AG 32-5; AG 32-6). This comparison showed that non-union base salary and total cash compensation are two percent above market median for NSTAR Electric, and one percent above market median for ESC (Exhs. ES-SL-1, at 15-16; ES-SL-5; ES-SL-6). The result of the comparison also demonstrated that the non-union employees merit increase of three percent is consistent with the energy industry practice (Exhs. ES-SL-1, at 17-19; ES-SL-7; AG 32-10, Att. at 37). The Department finds that the Company has demonstrated that its total proposed compensation is competitive with the market median and, therefore, is reasonable.

Based on the above, the Department finds that Eversource has demonstrated: (1) non-union salary increases are scheduled to become effective no later than six months after the Department's Order; (2) there is an express management commitment to grant a three percent non-union wage increase that is scheduled to occur after the date of this Order; (3) there is a historical correlation between union and non-union payroll increases; and (4) the non-union wage increases are reasonable. Accordingly, we allow the Company's adjusted non-union payroll expense.

3. Union Wages

a. Introduction

NSTAR Electric proposes to increase the test-year adjusted union payroll expense based on: (1) Local 12004 union wage increases of three percent effective April 1, 2021, April 1, 2022, and April 1, 2023; (2) Local 369 union wage increases of three percent effective June 2, 2021, June 2, 2022, and June 2, 2023; and (3) Local 455 union wage increases of three percent effective October 1, 2021, and October 1, 2022 (Exhs. ES-SL-1, at 10; ES-REVREQ-2, Sch. 10, at 3, 4 (Rev. 4)).

b. Positions of the Parties

The Company asserts that the union employee wages are primarily negotiated through the collective-bargaining process (Company Brief at 226). Further, NSTAR Electric claims that it determines the competitiveness of the union employees' compensation by analyzing the hourly wages of its union employees against median hourly wages of other Companies' employees in the Northeast (Company Brief at 226, citing Exhs. ES-SL-1, at 8; ES-SL-2). As such, the Company asserts that it has demonstrated its union employees' wages are reasonable and that the Department should approve them (Company Brief at 226). No other party addressed this issue on brief.

c. Analysis and Findings

The Department has reviewed the test-year payroll amount and we find that it is verifiable and provides an appropriate basis upon which the Company developed the proposed rate-year union payroll expense (Exhs. ES-REVREQ-2, Sch. 10, at 2, 4-5 (Rev. 4);

DPU 18-8, Atts. (a), (b); DPU 18-9 & Att.; DPU 40-7 & Att.). The Department's standard for post-test-year 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 Department's Order; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be reasonable. D.P.U. 11-01/D.P.U. 11-02, at 174; D.P.U. 96-50 (Phase I) at 43; D.P.U. 95-40, at 20; D.P.U. 92-250, at 35.

The Company's proposed union payroll adjustments appropriately include only those increases that have been granted before July 1, 2023, the midpoint of the first twelve months after the Department's Order in this proceeding (Exhs. ES-REVREQ-2 (Rev. 3), Sch. 10, at 3, 4). The union payroll increases that occurred in 2021 and 2022, as well as those scheduled to occur in 2023 are based on signed collective bargaining agreements between the Company and the respective unions (Exhs. ES-SL-1, at 9-10; ES-SL-3; AG 1-41, Att.; AG 1-42, Atts. (c), (f), (i); AG 1-43, Att.). Thus, the Department finds that the proposed union wage increases are known and measurable.

Further, with respect to the reasonableness of the union wage increases, the Company submitted a comparison of their average union wages with other employers in the Northeast (Exhs. ES-SL-1, at 9; ES-SL-2). The analysis provided demonstrates that hourly rates paid to the Company's union employees are comparable to the median hourly rates other employers in the region pay for the union employees (Exhs. ES-SL-2; AG 32-2; AG 32-3).

Thus, we find that the Company has demonstrated the reasonableness of the union wage increases. Accordingly, we allow the Company's adjusted union payroll expense.

4. Incentive Compensation

a. Introduction

NSTAR Electric's incentive compensation expense represents the portion of wages and salaries paid to non-union employees as part of the total cash compensation, and it is paid in March or April for performance in the prior year (Exh. ES-SL-1, at 21-23). During the test year, NSTAR Electric booked $16,503,810 in incentive compensation expense, net of a transmission allocation and a normalizing adjustment (Exh. ES-REVREQ-2, Sch. 11, at 1, 2 (Rev. 4)). NSTAR Electric proposes $9,682,635 for target-level incentive compensation expense in the rate year (Exhs. ES-REVREQ-1, at 70; ES-REVREQ-2, Sch. 11, at 1, 2 (Rev. 4)). Under the Company's proposal, the rate-year amount includes the test-year incentive compensation expense at the target level of $8,877,981 and a payroll escalation adjustment of $804,654 (Exhs. ES-REVREQ-1, at 69; ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); Tr. 14, at 1529).

NSTAR Electric states that the proposed rate-year incentive compensation expense is lower than the test year because the Company: (1) normalized the test-year level of expense to remove out-of-period and non-recurring items; (2) reduced the revenue requirement to reflect incentive compensation at target levels; and (3) removed the cash incentive for both the chief executive officer ("CEO") and chief financial officer ("CFO"), consistent with the Department's findings in D.P.U. 17-05 and D.P.U. 19-120 (Exh. ES-REVREQ-1, at 68).[80]

b. Positions of the Parties

The Company asserts that its incentive compensation program is designed to award employees based on individual performance against the predetermined goals once the incentive pool is established after reaching its business objectives (Company Brief at 227). NSTAR Electric contends that to ensure its employees are committed to meeting customers' needs, it sets employee performance goals based on providing safe and reliable services at reasonable costs to customers (Company Brief at 227). Further, NSTAR Electric claims that its total compensation approach is designed to be competitive in the energy/utility and general industrial sectors, thus the incentive compensation remains a necessary mechanism for the Company to stay competitive in the labor market (Company Brief at 222, 227). In addition, NSTAR Electric argues that the incentive compensation included in the revenue requirement is at target level despite the payout exceeding the target level, and that the Company has removed the cash incentive compensation attributable to the Company's CEO and CFO consistent with the Department's previous findings in D.P.U. 17-05 and D.P.U. 19-120 (Company Brief at 228). Therefore, the Company asserts that it has demonstrated its

80 The Department recognizes that Eversource Energy's incentive compensation contains non-cash share-based incentive compensation in addition to the cash incentive compensation (Exh. DPU 61-7; RR-DPU-25). The Department directs the Company to include as part of its proposed revenue requirement in its next base distribution rate case, clearly identifiable information and contemporaneous records on share-based incentive compensation.

incentive compensation expense is reasonable and that the Department should approve it (Company Brief at 227-228). No other party addressed this issue on brief.

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 plan is 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 considers whether the Company's incentive compensation plan is reasonable in design. The record shows that the incentive compensation program for non-union employees is based on individual performance as collaboratively determined by the employee and the employee's supervisor for goals to achieve safety, reliability, and reasonable costs of service to NSTAR Electric's customers (Exh. ES-SL-1, at 22-24; Tr. 6, at 656-667). Each employee's incentive compensation depends on the employee's individual performance and achievement of predetermined goals each year (Exh. ES-SL-1, at 23). Specifically, every February, Eversource Energy holds a compensation committee meeting to review the performance for the previous year and set out the incentive pool available for award (Tr. 6, at 657). An employee's incentive compensation is then tied to the result of the employee's performance review within the team, i.e., an employee can earn up to 200 percent of the target level if the performance review rating is "top achiever," while another employee on the same team would not receive an incentive award if the performance review rating results in a "did not meet expectations" determination (Exh. ES-SL-1, at 23; Tr. 6, at 665-671).[81] This performance review process creates a competitive environment for employees to commit to meeting their goals of providing safe and reliable services at reasonable costs to customers (Exh. ES-SL-1, at 28; Tr. 6, at 665-667). Therefore, the Department finds NSTAR Electric's incentive compensation plan is reasonable in design.

Next, the Department considers whether the Company's incentive compensation expenses are reasonable in amount. NSTAR Electric asserts that it: (1) reduced the incentive compensation expense to the target level of $8,877,981; and (2) added a payroll escalation adjustment of $804,654 to reflect the rate year expense (Exhs. ES-REVREQ, at 69; ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); Tr. 14, at 1529). According to the Company, test-year incentive compensation at target before transmission adjustment was $9,984,671 (Exh. ES-REVREQ-2, Sch. 11, at 2 (Rev. 4)).[82] However, in response to an information request, the Company provided total incentive compensation payout in 2020 of $9,450,872 (Exh. DPU 61-6, Att.).[83] Thus, although the Company maintains that it has been paying the

81 A performance review has five levels: top achiever, exceed expectations, meet expectations, improvement needed, and did not meet expectations (Tr. 6, at 670).

82 The $9,984,671 amount excludes the incentive compensation amount of $555,360 for the CEO and CFO (Exhs. ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); DPU 22-4).

83 The total accrual and payout analysis provided by the Company shows that the total payout of incentive compensation in 2020 is the sum of $7,806,768 and $1,644,104 (Exh. DPU 61-6, Att.).

incentive compensation above target every year since 2010, the actual amount paid in 2020 (i.e., $9,450,872) is less than the target level amount it proposes to include in its revenue requirement (i.e., $9,984,671) (Tr. 6, at 629).

The Department has reviewed the record to determine the derivation of the Company's incentive compensation at target level. The Company states that incentive compensation is a percentage of fixed salary (Tr. 6, at 620-621, 663; Tr. 14, at 1529). NSTAR Electric's test-year incentive compensation amount at target, however, is presented in the Company's revenue requirement exhibit as a hard coded number rather than a percentage multiplying by fixed salary (Exh. ES-REVREQ-2, Sch. 11, at 2 (Rev. 4); Tr. 6, at 620-621, 663; Tr. 14, at 1529). NSTAR Electric attributes this presentation to difficulty in producing information based on the various incentive compensation payout percentages applied to different employee levels and employee groups, so the Company instead relies on the test-year booked expense (Tr. 14, at 1525). Similarly, incentive compensation allocated to NSTAR Electric from ESC based on the Company's accounting records through a cost allocation process and not is determined by multiplying the base salary by the target incentive percentage applicable to each position (Exh. AG 1-36 & Att.(a); Tr. 14, at 1511-1528).

Moreover, the Company presented allocated incentive compensation at target for some employees that exceeds 100 percent of the allocated base salary, e.g., incentive compensation at target amount of $3,028 on a base salary of $38; $5,936 on $29; and $6,860 on $1.29 (Exh. AG 1-36, Att. (a), lines 62, 255, 472). In addressing this irregularity, the Company suggested the Department examine the total amount allocated to NSTAR Electric instead of evaluating individual records, as the allocation method relies on the actual expenses (Tr. 14, at 1517).

Upon examining the evidence, the Department is unable to confirm the accuracy and reasonableness the Company's proposed test-year target level incentive compensation amount. At most, the record shows that the Company's incentive compensation expense is initially budgeted and accrued at target level each year based on percentages of fixed salary, and then adjusted upward around November or December once the mid-year management review determines that the incentive pool will be above the target level (Exhs. AG 1-36, Atts. & Supps.; DPU 22-4, Att.; Tr. 6, at 620-621; 658-659; 663; 668-669). The record, however, does not explain why the total incentive compensation payout is less than the target amount the Company proposes to include in its revenue requirement. Thus, the Department is not convinced that the test-year incentive compensation expense accurately represents the incentive compensation expense at target level. As such, the Department will not rely on the Company's proposed target level of incentive compensation to determine the allowed incentive compensation expense.

In determining the correct incentive compensation expense at target, the Department relies on the Company's derivation method of incentive compensation at target, i.e., multiplying the base salary by the target incentive percentages (Exh. AG 1-36; Tr. 6, at 663; Tr. 14, at 1529). In light of the various target incentive percentages assigned to different level of employees, the Department finds it necessary to calculate a weighted average percentage for NSTAR Electric and ESC respectively in calculating the representative target level of incentive compensation expense (Tr. 14, at 1524-1525). According to information provided by the Company, the overall weighted average percentage is the sum of each employee category's derived weighted average percentage, i.e., the ratio of number of employees to the number of total employees multiplied by the percentage of the target incentive compensation (see RR-DPU-51 & Atts. (b), (c)). This calculation produces a weighted average of 9.98 percent for NSTAR Electric and 9.47 percent for ESC, and when multiplied by the Department approved non-union employee[84] base salaries for the rate year, $20,565,307 for NSTAR Electric and $55,631,228 for ESC, produce the incentive compensation at target level of $2,052,418 for NSTAR Electric and $5,268,227 for ESC, which total $7,320,695 (Exh. ES-REVREQ-2, Sch. 10, at 3 (Rev. 4); RR-DPU-51 & Atts. (c), (b)).[85] Finally, because base salaries include a transmission portion, the Department adjusts the incentive compensation expense to exclude transmission related expense (Exh. ES-REVREQ-2, Sch. 10, at 2, 5 (Rev. 4)). The transmission-related payroll expense of $21,333,143 divided by the total rate-year payroll expense of $179,430,316 derives the factor of 11.89 percent, and when multiplied by the Department-calculated total incentive compensation at target level of $7,320,695, reflects $870,431 of transmission

[84] The Company offers the incentive compensation plan to non-union employees only (Tr. 14, at 1512-1514; RR-DPU-51, at 1).

[85] The Company includes the incentive compensation at target percentage information for employees of NSTAR Electric and ESC and excludes ESC employees whose salaries are never allocated to NSTAR Electric as well as the incentive compensation attributable to the CEO and CFO (Tr. 14, at 1523-1524; RR-DPU-51 & Atts. (b), (c)).

related incentive compensation (Exh. ES-REVREQ-2, Sch. 10, at 2 (Rev. 4)). Therefore, the total distribution related incentive compensation expense at target level is $6,450,264 (Exh. ES-REVREQ-2, Sch. 10, at 2 (Rev. 4)). Accordingly, the Department approves a total incentive compensation expense of $6,450,264 and reduces the proposed incentive compensation by $3,232,371.[86]

5. Employee Health Care Benefits

a. Introduction

NSTAR Electric's health care benefit program includes comprehensive medical, dental, vision, and prescription drug benefits that the Company states are designed to maintain the health of employees and their eligible dependents (Exh. ES-MPS-1, at 4). In conjunction with health benefits, NSTAR Electric also offers wellness programs to help manage and improve employee health, which the Company states helps to moderate health benefit costs over time (Exh. ES-MPS-1, at 4). The Company also sponsors retirement income and health programs to contribute to employees' future financial security (Exh. ES-MPS-1, at 4). The Company states that these benefits are provided in the form of a defined contribution plan and, for a closed group of employees, a defined benefit pension plan (Exh. ES-MPS-1, at 4). Upon retirement, employees who meet certain age and service milestones are also eligible to participate in post-retirement medical plans (Exh. ES-MPS-1, at 4).

86 $9,682,635 - $6,450,264 = $3,232,371.

NSTAR Electric presents an adjusted test-year employee benefits expense of $15,617,670, net of capitalization (Exh. ES-REVREQ-2, Sch. 13, at 1 (Rev. 4)). The Company proposes to increase employee benefits expense by $8,119,338 (Exh. ES-REVREQ-2, Sch. 13, at 1 (Rev. 4)). The Company determines the increases through adjustments of two categories of benefits: (1) medical, dental, and vision expense; and (2) expense exclusion related to pension and PBOP (Exh. ES-REVREQ-1, at 71-72). The proposed increases of employee benefits expense are supported by a 4.8 percent and 4.7 percent annual working rate increase for 2021 and 2022 respectively (Exhs. ES-MPS-2; DPU 51-6). A "working rate" represents the per-employee expected insurance claim levels for the following year and is provided by the Company's benefits consultants and external vendor partners, Cigna and Express Scripts (Exhs. ES-DPH-1, at 58; DPU 45-34).

b. Positions of the Parties

NSTAR Electric argues that the Department should approve its employee health care benefits cost because: (1) the proposed costs are reasonable; (2) the Company has taken appropriate steps to control health care expense of the employees; and (3) the post-test-year adjustments based on the working rate are known and measurable (Company Brief at 228-237). No other party addressed this issue on brief.

c. Analysis and Findings

To be included in rates, health care expenses must be reasonable. D.P.U. 92-78, at 29-30. In addition, any post-test-year adjustments to health care expense must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29;

North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986). Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53-54 (1991).

As an initial matter, the Company derives its rate-year employee benefits costs using the number of active employees participating in the benefits program, which effectively excludes costs related to pension/PBOP from distribution rates (Exhs. ES-REVREQ-1, at 71; ES-REVREQ-2, Schs. 8, at 2; 13, at 3 (Rev. 4); DPU 26-3). This treatment is consistent with Department precedent. D.P.U. 17-05, at 324; D.P.U. 14-150, at 155.

Next, the Department finds that NSTAR Electric's employee benefits costs are reasonable, and that the Company has implemented reasonable and effective measures to contain these costs (Exhs. ES-MPS-1, at 8-11; AG 1-52). For example, the Company introduced a high deductible health plan that encourages consumerism (Exhs. ES-MPS-1, at 8; AG 1-52). The Company also offers opt-out credits to those employees who have alternative health care coverage and elect not to participate in the plans (Exh. AG 1-52). Further, NSTAR Electric consolidated medical carriers so over 98 percent of employee claims are on in-network basis that are more cost effective (Exh. ES-MPS-1, at 7). In addition, the Company negotiated a three-year agreement with a single pharmacy benefit manager coupled with step therapy programs, which provides deeper discounts for prescription drugs, lower administration fees, larger rebates, and utilization-management programs such as step therapy program that encourages the use of lower-cost generic medications (Exh. ES-MPS-1, at 9-10). NSTAR Electric also put its medical and prescription drug programs out to bid to ensure competitive pricing, resulting in all medical plans administered by Blue Cross and Blue Shield of Massachusetts and all prescription drug plans administered by Express Scripts effective January 1, 2019, which yields estimated $1.1 million in savings each year (Exhs. ES-MPS-1, at 11; AG 1-52).

Finally, the Department finds the proposed employee benefits expense based on the working rates developed by the Company's benefits consultant is known and measurable because they are derived from its total plan expense and actual claim data (Exhs. ES-MPS-1, at 11-12; ES-MPS-2; DPU 26-11; DPU 51-6, Att.). The working rates are calculated based on the Company's actual insurance claims and cost trends experienced in the two years prior to the rate year, and, therefore, we conclude that the Company's working rates are sufficiently correlated to its own experience rather than broad-based insurance entities (Exh. DPU 51-6). D.P.U. 18-150, at 241-242; Boston Gas Company and Colonial Gas Company, D.P.U. 17-170, at 103 (2018); D.P.U. 17-05, at 154; D.P.U. 15-155, at 176-177. Based on the foregoing, the Department accepts the Company's proposed health care benefit expenses.

6. Employee Service Awards

a. Introduction

During the test year, the Company recorded $20,727 in employee service awards to residual O&M expense (Exhs. DPU 61-5; AG 8-22, Att.). Under the award program, eligible employees are each presented with a paper certificate and an opportunity to choose a non-monetary service award gift in recognition of their service (Exh. AG 8-22; Tr. 6, at 676). The value of the award starts at $50 for five years of service and the maximum value is $275 for 50 years of service (Exh. AG 8-22).

b. Positions of Parties

i. Attorney General

The Attorney General argues that NSTAR Electric failed to demonstrate the employee service award provides any direct benefits or value to ratepayers (Attorney General Brief at 125, citing Exh. AG 8-22; Tr. 1, at 87; Tr. 6, at 677; Attorney General Reply Brief at 37). Further, the Attorney General contends that the Company failed to support its claim that employee service awards increase employee retention (Attorney General Brief at 125, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 16–18). In particular, she claims that there is insufficient evidence to establish that selecting a non-cash award from a third-party vendor influences an employee's decision to remain with the Company (Attorney General Brief at 125, citing Tr. 6, at 89).[87] In addition, the Attorney General argues that the Company failed to justify the costs are reasonable even if the employee service awards theoretically benefit ratepayers or are standard in the market (Attorney General Reply Brief at 38). In this regard, the Attorney General notes that the Company does not separately

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87 The Attorney General contends that during the evidentiary hearings, the Company's witness could not recall receiving an award separate from the paper certificate, or even if she went to the vendor website to choose the award (Attorney General Brief at 125, citing Tr. 1, at 89).

identify costs for the paper certificate and the non-cash award (Attorney General Reply Brief at 38, n. 19).

Based on these considerations, the Attorney General asserts that the Company is free to recognize its employees' service to the Company, either with paper certificates or other awards, but ratepayers should not pay for the expense (Attorney General Brief at 126; Attorney General Reply Brief at 38). Accordingly, the Attorney General recommends removing the entire amount of employee service award costs from the Company's proposed cost of service (Attorney General Brief at 126; Attorney General Reply Brief at 38).

ii. Company

The Company argues that Attorney General's claims regarding employee service awards are inaccurate and should be disregarded (Company Brief at 170-173). First, NSTAR Electric contends that the employee service awards are standard in the market and must be viewed as part of a complete compensation and benefits package designed to ensure the Company's offering is competitive (Company Brief at 171-172, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 18; Tr. 1, at 87; Tr. 6, at 678-679). Based on surveys the Company relied upon, it claims that 70 percent of industries offer employee service awards to retain employees (Company Reply Brief at 43, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 16).

Second, NSTAR Electric contends that, contrary to the Attorney General's assertion, the Company has demonstrated that customers benefit from the retention of skilled and highly qualified employees to provide safe and reliable service (Company Reply Brief at 44, citing

Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 16-18; AG 8-22). NSTAR Electric states long-term employees acquire institutional knowledge and share it with newer employees, thereby facilitating the learning curves and ensuring effective and efficient customer assistance (Company Brief at 172). In addition, the Company maintains that it is reasonable and prudent to encourage employees who are approaching retirement age to stay in their positions as part of its standard succession planning (Company Brief at 172).

Finally, NSTAR Electric takes issue with Attorney General's claim that the Company failed to demonstrate the employee service awards have an influence on an employee's decision to remain with the Company (Company Brief at 172-173). In this regard, the Company maintains that its witness testified regarding the importance of being acknowledged for her ten years of work in providing safe and reliable service to customers (Company Brief at 172-173, citing Tr. 1, at 87, 90-91; Tr. 6, at 678-679).

c. Analysis and Findings

The Company bears the burden of demonstrating that proposed employee service award costs benefit Massachusetts ratepayers, are reasonable, and were prudently incurred. D.P.U. 11-01/D.P.U. 11-02, at 323; D.T.E. 03-40, at 140-141; Oxford Water Company, D.P.U. 1699, at 13 (1984). This standard applies whether the expenses were incurred at the parent level or at the service company level. D.T.E. 03-40, at 140-141.

The Company explained that the employee service award program is designed to recognize service, to keep employees engaged, and to retain skilled employees to operate the electric and customer service systems and pass along institutional knowledge to newer employees (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 16-18; AG 8-22; Tr. 1, at 87; Tr. 6, at 678). While the prospect of receiving an employee service award alone may not achieve these results, the recognition is part of an overall compensation and benefit package intended attract quality employees who will best serve the Company, and, by extension, customers (Exh. ES-RR/CPP/Comp-Rebuttal-1, at 18; Tr. 1, at 87; Tr. 6, at 678). The Department finds that attracting and maintaining skilled employees ultimately benefits customers through the sustained provision of safe and reliable service (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 16-18; AG 8-22; Tr. 1, at 87). We are not persuaded by the Attorney General's arguments to the contrary.

Further, the Department finds that the modest costs of the employee service award program are reasonable and prudently incurred (Exhs. DPU 26-5, Att.; DPU 61-5; Tr. 1, at 88). Cf. D.P.U. 10-55, at 454-455 & n.288 (expenditures related to shipping executives' wine collection and private school tuition found to be the type of expenses that would not have met Department standard for recovery). In this regard, given the overall costs, we find that it was unnecessary for the Company to segregate the costs of the paper certificate and the award as a prerequisite for recovery. Based on the foregoing considerations, the Department allows the Company to include $20,727 in its proposed cost of service.

B. Depreciation Expense

1. Introduction

During the test year, NSTAR Electric booked $214,446,872 in depreciation expense (Exhs. ES-REVREQ-1, at 112; ES-REVREQ-2, Sch. 25). The Company initially proposed a rate-year depreciation expense of $231,820,683, based on the application of proposed accrual rates resulting from its depreciation study to the Company's projected account balances of depreciable plant as of December 31, 2021 (Exhs. ES-REVREQ-1, at 111-114; ES-REVREQ-2, Sch. 1, at 3, Sch. 25). During the proceeding, the Company updated its proposed depreciation expense to $224,693,975 to reflect the most up-to-date balances of plant in service (Exhs. ES-REVREQ-2, Sch. 1, at 3, Sch. 25 (Rev. 4); ES-REVREQ-3, WP 25 (Rev. 4)).

NSTAR Electric's proposed depreciation accrual rates are the result of a depreciation study as of December 31, 2020, for all electric plant (Exhs. ES-JJS-1, at 2, 5; ES-JJS-2, at 6, 9; ES-JJS-3). The Company estimated the service life and net salvage[88] characteristics for depreciable plant accounts, and next used the service life and net salvage estimates to calculate composite remaining lives and annual depreciation accrual rates for each account (Exhs. ES-JJS-1, at 7-8; ES-JJS-2, at 9). To determine service lives, the Company used the retirement rate method to create life tables, which, when plotted, show an original survivor curve that is then compared to Iowa Curves[89] to determine an average service life for each

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[88] 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 (Exh. ES-JJS-1, at 13).

[89] 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. ES-JJS-1, at 9-10; ES-JJS-2, at 15). Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/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.

plant account (Exhs. ES-JJS-1, at 8-10; ES-JJS-2, at 15, 21). To determine net salvage values, the Company reviewed its actual historical salvage and cost of removal data through 2020 (Exh. ES-JJS-1, at 8, 13-14).

With the exception of general plant assets, the Company relied on the straight-line remaining life method and average service life procedure to determine depreciation accrual rates (Exhs. ES-JJS-1, at 15-16; ES-JJS-2, at 6). For general plant accounts 391.10, 391.20, 393.00, 394.00, 395.00, 397.00, and 389.00, the Company used the straight-line amortization method (Exhs. ES-JSS-1, at 15-16; ES-JJS-3, at 2). Additionally, NSTAR Electric proposed a five-year amortization for its unrecovered reserve (Exhs. ES-JJS-1, at 16; ES-JJS-3, at 2). As part of the depreciation study, the Company also proposed to recover the remaining book value of automated meter reading ("AMR") meters in account 370.10 by year end 2028, to align with the Company's AMI deployment plan and proposal (Exhs. ES-REVREQ-1, at 203; ES-AMI-1, at 21; ES-JJS-1, at 19). To accomplish this, NSTAR Electric proposed a terminal retirement date of 2028, resulting in a proposed accrual rate for account 370.10 of 8.62 percent (Exhs. ES-REVREQ-1, at 203; ES-AMI-1, at 21; ES-JJS-2, at 51, 256; ES-JJS-3, at 1).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject the Company's proposed depreciation accrual rates and instead accept those proposed by her depreciation witness (Attorney General Brief at 143, citing Exh. AG-DJG-1; Attorney General Reply

Brief at 44). The Attorney General contends that NSTAR Electric underestimates service lives associated with five accounts and asserts that the Company has failed to prove that its depreciation accrual rates are not excessive (Attorney General Brief at 144, 153). The Attorney General argues her proposed depreciation rates are reasonable, based on accepted methodologies, and supported by empirical evidence (Attorney General Brief at 144-145, citing Exh. AG-DJG-1, at 7-9; Attorney Reply Brief at 43-44). Further, the Attorney General rejects the notion that her proposed service lives are only based on mathematical curve fitting, and she contends that while mathematical curve fitting was given primary consideration, visual fitting and professional judgment were also relied upon (Attorney General Reply Brief at 43-44).

Specifically, the Attorney General proposes longer average service lives for accounts 361, 362, 365, 366, and 370.20 (Attorney General Brief at 144, 146-151, 152-153). For Account 361 (Structures and Improvements), Account 362 (Station Equipment), Account 365 (Overhead Conductors and Devices), and Account 366 (Underground Conduit), the Attorney General argues that her proposed curves and average service lives provide a better mathematical fit to the Company's historical retirement data (Attorney General Brief at 146-151, citing Exh. AG-DJG-1, at 17-24; Attorney General Reply Brief at 44). For Account 370.20 (AMI Meters), the Attorney General asserts that a longer average service life of 25 years is more consistent with meter manufacturer and Company representations than NSTAR Electric's proposed average service life of 15 years (Attorney General Brief at 152-153). With respect to Account 370.10 (AMR Meters), the Attorney General proposes the same curve and average service life determined by the Company's depreciation study; however, she rejects the application of a terminal retirement date of 2028 and argues that the Company's proposal is driven by an incentive to increase cash flow (Attorney General Brief at 151-152).

Finally, the Attorney General argues the Company has not met its burden of demonstrating that its proposed depreciation expense is not excessive (Attorney General Brief at 153). Based on the above arguments, the Attorney General recommends that the Department approve her proposed depreciation accrual rates and reduce the Company's depreciation expense by approximately $17 million (Attorney General Brief at 153, citing Exh. AG-DJG-1, at 4).

b. Company

NSTAR Electric argues its depreciation study was based on historic plant data and informed by supplemental information from management and personnel, field reviews of the Company's property, estimates used by other utilities, and expert judgment (Company Brief at 238-239). NSTAR Electric asserts that the Attorney General relies exclusively on statistical analysis of the historical data and mathematical fitting, and the Company maintains that such exclusive reliance is inconsistent with authoritative depreciation texts (Company Brief at 239, 243-244, 250; Company Reply Brief at 49-50). As such, the Company argues that the Attorney General's proposed service lives and resulting depreciation accrual rates are flawed and should be rejected (Company Brief at 244, 250).

For Account 361.00 (Structures and Improvements), the Company contends its proposed 75-R3 curve is more realistic and representative of future expectations, and that the Attorney General's proposal ignores the change in asset mix from cement block structures to prefabricated steel and modular structures over time (Company Brief at 245). For Account 362.00 (Station Equipment), NSTAR Electric argues the Attorney General's proposal not only ignores more recent data and changes in substation equipment, but that her proposed curve assumes some assets will survive up to 120 years, which the Company claims is unreasonable (Company Brief at 245-256). With respect to Account 365.00 (Overhead Conductors and Devices), the Company asserts the Attorney General's proposed curve is not representative of the underlying assets, claiming her proposed curve unreasonably assumes assets with lifecycles of over 130 years (Company Brief at 246; Company Reply Brief at 50). Moreover, the Company argues the selection of the O1 type curve for Account 365.00 is problematic as it assumes the same level of retirements by age and ignores wear and tear and other influences on asset retirement and replacement (Company Brief at 246-247). Regarding Account 366.00 (Underground Conduit), the Company argues that the insufficient retirement history makes strict mathematical fitting and reliance solely on statistical results irresponsible (Company Brief at 247; Company Reply Brief at 50). Instead, NSTAR Electric contends the Department should maintain the currently approved 73-R3 curve for this account (Company Brief at 247; Company Reply Brief at 50-51).

Regarding the Company's metering accounts, NSTAR Electric avers that a retirement date of 2028 is appropriate and reasonable for Account 370.10 (AMR Meters) because all

AMR assets will be replaced with newer AMI assets by December 31, 2028 (Company Brief at 247-248). NSTAR Electric argues that if the Department rejects the proposed terminal retirement date but approves the Company's AMI plan, the Company would have approximately $55.7 million in stranded costs in 2028 (Company Brief at 248-249, citing Exh. ES-JJS-Rebuttal-1, at 20-21). The Company further contends this would lead to intergenerational inequity, as future customers would have to pay for assets that are no longer providing service (Company Brief at 248-249). For Account 370.20 (AMI Meters), NSTAR Electric argues a 15-year average service life is appropriate based on existing data and what other electric utilities use (Company Brief at 249, citing Exh. AG 25-2, Att. (a) at 7-8; Tr. 2, at 190, 196-197). The Company insists that AMI meters are technologically different than AMR meters and, therefore, they should have different service lives (Company Brief at 249, citing Exhs. AG 25-1; AG 25-2; Tr. 2, at 192-193). Further, NSTAR Electric claims that its proposed average service life for this account is consistent with its experience and industry practice and should be approved (Company Brief at 250). The Company further clarifies that an average service life of 15 years will have some meters lasting up to 28 years, which it claims is consistent with manufacturer representations (Company Brief at 250).

In conclusion, NSTAR Electric asserts that the Department should adopt the Company's proposed composite accrual depreciation rate of 2.91 percent as it is based on a combination of statistical analyses from a depreciation study, application of the depreciation expert's judgment, and current industry standards (Company Brief at 251). NSTAR Electric argues the Attorney General made no effort in her reply brief to rebut the Company's position and was unable to cite to any evidence that would suggest she relied on anything other than mathematical curve fitting (Company Reply Brief at 49-51).

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; Milford Water Company, D.P.U. 84-135, at 23 (1985); 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 company reaches a conclusion about a depreciation study that is at variance with that witness's 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 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 historic performance to assess future events, a degree of subjectivity is inevitable.[90] 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. 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, preferably through the direct filing and at least in the form of comprehensive responses to well-prepared discovery, the reasons why the preparer of the study chose one particular life-span curve or salvage value over another. The Department will continue to look to the 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 54-55. 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 Department and intervenor review.

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90 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; D.P.U. 1720, at 44; D.P.U. 1350, at 109-110.

b. Accrual Rates

i. Account 361.00 (Structures and Improvements)

The current accrual rate for Account 361 is 1.50 percent, based on a 65-R2.5 curve for the former Western Massachusetts Electric Company ("WMECo") and a 70-R3 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 75-R3 curve, which results in an accrual rate of 1.55 percent, while the Attorney General proposes an 80-R3 curve with an accrual rate of 1.44 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 16-17; AG 7-9, Att.). While the Attorney General argues her curve provides a better mathematical fit with a sum of squared differences ("SSD")[91] of 0.0701 compared to the Company's curve exhibiting an SSD of 0.2142, it is important to note that the Company's analysis looks at two experience bands of data for this account, one from 1901 to 2020 and one from 2001 to 2020, while the Attorney General's analysis only compares her curve to the larger experience band (Exhs. ES-JJS-2, at 70-76; AG-DJG-1, at 16-17). The Company's proposal considers both bands and provides a balance between the two sets of data, whereas the Attorney General's proposal ignores more recent trends in the retirement history (Exh. ES-JJS-2, at 70). The asset's materials in Account 361 have also changed over the years, moving away from cement block structures to prefabricated and modular steel structures, which have been shown to have shorter service lives (Exhs. ES-JJS-Rebuttal-1, at 14-16; Tr. 2, at 202).

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91 SSD is a measure of the distance between the proposed Iowa Curve and the observed life table, such that a lower SSD signifies a better mathematical fit (Exh. AG-DJG-1, at 17).

Moreover, in a review of curve-life combinations used by other utilities, no company uses an average service life for Account 361.00 greater than 75 years, and most appear to use an average service life of 65 years (Exh. DPU 8-2, Att.). Based on the foregoing analysis, the Department finds the Company's proposed 75-R3 curve is reasonable and appropriate. Thus, we approve an accrual rate of 1.55 for Account 361.00 (Structures and Improvements).

ii. Account 362.00 (Station Equipment)

The current accrual rate for Account 362.00 is 2.01 percent, based on a 47-S0 curve for WMECo and a 60-R2.5 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 62-R2.5 curve, which results in an accrual rate of 2.10 percent, while the Attorney General proposes a 69-R2.5 curve with an accrual rate of 1.86 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 18-19; AG 7-9, Att.). Comparing the two curves, the Attorney General's curve has an SSD of 0.0592, and the Company's curve has an SSD of 0.0687, both of which could be considered a reasonable fit (Exh. AG-DJG-1, at 19-20). As with Account 361.00, here the Attorney General compares her proposed curve to only one experience band of data, while the Company's proposal considers two experience bands and attempts to strikes a balance between them to capture temporal shifts in retirement trends (Exhs. ES-JJS-2, at 77-83; AG-DJG-1, at 19). From a visual fitting perspective based on the graphs provided by the Attorney General, the 69-R2.5 curve overshoots most of the data points through age 65, while the Company's curve better approximates these data points (Exh. AG-DJG-1, at 19). Furthermore, the Company's proposed 62-R2.5 curve is consistent with the average service lives utilized by comparable utilities (Exh. DPU 8-2, Att.). Based on the foregoing analysis, the Department finds the Company's proposed 62-R2.5 curve is reasonable and appropriate. Thus, we approve an accrual rate of 2.10 percent for Account 362.00 (Station Equipment).

iii. Account 365.00 (Overhead Conductors and Devices)

The current accrual rate for Account 365.00 is 3.09 percent, based on a 55-R0.5 curve for WMECo and a 48-R0.5 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 60-R0.5 curve, which results in an accrual rate of 2.60 percent, while the Attorney General proposes a 66-O1 curve with an accrual rate of 2.22 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 20-21; AG 7-9, Att.). The Attorney General's curve has an SSD of 0.1008, and the Company's curve has an SSD of 0.1768 (Exh. AG-DJG-1, at 21). Similar to Accounts 361.00 and 362.00, here the Attorney General compares her proposed curve to only one experience band of data, while the Company's proposal considers three experience bands for this account (Exhs. ES-JJS-2, at 96-105; AG-DJG-1, at 21). While the Attorney General's proposed curve provides a better mathematical fit to the larger experience band, the Company's proposal more accurately incorporates trends from more recent experience bands and considers the full set of retirement data points (Exh. ES-JJS-Rebuttal-1, at 19). Additionally, the Company's proposal is consistent with the curve-life combinations used by other utilities, as most utilize average service lives between 45 and 60 years for Account 365, and none use an O-type curve (Exh. DPU 8-2, Att.). As NSTAR Electric points out, the use of an O1 curve assumes the same level of retirements by age, unaffected by other forces of retirement such as wear and tear, which would be an unreasonable assumption (Exh. ES-JJS-Rebuttal-1, at 18-19). Based on the foregoing analysis, the Department finds the Company's proposed 60-R0.5 curve is reasonable and appropriate. Thus, we approve an accrual rate of 2.60 percent for Account 365 (Station Equipment).

iv. Account 366.00 (Underground Conduit)

The current accrual rate for Account 366.00 is 2.12 percent, based on a 65-R1.5 curve for WMECo and a 75-R3 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). The Company proposes a 75-R3 curve, which results in an accrual rate of 2.10 percent, while the Attorney General proposes an 80-R3 curve with an accrual rate of 1.95 percent (Exhs. ES-JJS-3; AG-DJG-1, at 4, 22-24; AG 7-9, Att.). The Attorney General's curve has an SSD of 0.0887, and the Company's curve has an SSD of 0.1998 (Exh. AG-DJG-1, at 24). While the Attorney General's proposed curve provides a better mathematical fit based on the SSD, the retirement history and data points available for Account 366.00 are limited, with less than 15 percent of plant experiencing retirement (Exhs. ES-JJS-2, at 106-112; ES-JJS-Rebuttal-1, at 17). The Department has previously held that when an account has insufficient retirement history mathematical fitting may not be adequately relied upon to suggest a departure from a currently approved average service life and curve combination. D.P.U. 18-150, at 303. Here with a limited number of retirements, the Department does not find a compelling reason to change the 75-R3 curve that is currently used for NSTAR Electric for this account (Exhs. ES-JJS-2, at 106; AG 7-9, Att.). Further, in a review of other utilities it appears most utilize average service lives for Account 366.00 of 75 years or less, with only two out of 89 utilities using an 80-year average service life for this account

(Exh. DPU 8-2, Att.). Based on the Company's limited data and the practices of other utilities, the Department finds it is reasonable to keep the 75-R3 curve currently utilized for Account 366.00. Thus, we approve an accrual rate of 2.10 percent.

v. Account 370.10 (AMR Meters)

The current accrual rate for Account 370.10 is 5.88 percent, based on a 18-L1.5 curve for WMECo and a 23-R1.5 curve for NSTAR Electric (Exhs. ES-JJS-3; AG 7-9, Att.). While the Company's depreciation study and Attorney General both identify the 24-S0.5 curve as best matching the historical data, the Company proposes a terminal retirement date of 2028, which results in a depreciation accrual rate of 8.62 percent (Exhs. ES-JJS-2, at 142; ES-JJS-3; AG-DJG-1, at 4, 24; AG 7-9, Att.). The Attorney General states the terminal retirement date is not appropriate and proposes a depreciation accrual rate of 4.15 percent for Account 370.10 (Exh. AG-DJG-1, at 4, 24; Attorney General Brief at 151-152). The Attorney General acknowledges the Company's planned retirement of AMR meters and suggests it would not be unreasonable to apply a terminal life span to Account 370.10 if all assets are indeed retired by 2028 (Exhs. DPU-AG 2-4; Tr. 11, at 1209, 1217). The Attorney General insists, however, that the Company's proposal with respect to AMR meters is biased and simply a means to increase cash flow (Attorney General Brief at 151-152, citing Exh. AG-DJG-1, at 25-26).

The Department approved NSTAR Electric's AMI implementation plan and model tariff in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B. The Company's proposal to utilize a terminal life span retirement date of 2028 for Account 370.10 (AMR Meters) is consistent with the AMI implementation plan approved by the Department and helps ensure that customers pay for utility assets that are in-service, while limiting intergenerational inequity. Therefore, the Department approves the Company's proposed accrual rate of 8.62 percent for Account 370.10 (AMR Meters).

vi. Account 370.22 (AMI Meters)

For Account 370.22 (AMI Meters) the Company proposes a 15-S2.5 curve, which results in a depreciation accrual rate of 6.92 percent (Exhs. ES-JJS-3; AG 7-9, Att.). The Attorney General did not contest the curve-life combination in testimony, but for the first time on brief suggests that an average service life of 25 years is more appropriate for this account (Attorney General Brief at 152-153). The Attorney General contends that a 25-year average service life is more consistent with manufacturer and Company representations that AMI meters will last 20 years or more (Attorney General Brief at 152-153, citing Tr. 7, at 709, 712). While the Company and meter manufacturers acknowledge an estimated life of 20 years or more for AMI meters, NSTAR Electric accurately points out that utilizing a 15-year average service life for these assets means that some meters will last beyond 20 years, with some lasting up to 28 years (Exhs. ES-JJS-2, at 146; AG 35-1; Tr. 2, at 193, 197-199). Further, with the Company's own limited history for this account, the curve-life combinations used by other utilities can provide a relevant benchmark for industry standards. Currently, no electric utility uses an average service life of 25 years for AMI meters (Exh. DPU 8-2, Att.). Of those utilities with AMI meters, the range of average service lives is 10 to 20 years, with most using a 15-year curve (Exh. DPU 8-2, Att.). Based on the presently available information and the comparison to other electric utilities, the Department finds that a 15-S2.5 curve and corresponding accrual rate of 6.92 percent is appropriate for Account 370.22 (AMI Meters).

c. AMR and AMI Assets

As discussed in Section XV.A below, NSTAR Electric proposes a Company-specific AMI tariff consistent with the AMI implementation plan and model tariff approved in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 9-10, 234, 238-239, 285-286. In the instant proceeding, the Department investigated concerns regarding potential over- or under-collection of metering costs, the tracking of costs, and the potential for recovering all meter-associated costs through the Company's proposed AMI factor ("AMIF") (Exhs. DPU 9-1; DPU 33-3; DPU 43-1; DPU 46-3; RR-DPU-29; RR-DPU-33). As set forth in Section XV.C.2 below, the Department has determined the most prudent course of action is to recover all meter-related capital through the annual reconciling mechanism. As such, the depreciation expense associated with meters (Account 370.10, Account 370.21, Account 370.22, and Account 370.30) must be removed from base distribution rates. The Department reduces the Company's depreciation expense by $26,909,787 to reflect the removal of these assets from rate base (Exh. ES-REVREQ-3, Workpaper 25 (Rev. 4)).[92]

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92 $26,909,787 represents the total depreciation expense associated with metering accounts and is the sum of $17,099,862 associated with Account 370.10 (AMR Meters), $1,047,243 associated with Account 370.21 (Non-AMR Meters – Old Technology), $7,660,959 associated with Account 370.22 (AMI Meters), and $1,101,723 associated with Account 370.30 (Metering Equipment) (Exh. ES-REVREQ-3, WP25 (Rev. 4)).

d. Land and Land Rights

As part of NSTAR Electric's proposed depreciation expense, the Company includes a total of $177,948 in depreciation expense associated with Land and Land Rights (Exh. ES-REVREQ-3, WP 25 (Rev. 4)).[93] The Department has consistently found that the purpose of depreciation is to recover the cost of a capital investment in order to replace a retired asset, and, therefore, there is no need to depreciate an asset that will not be retired. D.P.U. 93-60, at 188. See Berkshire Gas Company, D.P.U. 19580, at 16 (1978). Accordingly, the Department does not permit depreciation of land, land rights, or rights-of-way. D.T.E. 03-40, at 295; D.P.U. 93-60, at 188-189; D.P.U. 92-111, at 122; D.P.U. 19580, at 16; Western Massachusetts Electric Company, D.P.U. 18252, at 12 (1975). In the instant proceeding the Company does not provide a compelling argument to deviate from longstanding Department precedent, but simply presents a definition of "depreciation" from the Uniform System of Accounts (Exh. DPU 16-3). Therefore, the Department rejects the inclusion of $177,948 in depreciation expense associated with Land and Land Rights. Accordingly, we reduce NSTAR Electric's proposed depreciation expense by $177,948.

[93] $177,948 represents the sum of depreciation expense associated with Account 340.00 ($140,680), Account 360.00 ($37,229), and Account 389.00 ($39) (Exh. ES-REVREQ-3, WP 25 (Rev. 4)).

e. Conclusion

The Department has reviewed NSTAR Electric's depreciation study and supporting workpapers, and we find that the Company properly supported the proposed service lives and survivor curves (Exhs. ES-JJS-1; ES-JJS-2; ES-JJS-3; DPU 8-1; DPU 8-2, Att.; DPU 8-6, Att.). Based on the analysis above, the Department finds it appropriate to reduce the Company's proposed depreciation expense by $27,087,735, for a rate-year depreciation expense of $197,606,240 (see Exh. ES-REVREQ-3, WP 25 (Rev. 4)).

C. Insurance Expense

1. Introduction

During the test year, NSTAR Electric booked $4,035,454 in insurance expense and injuries and damages expense (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). The Company proposes to increase its test-year insurance expense by $2,171,572, resulting in a proposed insurance expense of $6,207,026 (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). In particular, during the test year, the Company booked $357,088 in Directors and Officers liability insurance ("D&O liability insurance") coverage expense (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). The Company proposes to increase D&O liability insurance expense by $194,489, resulting in a proposed D&O liability insurance expense of $551,578 (Exh. ES-REVREQ-2, Sch. 15 (Rev. 4)). Further, the Company did not include in its proposed insurance expense credits from its liability insurance carriers such as Nuclear Electric Insurance Limited ("NEIL") and Energy Insurance Mutual ("EIM") (Exhs. AG 8-45; AG 11-13).

2. Positions of the Parties

a. Attorney General

The Attorney General raises two issues with respect to the Company's insurance expense. First, the Attorney General argues that the Company should not be allowed to recover the full amount of D&O liability insurance coverage expense (Attorney General Brief at 123-125). Second, the Attorney General argues that the Company failed to reflect future NEIL and EIM credits in its rate year (Attorney General Brief at 126-127, citing Exhs. AG-LA-1, at 28-30; AG 8-45; AG 11-13).

Regarding the D&O liability insurance coverage expense, the Attorney General claims that the cost of these policies should not be fully borne by the ratepayers because the majority of the benefits resulting from D&O liability insurance coverage, which protects the Company's officers and directors from lawsuits arising from their own decisions, accrue to the Company and its shareholders (Attorney General Brief at 123). The Attorney General contends that the burden rests with the Company to demonstrate that ratepayers will receive measurable benefits in exchange for the costs of its D&O liability insurance coverage, and that the Company failed to make such a showing (Attorney General Brief at 123, citing Town of Hingham v. Department of Telecommunications and Energy, 433 Mass. 198, 213-214 (2001), citing Metropolitan District Commission, 352 Mass. 18, 24; Wannacomet Water Company v. Department of Public Utilities, 346 Mass. 453, 463 (1963); D.T.E. 99-118, at 7 n.5).

The Attorney General, however, recognizes that the D&O liability insurance policies may assist the Company in attracting higher-quality personnel (Attorney General Brief at 124, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9-10; Western Massachusetts Electric Company, D.P.U. 86-280-A, at 92 (1987)). Thus, the Attorney General argues that, despite the Company's failure to meet its burden of proof, shareholders and ratepayers should share the cost of these insurance expenses (Attorney General Brief at 124, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9-10; D.P.U. 86-280-A, at 92). Specifically, the Attorney General recommends that shareholders bear 75 percent, while ratepayers bear 25 percent, of the allocated D&O liability insurance coverage costs (Attorney General Brief at 124). The Attorney General notes that her recommendation is consistent with rulings by the Connecticut Public Utilities Regulatory Authority ("CT PURA") and other public utilities commissions (Attorney General Brief at 124, citing United Illuminating Company, CT PURA Docket No. 16-06-04, at 36 (2016); Ni Florida, LLC, FL PSC Docket No. 160030-WS, Order No. PSC-16-0525-PAA-WS, at 8 (2016); Connecticut Natural Gas Corporation, CT PURA Docket No.13-06-08, at 27 (2014); Entergy Arkansas, Inc., Arkansas PSC Docket No. 06-101-U, Order No. 10, at 70, (2007); Centerpoint Energy Resources Corp., Arkansas PSC Docket No. 04-121-U, Order No. 16, at 40 (2005); Southwest Gas Corporation, CPUC Application 02-02-012, Decision 04-03-034, at 34-35 (2004)). Therefore, the Attorney General recommends reducing the Company's proposed cost of service by $335,135 to represent a 75/25 sharing of these costs between shareholders and ratepayers, respectively (Attorney General Brief at 124-125, citing Exh. AG-LA-2, Sch. 4).[94]

Regarding the NEIL and EIM insurance credits, the Attorney General argues that the Company failed to reflect future credits in its rate year (Attorney General Brief at 126-127, citing Exhs. AG-LA-1, at 28-30; AG 8-45; AG 11-13). The Attorney General posits that while the NEIL and EIM credits are not guaranteed to occur, it is very likely that they will occur in the future based on the Company's insurance historical records (Company Brief at 126-127, citing Exhs. AG-LA-Surrebuttal-1, at 8; ES-RR/CPP/Comp-Rebuttal, at 26). The Attorney General asserts that the historical record shows that the Company has received NEIL and EIM insurance credits from 2017 through 2021, and there is no reason to assume that these credits will not occur in the future (Attorney General Brief at 127, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 26). Further, she argues that the Company will reap a financial windfall if the Company is allowed to keep these credits to the detriment of ratepayers (Attorney General Brief at 126-127, citing Exh. AG-LA-Surrebuttal-1, at 8). Therefore, the Attorney General argues that it is appropriate and important to include these credits as part of the Company's pro forma rate-year adjustment (Attorney General Brief at 127). Because the amounts of these credits fluctuate over time, the Attorney General recommends that the Company include a five-year average of credits in the pro forma

94 The Attorney General's proposed adjustment appears to be based on the Company's initial proposed test-year pro forma amount of D&O liability insurance expense, and the not the final amount proposed for recovery (Exhs. ES-REVREQ-2, Sch. 15; ES-REVREQ-2, Sch. 15 (Rev. 4)).

test-year amount (Attorney General Brief at 126-128, citing Exhs. AG-LA-2, Schs. 8, 9; AG 1-61, Att. I (Supp. 1)). Thus, the Attorney General asserts that the Department should reduce NSTAR Electric's proposed insurance expense by $50,575 and $449,835 to reflect NEIL and EIM insurance credits, respectively (Attorney General Brief at 126-128, citing Exhs. AG-LA-2, Schs. 8, 9; AG 1-61, Att. I (Supp. 1)).

b. Company

NSTAR Electric asserts that the Attorney General's arguments and conclusions regarding the D&O liability insurance expense are flawed, against recent Department precedent, and should be disregarded (Company Brief at 179-180, citing D.P.U. 20-120, at 302-304). The Company contends that it has taken steps to control costs associated with this insurance coverage, which is a direct benefit to customers (Company Brief at 180-181, citing Exhs. ES-REVREQ-1, at 87-90; ES-RR/CPP/Comp-Rebuttal-1, at 8; DPU 15-8; DPU 15-10; DPU 55-3; AG 1-61 & Supp.; AG 1-63 & Supp.; AG 8-18). Further, the Company claims that the primary purpose of the D&O liability insurance coverage is not to cover bad faith actions of its directors and officers (Company Brief at 181, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 9; DPU 55-3). Instead, NSTAR Electric asserts that D&O liability insurance coverage protects its management should they be personally exposed to liability claims for the business decisions and actions they make while operating the Company, thus enabling its leadership to make business decisions confidently without the fear of personal financial loss (Company Brief at 181, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9).

NSTAR Electric also contends that D&O liability insurance coverage benefits customers by ensuring that the Company is able to attract and retain skilled, experienced officers and trustees with long-term ties to the electric distribution industry who use their specialized areas of knowledge and expertise to provide safe and reliable service to customers (Company Brief at 181-182, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 9-10). Finally, NSTAR Electric argues that the Attorney General's recommended cost sharing of D&O liability insurance expenses is arbitrary and unsupported by any analysis and, therefore, should be rejected (Company Brief at 182 & n.59, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 8 n.2).

Regarding the NEIL and EIM insurance credits, NSTAR Electric argues that the Department should reject the Attorney General's recommendation because there is no guarantee that these credit distributions, prior years' distribution notwithstanding, will occur in the future (Company Brief at 182-183). In support of its position, the Company contends that it is unknown whether any NEIL and EIM insurance credit distributions will occur in the future and, therefore, the Attorney General's proposal is unmeasurable (Company Brief at 183). Further, the Company claims that it is inappropriate to utilize the five-year average of credit distributions because the annual distributions tend to fluctuate significantly (Company Brief at 183).

NSTAR Electric also argues that, adhering to the Department's regulatory principles, it would not propose to include speculative costs in the revenue requirement that do not pass the Department's known and measurable standard (Company Brief at 183). Thus, the

Company argues that any reduction to the Company's insurance expense should not be based on speculation, and therefore, the Department should reject the Attorney General's recommendation (Company Brief at 182-183).

3. Analysis and Findings

Rates are designed to allow for recovery of a representative level of a company's revenues and expense based on a historic test year adjusted for known and measurable changes. D.P.U. 10-55, at 274; Bay State Gas Company, D.P.U. 09-30, at 218 (2009); D.T.E. 02-24/25, at 161; D.P.U. 92-250, at 106. The Department will include the most current cost of liability and property insurance, based on a signed agreement, as a reasonable cost of service. D.P.U. 10-55, at 276; 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). The Department requires companies to provide evidence that they undertook reasonable measures to control property and liability insurance expenses. New England Gas Company, D.P.U. 08-35, at 119-120 (2009); D.T.E. 05-27, at 133-134; D.T.E. 03-40, at 184-185.

As noted above, the Attorney General contends that the Company should not be allowed to fully recover D&O liability insurance expense, and instead should share these costs with ratepayers (Attorney General Brief at 123-125). We disagree. In evaluating the Company's D&O liability insurance coverage, the Department considers whether the primary purpose of the policy is to cover bad faith actions and whether ratepayers receive measurable benefits. D.P.U. 20-120, at 302; D.P.U. 87-260, at 72-73; Commonwealth Gas Company, D.P.U. 87-122, at 51, 53-54 (1987); D.P.U. 87-59, at 41-42. In determining ratepayer benefits, the Department considers whether ratepayers would otherwise be required to pay for damages and legal fees arising out of such suits brought against the Company's directors and officers in the event the Company did not have such insurance. D.P.U. 20-120, at 302-303; D.P.U. 87-260, at 73. The record in this case demonstrates that the purpose of the Company's D&O liability insurance policy is to protect its directors and officers should they be personally exposed to liability claims for the business decisions and actions they make while employed by the Company or serving as a trustee, and to protect the personal assets of trustees and officers in a related lawsuit (Exh. DPU 55-3).

The record does not support a finding that the primary purpose of the D&O liability insurance policy is to protect the utility against bad faith actions of its directors and officers. In fact, such actions are expressly excluded by the policy (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 8-9; DPU 55-3 & Att.).[95] Thus, the Department finds that coverage by the D&O liability insurance policy primarily involves actions where the costs could be included in the Company's cost of service absent D&O liability insurance and, as such, the policy offers ratepayer benefits. D.P.U. 20-120, at 303. As such, we find that the costs associated with the Company's D&O liability insurance coverage are properly included in rates. D.P.U. 20-120, at 303-304; D.P.U. 87-260, at 73; D.P.U. 87-122,

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95 For instance, the policy excludes claims in the event that a director or officer: (1) used their position to gain personal profit, financial advantage, or remuneration to which they were not entitled; or (2) committed a deliberately fraudulent or criminal act or omission or any intentional violation of any law, statute, or regulation (Exh. DPU 55-3, Att.).

at 53-54; D.P.U. 87-59, at 41-42. Based on these findings, we need not address the merits of the Attorney General's recommended cost sharing approach.

Regarding the NEIL and EIM insurance credits, the record shows that NEIL made policy surplus distributions or insurance credits during the test year and in each of the prior five years (Exhs. AG 8-45; AG 1-61, Att. (e) (Supp. 1)). Likewise, EIM made similar policy surplus distributions during the test year and in each of the prior five years (Exhs. AG 11-13; AG 1-61, Att. (e) (Supp. 1)). Given this consistent history of credit receipts from NEIL and EIM, we are not persuaded by the Company's argument that there is no guarantee that these surplus distributions will occur in the future, and, therefore, are not known and measurable. D.P.U. 17-05, at 246-246. Further, the Department has found that EIM's policy surplus distributions are analogous to those made by NEIL. See D.P.U. 87-260, at 26-36. As a mutual non-profit carrier, NEIL makes policyholder distributions to recognize a return of a portion of the policy's surplus. The Department has required participants to credit policyholder distributions and other adjustments to customers in a manner approved by the Department. New England Power Company/Montaup Electric Company, D.P.U. 1251, at 10 (1983); Western Massachusetts Electric Company, D.P.U. 990-A at 10 (1982); D.P.U. 990, at 4; Western Massachusetts Electric Company, D.P.U. 147-B at 2-3 (1981); Boston Edison Company, D.P.U. 376-A at 2 (1981); D.P.U. 376, at 15-16. The Department has historically treated such credits as an offset against the current NEIL premium for ratemaking purposes because "policyholder distribution is a known and measurable change that should be included as an offset to the

Company's current NEIL premiums." D.P.U. 87-260, at 38-39.[96] Consistent with the treatment of NEIL surplus distributions in prior cases, the Department finds that, for the reasons explain above, it is also appropriate to adjust the Company's test year pro-forma cost of service to recognize the refund of the insurance proceeds from EIM, as well. D.P.U. 17-05, at 246.

Between 2017 and 2021, NEIL credits per year have ranged from a low of $4,472 in 2017 to a high of $105,590 in 2020, and EIM credits per year have ranged from a low of $217,583 in 2017 to a high of $767,872 in 2019 (Exh. AG-LA-2, Schs. 9 & 10). Thus, the test-year level of NEIL and EIM credits are not necessarily representative. Therefore, the Department finds that it is appropriate to normalize test-year NEIL and EIM credits by applying a five-year average to determine a representative level to be included in rates. See D.P.U. 09-39, at 149. Normalization is not intended to ensure dollar-for-dollar recovery of a particular expense or credit; rather it is intended to include in the cost of service as a representative annual level. 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.

Based on the above considerations, the Department will adjust the Company's cost of service. In this regard, the Department accepts the Attorney General's calculation of the five-year credit averages, based on information provided by the Company (Exhs. AG-LA-2,

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96 This ratemaking treatment is similar in concept to patronage refunds associated with CoBank, a lending institution that focuses on water systems, where the refunds serve to reduce the effective cost of the loan. Whitinsville Water Company, D.P.U. 08-33, at 14 (2008).

Schs. 8 and 9; AG 1-61, Att. (e) (Supp. 1)). Accordingly, the Department reduces NSTAR Electric's proposed cost of service by $500,410 ($50,575 + $449,835) (Exhs. AG-LA-2, Schs. 8 and 9; AG 1-61, Att. (e) (Supp. 1)).

The Department has reviewed NSTAR Electric's remaining insurance policies and supporting documentation. We find that the test-year insurance costs were reasonable, and the insurance expense premiums and proposed adjustments are based on actual policy rates and are thus known and measurable (Exhs. ES-REVREQ-1, at 88-92; ES-RR/CPP/Comp-Rebuttal-1, at 34-36; AG-DJE-1, at 9-12; AG-DJE-Surrebuttal-1, at 5-7; ES-REVREQ-2, Sch. 15 (Rev. 4); DPU 15-7, DPU 15-10; DPU 15-11; DPU 15-13, Supp. & Atts.; DPU 69-11 & Atts.; AG 1-61 & Atts. & Supps.; AG 4-19 & Att.; Tr. 1, at 145-146; RR-DPU-4 & Atts.; RR-AG-3). Further, the Department finds that NSTAR Electric has taken reasonable measures to control the costs of its insurance expense (Exh. DPU 15-8). Thus, with the exception of the adjustments set forth above, the Department accepts the Company's proposed insurance expense.

D. Board of Director Expenses

1. Introduction

Eversource Energy is governed by an eleven-member board of trustees, of whom ten are independent and one is a member of management (Exh. AG 1-2, Att. (5)(e) at 11). Each independent trustee receives an annual base retainer of $115,000, with additional amounts for serving as lead trustee and committee chairs, along with $160,000 in restricted stock units ("RSUs") (Exh. AG 1-2, Att. (5)(e) at 38). NSTAR Electric itself has a board of directors consisting of five Company officers who receive no additional compensation for their director responsibilities (Exhs. DPU 52-2; AG 1-2, Att. (6)(e) at 12 (Supp. 1)).[97] During the test year, the Company booked $930,151 in board fees and meeting costs to its distribution operations (Exhs. DPU 52-2; AG 8-4, Att.; AG 21-7, Att.).[98] These costs include the Company's allocated portion of cash retainers and RSUs paid to the independent members of Eversource Energy's board of trustees[99] (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 5; DPU 52-2; AG 1-2, Att. (5)(e) at 38; AG 21-7, Att.; Tr. 6, at 642).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department has made it clear that for costs to be recovered from ratepayers, a company must demonstrate that there is a link between the costs and ratepayer benefits (Attorney General Brief at 121, citing D.P.U. 20-120, at 224; D.P.U. 93-60, at 201; D.P.U. 92-111, at 127). The Attorney General contends that while

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97 For purposes of this Order, the Department uses "board of trustees" when referring to Eversource Energy's governing body, "board of directors" when referring to the Company's own governing board, and "board" when referring to both the board of trustees and board of directors.

98 While the Company did not propose an explicit adjustment to its test-year board expenses, the Company's proposed inflation allowance incorporates an increase to these expenses of $138,795, representing inflation of 14.909 percent from the midpoint of the test year to the midpoint of the rate year (see Exhs. ES-REVREQ-3 WP 24 (Rev. 4); AG 8-4, Att.).

99 The Company is only seeking rate recovery of trustee retainers and RSUs, and no other expenses trustees may incur in their duties such as travel expenses (Exh. AG 21-7, Att.; Tr. 6, at 642).

the existence of the Company's board of trustees logically produces some tangential benefits to ratepayers, the Company's shareholders are the major beneficiaries associated with the proposed board fees and associated meeting costs (Attorney General Brief at 121-122, citing Exhs. AG-LA-1, at 11-12; ES-RR/CPP/Comp-Rebuttal-1, at 6).

The Attorney General argues that to better reflect the balance of benefits arising from a board of trustees between the Company and ratepayers, the Department should disallow 75 percent of board fees and meeting costs, resulting in what she calculates as a reduction of $751,267 (i.e., the inflation-adjusted pro forma expense of $1,001,689 x 75 percent) (Attorney General Brief at 122, citing Exhs. AG-LA-1, at 12; AG-LA-2, Sch. 2, Att.).[100] The Attorney General asserts that this ratemaking treatment is consistent with rulings from other jurisdictions, such as in Connecticut, where the CT PURA has allocated 75 percent of board of director costs to shareholders (Attorney General Brief at 122, citing Connecticut Water Company, CT PURA Docket No. 20-12-30, at 12-14 (2021); United Illuminating Company, CT PURA Docket No. 13-01-19, at 73 (2013)).

b. Company

NSTAR Electric argues that to recover board fees in cost of service, the Department requires a company to demonstrate a link between those fees and customer benefits (Company Brief at 184, citing D.P.U. 20-120, at 329). The Company challenges what it considers to be the Attorney General's attempt to create a new standard for recovery of board

100 The Attorney General's calculations are based on the Company's initially-proposed inflation factor of 7.691 percent (Exhs. AG-LA-2; AG 8-4, Att.).

fees based on a requirement that ratepayers must be the majority or sole beneficiaries of these expenditures (Company Brief at 184).

The Company argues that the Attorney General has mischaracterized the customer benefits associated with board fees (Company Brief at 184). While NSTAR Electric acknowledges that Eversource Energy's board of trustees is tasked with representing shareholder interests, the Company contends that the Attorney General fails to recognize that actions taken to meet the board's obligations to shareholders also directly, and not tangentially, benefit customers (Company Brief at 184, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 6). NSTAR Electric points to the organization of the board of trustees and various standing committees, as well as Eversource Energy's shift in accordance with nationwide trends from a per-meeting fee structure to providing a cash retainer and stock award in the form of RSUs (Company Brief at 185, citing Exhs. AG 1-2, Att. (5)(e) at 22-28; AG 21-7; Tr. 3, at 284-287; Tr. 6, at 637).[101] The Company contends that the board's organization and compensation structures ensure that board members have a stake in Eversource Energy (and by extension the Company), take a hands-on approach in executing their duties as board members, and are actively involved in managing the direction of the Company (Company Brief at 185-186, citing Tr. 7, at 639-640). NSTAR Electric also maintains that in protecting shareholder interests, the board of trustees ensures that the

101 The Company relies on a national benchmark in setting trustee compensation, including a review of peer utilities, and contends that it targets the median level (Company Brief at 186, citing Tr. 7, at 637-640).

Company's assets, including those used to provide safe and reliable service to customers, are in good working order, as well as demonstrates to the financial markets and prospective shareholders that the Company is a solid and attractive financial investment (Company Brief at 184-185, citing Exh. ES-RR/CCP/Comp-Rebuttal-1, at 6). The Company argues that by attracting new shareholders, the board of trustees ensures that the Company benefits from a revenue stream that is used to fund capital projects that provide safe and reliable service to customers (Company Brief at 185, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 6).

NSTAR Electric goes on to argue that even if there is no connection between board fees and benefits to customers, the Attorney General has failed to provide any analysis to support her recommended 75 percent disallowance beyond a brief reference to a similar conclusion by the CT PURA (Company Brief at 186, citing Exh. AG-LA-1, at 13-14 (Rev.)). The Company contends that a review of the PURA orders relied upon by the Attorney General demonstrates that the CT PURA's decisions were not based on any analysis, and that the Attorney General's recommendation is based on an arbitrary determination of costs and benefits (Company Brief at 186).

3. Analysis and Findings

The Department recognizes that a company incurs certain costs related to the operations of its board of directors, such as director fees and other expenses. Aquarion Company/Aquarion Water Company of Massachusetts/New England Service Company/Mountain Water Systems/Colonial Water Company, D.P.U. 21-54, at 26 (2021); Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 88-92 (2009); D.T.E. 03-40, at 206-207; D.P.U. 92-111, at 147-148. While the Attorney General does not oppose the recovery of expenses related to the board on a per se basis, she proposes a sharing of these costs between the Company and its ratepayers on the basis of her benefits evaluation (Exh. AG-LA-1, at 13-14 (Rev.)).

A board of trustees or directors does not exist merely to satisfy legal governance requirements. Rather, it contributes to and shapes a company's culture, strategic focus, and financial performance, all of which are essential elements for any organization. While it is certainly true that neither Eversource Energy's board of trustees nor the Company's own board of directors are elected by ratepayers, the fiduciary duties of a regulated utility's governing body extend well beyond interests of shareholders. Specifically, a regulated utility is obligated to act in the best interest of ratepayers as part of that company's public service obligation to provide safe, reliable, and least-cost service. See D.P.U. 10-70, at 234 n.125; D.P.U. 07-50, at 5; D.P.U. 94-158, at 3; Boston Edison Company, D.P.U. 94-49, at 115-116 (1995); Boston Edison Company, D.P.U. 86-71, at 15-16 (1986). Consequently, decisions made by a utility's management and governing body cannot, and must not, prioritize shareholder interests over those of ratepayers. See Mergers and Acquisitions, D.P.U. 93-167-A at 22-23 (1994); Bay State Gas Company, D.P.U. 90-40, at 9-11 (1990).[102] The Department also notes that, unlike business organizations whose directors are chosen on

[102] Utilities that fail to recognize this fundamental principle do so at their own peril. D.P.U. 85-266-A/85-271-A at 6-15.

the basis of the prestige they may provide to the enterprise,[103] Eversource Energy's board of trustees actively participates in the operations of Eversource Energy and its subsidiaries both collectively and through their active participation in various committees (Exh. AG 1-2, Att. (5)(e) at 22-28; Tr. 3, at 284-287; Tr. 6, at 637-640). Given the distinct public service obligations of a regulated utility's board of trustees or directors and the active participation of Eversource Energy's board of trustees in its operations, the record does not support a finding that the primary purpose of the board of trustees is to serve the interests of Eversource Energy's shareholders.[104] Based on these findings, we need not address the merits of the Attorney General's proposed allocation method.

Based on the foregoing analysis, the Department concludes that Eversource Energy's board of trustee activities benefit ratepayers.[105] Accordingly, the Department accepts

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103 As a case in point, the now-defunct blood testing equipment manufacturer Theranos had a board of directors consisting of former cabinet members, congressmen, and military officials. While these directors may have sterling reputations in their respective fields, they do not appear to have been sufficiently involved in Theranos' medical technology business to engage in effective oversight.

104 To assume otherwise sets the entire concept of utility regulation back to the days of Framingham Gas, Fuel, and Power Company, a "notoriously slovenly and corrupt affair" where one of the last corporate acts of previous management, at the onset of an investigation by the Board of Gas and Electric Light Commissioners, was to "lose" their entire body of records. Manufactured Gas Plant Remediation: A Case Study, Allen W. Hatheway and Thomas B. Speight, CRC Press (2018) at 381.

105 The Department reminds Eversource Energy and the board of trustees of the importance of keeping customer benefits in mind during this upcoming winter season of anticipated high utility prices. While we recognize that Eversource Energy has little control over commodity prices, it does control other aspects of utility operations, such as customer shut-offs and arrearage management. We expect Eversource Energy

NSTAR Electric's proposal to include the Company's share of expenses associated with Eversource Energy's board of trustees in the Company's cost of service.

E. Dues and Memberships

1. Introduction

NSTAR Electric maintains memberships in various industry and non-industry trade associations and organizations (Exhs. ES-REVREQ-1, at 70; ES-REVREQ-3, WP 12 (Rev. 4); AG 8-19, Att.). The Company refers to "industry" memberships as specific only to the utility industry and "non-industry" memberships as everything else (i.e., not specific to the utility industry) (Exh. DPU 53-1). NSTAR Electric proposes $442,380 for industry dues expense and $359,967 in non-industry dues expense, for a total test year pro forma amount of $802,347 in dues and memberships expense (Exhs. ES-REVREQ-2, Sch. 12 (Rev. 4); ES-REVREQ-3, WP 12 (Rev. 4); DPU 53-2, Att.).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should not allow the recovery of certain non-industry dues and membership expenses because the Company has not demonstrated a clear link between those costs and ratepayer benefits (Attorney General Brief at 128-130; Attorney General Reply Brief at 39). The Attorney General claims that for the majority of the non-industry organizations for which the Company seeks to recover dues, it

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and the board, to take those necessary actions to protect ratepayers during the challenging winter season.

has offered only generalized ratepayer benefits without support for its assertions, and therefore, these costs should not be recovered from ratepayers (Attorney General Brief at 128-129, citing Exhs. AG-LA-1, at 19; DPU 15-1).

The Attorney General also argues that the Company, on brief, provides additional explanations and cites to information that it had not provided as record evidence in this proceeding, including describing organizations such as the International Energy Credit Association and ORC HSE Strategies, LLC, and citing to five organizations' websites (Attorney General Reply Brief at 39, citing Company Brief at 164-165). According to the Attorney General, NSTAR Electric bears the burden of demonstrating the link between the dues for which it seeks cost recovery and ratepayer benefits, and the Company's citing to this additional information as information that the Attorney General should have considered attempts to shift that burden (Attorney General Reply Brief at 39). The Attorney General also maintains that Company's attempt to shift the burden proves that the Company failed to meet its burden for cost recovery (Attorney General Reply Brief at 39).

Further, the Attorney General disputes the Company's inclusion of two entries for the same organization, i.e., Associated Industries of Massachusetts ("AIM") (Attorney General Brief at 129 & n.98). The Attorney General maintains that the double entry is a result of the Company paying dues for two calendar years in the test year, which is not a representative amount for this expense in a given year; therefore, one of the entries should be excluded from the revenue requirement (Attorney General Brief at 129 & n.98, citing Exh. DPU 53-2; RR-AG-11). Based on the above arguments, the Attorney General recommends a disallowance of $347,854 in non-industry dues expense as well as one of the AIM entries (Attorney General Brief at 129; Attorney General Reply Brief at 39).[106]

b. Company

NSTAR Electric argues that the Department should reject the Attorney General's recommendation as it ignores record evidence that demonstrates the link between the various organizations and customer benefits (Company Brief at 163). Further, NSTAR Electric rejects the distinction between "industry" and "non-industry" dues and memberships, and the Company asserts that it belongs to these organizations because membership provides access to industry experts and professionals, insight, data, research, and information used to address emergent issues facing the industry and to identify and incorporate relevant information and best practices into the provision of safe and reliable service to its customers (Company Brief at 163-165, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 13-16; DPU 38-1; DPU 53-2; Tr. 5, at 494; Company Reply Brief at 45).

For example, NSTAR Electric contends that membership in organizations such as the Chambers of Commerce allows the Company to interact with its customers, learn about local issues impacting customers, and shape the way the Company services these customers; therefore, there is a direct link between membership and customer benefits (Company Brief

106 The Attorney General notes that its recommended disallowance excludes adjusted test-year amounts for four organizations (American Benefits Council, the Drug and Alcohol Testing Industry Association, the Electric Utility Industry Sustainable Supply Chain Alliance, and the Northeast Human Resources Association) that the Company discussed in the benefits section of its surrebuttal testimony (Attorney General Brief at 129-130, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 13-16; DPU 53-2, Att.).

at 164, citing Tr. 5, at 494). Moreover, NSTAR Electric maintains that memberships in other non-industry categories such as ORC HSE Strategies, LLC, provides the Company access to industry experts and helps it develop processes and procedures to identify and reduce or remove potential workplace hazards and to train employees for accident prevention and response (Company Brief at 165). The Company contends that workplace safety is a key component of the provision of safe and reliable service, which benefits customers (Company Brief at 165).

In response to the Attorney General's assertion that the Company provided new evidence to demonstrate that certain dues are appropriate for cost recovery, NSTAR Electric contends that each of the organizations referenced in its initial brief were included in the Company's responses to information requests in this proceeding (Company Reply Brief at 44, citing Exhs. DPU 38-1; DPU 53-2). NSTAR Electric asserts that by including these organizations in these responses, the Company determined that they met the Department's standard for recovery (i.e., there is a link between the dues and customer benefits) (Company Reply Brief at 44-45, citing D.P.U. 20-120, at 329; Bay State Gas Company, D.P.U. 92-111, at 127 (1992); Milford Water Company, D.P.U. 92-101, at 54 (1992); The Berkshire Gas Company, D.P.U. 90-121, at 151 (1990)). Further, according to the Company, the missions of these organizations and their connection to providing customers with safe and reliable service are objective facts that are capable of definitive verification and are readily available to the Department and the Attorney General (Company Reply Brief at 45 & n.7).

For all of the above reasons, NSTAR Electric claims that it met the Department's standard for inclusion of these costs, and the Department should reject the Attorney General's recommendations (Company Brief at 166, citing Exhs. ESRR/CPP/Comp-Rebuttal-1, at 13-16; AG 22-2; AG 38-1; DPU 15-1, DPU 53-1; Company Reply Brief at 45). Finally, the Company agrees with the Attorney General that the Department should remove one of the double entries associated with AIM, a reduction of $15,312 from its proposed cost of service (Company Brief at 165-166).

3. Analysis and Findings

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; D.P.U. 92-101, at 54; D.P.U. 90-121, at 151. In support of its position that the costs should be recoverable, the Company generally states that all of the organizations offer insight, expertise, industry data, publications, and best practices that the Company uses to provide safe and reliable service (Company Brief at 163-165, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 13-16; DPU 38-1; DPU 53-2; Tr. 5, at 494; Company Reply Brief at 45). The Department asked the Company to outline specific, direct customer benefits related to each of its non-industry dues and memberships, and the Company's response was in the form of brief, general explanations, noting vague benefits such as input to inform the Company's efforts to provide service to customers and the opportunity to meet with business customers to exchange ideas to facilitate the Company's service to customers (Exhs. DPU 15-1; DPU 53-1).[107] While the Department recognizes that some of these memberships may help provide insight to NSTAR Electric 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 these non-industry organizations and meaningful benefits to customers, or that these memberships are necessary to the provision of electric distribution service to customers.

Specifically, the Department finds that the Company sufficiently demonstrated direct and distinct benefits to ratepayers for four of the non-industry organizations for which it seeks to recover dues and membership costs – the American Benefits Council, the Drug and Alcohol Testing Industry Association, the Electric Utility Industry Sustainable Supply Chain Alliance ("EUISSCA"), and the Northeast Human Resources Association (e.g., the Company's membership in EUISSCA helps it to address supply chain issues) (Exh. ESRR/CCP/Comp-Rebuttal-1, at 13-16). On brief, the Company offers additional detailed explanations of benefits for other non-industry organizations, such as ORC HSE Strategies, LLC (Company Brief at 164-165; Company Reply Brief at 44-45). The evidentiary record, however, contains only the names of these organizations, and not detailed explanations (Exhs. ESRR/CCP/Comp-Rebuttal-1, at 13-16; DPU 15-1& Att.; DPU 38-1 &

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107 In contrast, the Company provided clear, specific, and detailed customer benefits related to each of its proposed industry dues and memberships (Exh. AG 38-1, at 1-6). For example, Eversource Energy's participation on the Advanced Energy Economy's Utility Advisory Committee fosters understanding of generation and storage solutions to incorporate into long term system planning and supports a clean energy future at the Company (Exh. AG 38-1, at 5).

Att.; DPU 53-1; DPU 53-2 & Att.; AG 8-19, Att.; AG 22-2; AG 38-1). 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. Simply listing the organizations in a response to an information request seeking substantive information does not satisfy that burden. Nor is it the Department's role to independently verify the nature of each organization and attempt to discern the link between their function and customer benefits.

Based on the foregoing considerations, the Department allows recovery of the costs associated with the four aforementioned organizations 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 American Benefits Council, the Drug and Alcohol Testing Industry Association, EUISSCA, and the Northeast Human Resources Association is $12,113 (Exh. ES-REVREQ-3, WP 12 (Rev. 4)). We disallow recovery of the costs associated with the remaining non-industry 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. 20-120, at 329-330. Finally, the Department allows recovery of NSTAR Electric's industry dues and memberships, with the exception of one of the double entries associated with the Company's AIM membership, a reduction of $15,312 (Exh. ES-REVREQ-3, WP 12 (Rev. 4); DPU 53-2, Att.; AG 38-1). Accordingly, the Department reduces the Company's proposed cost of service by $363,166 ($347,854 in disallowed non-industry dues + $15,312 in disallowed industry dues).

F. Caregiver Program

1. Introduction

During the test year, NSTAR Electric booked $85,432 for the Caregiver Program included in its proposed residual O&M expense (Exh. AG 8-10, Att.). Eversource Energy's operating companies implemented the Caregiver Program on July 1, 2019, in response to employee-requested support on storm days (RR-AG-14; Tr. 6, at 686).[108] Under this program, Eversource Energy makes quarterly payments of $51,000, or approximately $20 per employee, to the contractor Care.com for a total pool of 300 backup days available annually for employees (Tr. 6, at 681-682). The Company states that these backup days are available for care of an employee's dependents up to ten days per employee per year in the event of an emergency (Exh. AG 8-10). As part of this benefit, employees also receive a free membership to Care@Work to connect to a network of caregivers for dependent care (Exh. AG 8-10).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company failed to justify that the Caregiver Program costs are reasonable, prudently incurred, and benefit ratepayers (Attorney General

[108] Employees of NSTAR Electric and Eversource Energy have storm restoration support roles during emergency storm days (Tr. 6, at 683).

Brief at 130; Attorney General Reply Brief at 37, citing Fitchburg Gas and Electric Light Company, 375 Mass. 571, 582-583). She also contends that the Caregiver Program is not standard in the market (Attorney General Reply Brief at 37).

Further, the Attorney General argues that although the Company pays a single flat fee to provide the pool of 300 backup days to all employees, most employees do not use it (Attorney General Reply Brief at 37, citing Tr. 6, at 681). She asserts that the employees only used 18 days in 2019, 210 days in 2020, 90 days in 2021, and, as of July 15, 2022, 49 days in 2022 (Attorney General Reply Brief at 37, citing RR-AG-14). In particular, the Attorney General contends that the Company's employees only used a fraction of the backup days during the COVID-19 pandemic in 2020 (Attorney General Reply Brief at 37). She also claims that the flat fee is only the membership fee and does not cover the actual backup dependent care costs, which employees pay for themselves (Attorney General Reply Brief at 37-38, citing Tr. 6, at 685-686).

Moreover, the Attorney General argues that the Company has not provided documentation or evidence to support its claim that customers benefit from a stable workforce, which the Caregiver Program facilitates (Attorney General Brief at 130, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 12). The Attorney General asserts that because NSTAR Electric does not track the number of missed workdays or employees who have left their jobs due to dependent care issues, the Company failed to demonstrate the Caregiver Program provides any impact on employee productivity or employee retention (Attorney General Brief at 130, citing Tr. 6, at 686).

b. Company

The Company argues that the Caregiver Program benefits customers because it provides a safety net that ensures trained employees can perform their work duties to provide safe and reliable service to customers (Company Brief at 173). According to the Company, a recent childcare report issued by the Massachusetts Taxpayer Foundation determined that, due to inadequate childcare, individuals and families lose $1.7 billion in wages from missing work or reducing their hours; employers lose $812 million due to lower productivity and turnover/replacement costs; and Massachusetts forgoes $188 million in tax revenues due to lower earnings and lost wages (Company Brief at 173, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 11). NSTAR Electric asserts that the Caregiver Program also benefits customers by facilitating a stable workforce, as the program reduces the number of day employees miss from work when primary care is temporarily unavailable (Company Brief at 173-174). Further, NSTAR Electric contends that 31 percent of large employers offered subsidized caregiving programs like the Company's Caregiver Program to their employees in 2021, and between 25 and 30 percent of the utility companies offer subsidized childcare to their employees (Company Brief at 173, citing Tr. 6, at 695; Company Reply Brief at 41).

The Company also rejects the Attorney General's contention that most employees are not using the Caregiver Program. According to the Company, employees use the Caregiver Program in the event of emergencies to ensure that they are available to report to storm restoration support roles during ERP events (Company Reply Brief at 41, 42, citing Tr. 6, at 683). Finally, NSTAR Electric contends that it has met its burden of proof and burden of production in demonstrating that the costs associated with the Caregiver Program benefit customers, are reasonable, and were prudently incurred (Company Reply Brief at 43).

3. Analysis and Findings

The Company bears the burden of demonstrating that proposed costs benefit Massachusetts ratepayers, are reasonable, and were prudently incurred. D.P.U. 11-01/D.P.U. 11-02, at 323; D.T.E. 03-40, at 140-141; D.P.U. 1699, at 13. This standard applies whether the expenses were incurred at the parent level or at the service company level. The Department has previously stated that the Department may consider allowing Caregiver Program costs if the Company provides convincing evidence substantiating the relationship between the benefit program and ratepayer benefits, and that these benefits are common industry practice and necessary for the Company to stay competitive in attracting skilled employees. D.P.U. 20-120, at 225.

The Company represents that it implemented the Caregiver Program in response its employees' need for dependent care during emergency storm response (Tr. 6, at 683, 686, 696). Most of Eversource Energy employees have a secondary responsibility in storm restoration support roles, in addition to their normal role, during a storm event, such as coordinating food and lodging for the storm restoration team (Tr. 6, at 683, 696). The frequency and severity of major storm events has increased noticeably since 2009, and such storms may arise on short notice when regular dependent care is unavailable (Tr. 6, at 696). Massachusetts Electric Company, Nantucket Electric Company, and NSTAR Electric

Company, D.P.U. 21-75/D.P.U. 21-76, at 22 (2021). The Department finds that by providing backup care during emergency storm response, the Caregiver Program creates stability in the workforce, and therefore provides benefits to ratepayers by enabling the Company to provide safe and reliable service to its customers. Regarding the availability of this benefit across the industry, the Company states that approximately 25 to 30 percent of utility companies offer subsidized childcare to their employees (Tr. 6, at 695). While this percentage may not rise to the level of common industry practice, in this instance, given the importance of providing a stable workforce during emergency storm response and the resulting benefits to customers, the Department allows the $85,432 of costs associated with the Caregiver Program in the Company's residual O&M.

G. Enterprise Information Technology Expense

1. Introduction

Enterprise IT expense represents charges billed to NSTAR Electric for ESC's investments in IT systems that support more than one of the Eversource Energy operating companies (Exh. ES-REVREQ-1, at 72). Enterprise IT projects that support more than one company are installed at the service company level to efficiently implement one integrated solution to be used on a shared basis and to efficiently charge the costs of shared infrastructure across multiple entities (Exh. ES-REVREQ-1, at 72-73). Accordingly, Enterprise IT projects are capitalized by ESC and charged to the operating companies as expense through the general service company overhead rate (Exhs. ES-REVREQ-1, at 53-54, 72-73, 79-80; DPU 48-1; DPU 48-5; AG 1-28 & Att. (c); AG 1-92). ESC's revenue requirement for the Enterprise IT projects is comprised of depreciation expense and a return on ESC's gross investment base less accumulated depreciation and ADIT (Exhs. ES-REVREQ-2, Sch. 14 (Rev. 4); ES-REVREQ-4, Sch. 5(b) (Rev. 3)). ESC allocates 32.44 percent of Enterprise IT costs to NSTAR Electric, which represents the Company's proportionate share of net income and gross plant assets (Exhs. ES-REVREQ-1, at 81; DPU 48-5). This percentage allocator is a total Company allocator that includes transmission; therefore, the Company applies an additional adjustment to remove the portion of the expense attributable to transmission (Exhs. ES-REVREQ-1, at 81; ES-REVREQ-2, Sch. 14 (Rev. 4)). Finally, because ESC employees perform both capital and expense functions for the Company related to the Enterprise IT projects, an ESC expense ratio of 64.05 percent is applied against the total cost for NSTAR Electric, with the remainder charged to capital or other balance sheet accounts and not included in the revenue requirement (Exhs. ES-REVREQ-1, at 81; ES-REVREQ-2, Sch. 14 (Rev. 4); ES-REVREQ-4, Sch. 5(b) (Rev. 3)).

During the test year, the Company booked $33,020,432 in Enterprise IT projects expense (Exh. ES-REVREQ-2, Sch. 14). The Company initially proposed a pro forma increase in Enterprise IT expense of $10,869,443 based on the total estimated revenue requirement associated with: (1) expected changes in Enterprise IT expense through December 31, 2021; and (2) the post-test-year Oracle Utilities Analytics ("OUA")[109] and

[109] The Company explains that the OUA project will replace the current FocalPoint reporting systems (Exhs. ES-ADDITIONS-1, at 60-61; ES-REVREQ-1, at 75). The implementation of OUA will address outage reporting system limitations by providing

Network Management System ("NMS")[110] capital projects undertaken by ESC in 2022 (Exhs. ES-REVREQ-1, at 73-74; ES-REVREQ-2, Sch. 14). During the proceeding, the Company reduced its proposed Enterprise IT pro forma adjustment to $7,906,029 based on: (1) a revised calculation of ESC's return on the test-year and post-test-year investments to reflect NSTAR Electric's proposed weighted average cost of capital ("WACC") and (2) updates to Enterprise IT project expense for actual 2022 ESC plant activity for the OUA and NMS projects (Exh. ES-REVREQ-2, Sch. 14 (Rev. 1 through 3)). Thus, the Company proposes a total Enterprise IT expense of $40,926,462 (Exh. ES-REVREQ-2, Sch. 14 (Rev. 4)).

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a single, enterprise outage reporting system that is architected to integrate with ESC's enterprise outage management system to provide outage related data in near real-time through a robust, high performance outage reporting platform (Exhs. ES-ADDITIONS-1, at 61; ES-REVREQ-1, at 75-76; AG 12-43).

110 The Company explains that the NMS project will upgrade the current NMS system to the latest Oracle software version 2.4 in conjunction with the implementation of new server hardware that will enhance system performance and reliability to provide a modernized, technically current software/hardware platform that is fully vendor supported through 2023 (Exhs. ES-ADDITIONS-1, at 63; ES-REVREQ-1, at 77; AG 12-44). Additionally, four high business-value system enhancements, which include Training Simulator, Outage Mobile Application, Automated Single Outage No Light Closeout, and Automated Overlay Google Map Satellite Imagery, will be implemented as part of the NMS project to deliver significant new business capability that directly support and advance operational excellence across ESC (Exhs. ES-ADDITIONS-1, at 63; ES-REVREQ-1, at 77).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that NSTAR Electric failed to timely provide project closure reports to support its Enterprise IT expense, despite the Company's awareness of the Department's specific filing requirements (Attorney General Brief at 131-132, citing Exhs. ES-ADDITIONS-1, at 56-57; AG 15-21 through AG 15-25; D.P.U. 18-150, at 275). The Attorney General contends that the Company acknowledged the delay in providing the closing reports but claimed that all of the required documentation had been provided within six months of the initial filing (Attorney General Brief at 132, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 40).

The Attorney General also claims that there are deficiencies with the variance analyses provided by the Company (Attorney General Brief at 132). In particular, the Attorney General asserts that the Company's purported variance analyses contains estimates, revisions, actuals, and the variance amount, but provide no actual analytical detail such as the reason for the variance or which costs contributed to the variance (Attorney General Brief at 132, citing Exh. DPU 69-12, Att. (a); Tr. 1, at 28-30).

The Attorney General argues that NSTAR Electric's failure to provide timely documentation that substantively complies with the Department's filing standards left insufficient time to conduct a meaningful review of costs and raised doubt about the accuracy of the Company's filing (Attorney General Brief at 132-133). Although the Attorney General does not recommend a specific disallowance of costs, she contends that the Department should enforce its existing standards and institute and enforce strong administrative safeguards to prevent similar issues in the future, such as the automatic disallowance of costs for projects for which mandated documentation is not provided with a Company's initial filing (Attorney General Brief at 132-133, citing D.P.U. 18-150, at 274-275). The Attorney General also asserts that the Department should require the following information in variance analyses: (1) original estimates, (2) any updated estimates and the related causes, and (3) detailed explanations for both the causes and amounts of any variances, including proper identification of which costs caused the variance (Attorney General Brief at 133).

The Attorney General argues that, despite the Company's position to the contrary, her recommendations are appropriate as they only seek enforcement of the Department's existing standards (Attorney General Reply Brief at 39-40). Finally, the Attorney General rejects any notion that her recommendations would penalize the Company for circumstances beyond its control (Attorney General Reply Brief at 40). The Attorney General contends that the information required to be submitted with the initial filing includes basic, essential Company-generated and maintained project documentation, and the Department's standard allows for additional supporting documentation to be provided through discovery in a timely fashion no later than the close of discovery (Company Reply Brief at 40, citing D.P.U. 18-150, at 275).

b. Company

NSTAR Electric asserts that it will examine the issues experienced with document production in this proceeding to refine and improve its processes for future filings; however, the Company argues that the automatic disallowance of costs without a showing of imprudence as suggested by the Attorney General is inappropriate and should be rejected (Company Brief at 210). NSTAR Electric contends that the Attorney General's recommendation is impermissibly punitive and could ultimately penalize the Company for circumstances beyond its control, such as when a vendor fails to provide an invoice in a timely fashion for its inclusion in the initial filing (Company Brief at 210). In addition, NSTAR Electric argues that the Attorney General's automatic disallowance recommendation ignores the Department's criteria in D.P.U. 18-150 that requires the Company to produce documentation throughout the course of the discovery period (Company Brief at 210).

Regarding the sufficiency of the information produced in this proceeding, NSTAR Electric claims that it has provided all project documentation supporting its Enterprise IT projects from 2016 through 2021, including Project Authorization Forms and any supplements, approvals, and the appropriate variance analyses for these projects, consistent with the Company's Capital Authorization Policy (Company Brief at 211, citing Exhs. ES-ADDITIONS-11, Atts. (a) through (f); DPU 69-12, Att. (c); RR-AG-11).

Further, NSTAR Electric asserts that it has met the Department's standard for the inclusion of the post-test-year OUA and NMS projects (Company Brief at 209). Specifically, NSTAR Electric contends that both projects are in service and used and useful, the projects advanced the ESC IT strategy and long-term investment plan, project costs were prudently incurred, and no party argued that the costs associated with the projects were imprudent or contrary to the Company's Capital Authorization Policy (Company Brief at 209, citing

Exhs. DPU 48-1; DPU 69-12). In addition, NSTAR Electric claims that the costs were fairly allocated from ESC to the Company (Company Brief at 209, citing Exhs. ES-REVREQ-1, at 72-73, 79-80; DPU 48-1 & Att.; DPU 48-5; AG 1-28 & Att.(c); AG 1-92). While the Company acknowledges that there were delays in providing documentation regarding these projects, the Company maintains that it ultimately provided a comprehensive, consolidated version of the Enterprise IT project documentation during discovery to aid in review of these projects (Company Brief at 209, citing Exhs. ES-REVREQ/CPP/Comp-Rebuttal-1, at 40; DPU 69-12).

3. Standard of Review

The standard for the inclusion of IT expense is comprised of three elements.[111] First, the investments underlying the IT expense must be in service and used and useful. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Second, the underlying IT investments must be prudently incurred. D.P.U. 18-150, at 274, citing D.P.U. 95-118, at 42. Third, the underlying IT investments must be fairly allocated to the company, with an explanation of how the company and its ratepayers benefit from the investment. D.P.U. 18-150,

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[111] Historically, the Department reviewed a petitioning company's proposed IT expense under the standard of review for lease expense (i.e., reasonableness), as the affiliated service company included IT expense in its lease charges to the petitioning company. D.P.U. 18-150, at 273; D.P.U. 15-155, at 308; D.P.U. 09-39, at 159-159. In D.P.U. 18-150, the Department found that, in conjunction with the increasing importance of IT in business functions, the size and scope of IT investments had become more significant and that this trend likely would continue. D.P.U. 18-150, at 272-273 & n.125. Based on these considerations, the Department found that the lease expense standard of review was no longer sufficient to satisfy the burden of proof necessary for IT-related expense. D.P.U. 18-150, at 273.

at 274-275, citing Hingham Water Company, D.P.U. 88-170, at 21 (1989); Housatonic Water Works Company, D.P.U. 86-93, at 18 (1987); see also Milford Water Company, D.P.U. 12-86, at 11 (2013) (the Department must carefully scrutinize affiliate transactions because the exercise of control and the absence of arm's-length bargaining between affiliated companies can lead to "excessive charges for services, construction work, equipment and materials") (citations omitted); Public Utility Holding Company Act of 1935, P.L. No. 333, 49 Stat. 803, § 1(b)(2), (3) (1935) (Congress recognized concern with allocation of costs within public utility holding company as reason for legislative/regulatory control of holding companies where subsidiary company accounting practices and rates are affected); Report of the Special Commission on Control and Conduct of Public Utilities (1930 H. 1200), at 46 (March 1930) (consumers suffer from excessive charges by affiliates to operating companies). In addition, as part of their initial filings requesting new base distribution rates, petitioning companies must submit the following documentation for each service-company-allocated IT investment: (1) project sanctioning papers; (2) project closure reports; (3) variance analyses explaining the reasons for cost overruns and for demonstrating prudency; (4) project descriptions, including completed analyses enumerating ratepayer benefits and the investment's advancement of company IT strategy; and (5) the company's long-term investment plan. D.P.U. 18-150, at 275. Petitioning companies are also required to amend their initial filing to include documentation associated with post-test-year investments, if applicable. D.P.U. 18-150, at 275.

4. Analysis and Findings

The Department has reviewed the testimony and supporting documentation for the Company's test-year and post-test-year Enterprise IT investments, as well as updates provided during the proceeding, including initial and supplemental project authorization forms, project approvals, project costs, project closing reports, descriptions of ratepayer benefits, and variance analyses (Exhs. ES-REVREQ-1, at 72-73, 79-80; ES-ADDITIONS-1, at 52-65; ES-RR/CPP/Comp-Rebuttal-1, at 39-43; ES-ADDITIONS-8A & Supp.; ES-ADDITIONS-8B & Supp.; ES-ADDITIONS-11; DPU 15-2; DPU 48-1 & Att.; DPU 48-5; DPU 69-5, Att. & Supp. 1; DPU 69-6, Att. & Supp.; DPU 69-12 & Atts. (a) through (f)[112]; AG 1-28 & Att. (c); AG 1-92; Tr. 1, at 21-39, 65-68; RR-AG-1). We find that the test-year and post-test-year Enterprise IT projects are in-service, used and useful, the costs were prudently incurred, and the Company provided a reasonable explanation of the benefits to ratepayers (Exhs. DPU 48-1; DPU 69-12, Atts. (a), (c, parts 1-21)). For example, customers benefit from the proposed Enterprise IT investments because the systems are necessary for the provision of electric service to customers and they are less expensive for any individual operating company, including NSTAR Electric, when the systems undertaken within a cost-sharing framework (e.g., undertaken by ESC on behalf of the

112 At the Company's request, Exh. DPU 69-12, Att. (a) replaces Exhs. ES-ADDITIONS-9 & Rev.; Exh. DPU 69-12, Att. (b) replaces Exhs. ES-ADDITIONS-9 (Supps. 1 and 2); and Exh. DPU 69-12, Att. (c), parts 1 through 28 replace Exhs. ES-ADDITIONS-10, ES-ADDITIONS-10A, and ES-ADDITIONS-10 (Supps. 1 and 2).

operating companies on a shared basis) (Exh. DPU 48-1). In addition, the Company's post-test-year OUA and NMS projects are in service, used and useful, and the costs of these projects were prudently incurred, with actual costs through June 30, 2022, being less than the estimated costs for these projects (Exhs. ES-ADDITIONS-8A & Supp; ES-ADDITIONS-8B & Supp.; DPU 69-5, Att. (Supp. 1); DPU 69-6, Att. (Supp. 1); DPU 69-12, Atts. (b), (c, parts 22-28); Tr. 1, at 30-31, 38).[113]

Further, we find that the test-year and post-test-year Enterprise IT project costs were fairly allocated to NSTAR Electric based on the Company's proportionate share of net income and gross plant assets (Exhs. ES-REVREQ-1, at 80-81; ES-REVREQ-2, Sch. 14 (Rev. 4); DPU 48-5; AG 1-28 & Att. (c); AG 1-92). The allocation is based on the Company's operations portfolio designation, which is largely asset driven and uses the referenced allocator (Exh. DPU 48-5). Lastly, the Company provided a summary of its IT long-term investment plan (Exh. DPU 48-1, Att.).

The Company acknowledges its challenges and delays in providing project documentation for Enterprise IT projects throughout this proceeding and concedes that it bears the burden to fully support its requests for cost recovery with appropriate

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113 The Company outlines numerous business and operational benefits associated with the implementation of the OUA and NMS systems (Exhs. ES-REVREQ-1, at 76, 78-79; ES-ADDITIONS-1, at 61-62, 63-64). Any potential savings resulting from these systems would be recognized in the future, and, therefore, they are not currently quantifiable or included in the cost of service (see Exh. AG 14-6). The Department expects NSTAR Electric to reflect potential future savings in the Company's next base distribution rate case.

documentation (Company Brief at 210). The Department recognizes that there are acceptable circumstances when not all required documentation may be available at the time of a company's initial filing. For example, as described above, two of NSTAR Electric's Enterprise IT projects in the instant proceeding were placed in service several months following its initial filing, and, therefore, the Company was unable to provide closing reports for these projects with the initial filing (Tr. 1, at 30-31, 38). Our standard for the inclusion of IT expense costs recognizes that petitioners are required to amend their initial filing to include documentation associated with post-test-year investments, if applicable. D.P.U. 18-150, at 275.

The Department notes, however, that while NSTAR Electric ultimately provided the required documentation to support the recovery of the costs associated with its Enterprise IT projects, the Company did not provide all the required documentation with its initial filing, was required to submit supplements and revisions to numerous exhibits, inadvertently omitted certain information from exhibits, and often requested multiple extensions of time to respond to information requests regarding Enterprise IT projects (see, e.g., Exhs. ES-ADDITIONS-8A & Supp.; ES-ADDITIONS-8B & Supp.; ES-ADDITIONS-9 & Rev., Supps.; ES-ADDITIONS-10 & Supps.; ES-ADDITIONS-10A; DPU 69-12 & Atts.). Further, the Company's need to develop a "roadmap" mid-proceeding to facilitate the Department's and intervenors' review of the Enterprise IT documentation highlights the Company's difficulties in providing complete information in a timely, organized manner (Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 40-41; DPU 69-12 & Atts.).

Despite the Company's shortcomings in providing the Enterprise IT projects supporting documentation, we find that the Attorney General and other parties nevertheless had sufficient opportunity to review the documentation, issue discovery, conduct meaningful cross-examination at the evidentiary hearings, and present any objections to cost recovery for Department consideration (see, e.g., Exhs. AG-LA-1, at 4-8; AG 14-5; AG 14-6; AG 4-18; AG 12-43; AG 12-44; AG 24-6, AG 24-7; Tr. 1, at 21-39, 65-68; RR-AG-1; Attorney General Brief at 131-133; Attorney General Reply Brief at 39-40). As such, in this instance, we will not disallow any test-year or post-test-year Enterprise IT investments. Further, we are not persuaded that additional directives are necessary for future filings, such as the automatic disallowance of costs recommended by the Attorney General.

The Department does, however, reaffirm our requirements related to IT project documentation and reminds companies that it is critical for complete and detailed IT-related investment documentation to be submitted in a timely fashion so that the Department and intervenors have sufficient time for review. Specifically, as part of initial filings requesting new base distribution rates, petitioning companies must submit the following documentation for each service company-allocated IT investment: (1) project sanctioning papers; (2) project closure reports; (3) variance analyses explaining the reasons for cost overruns and for demonstrating prudency; (4) project descriptions, including completed analyses enumerating ratepayer benefits and the investment's advancement of company IT strategy; and (5) the petitioning company's long-term investment plan. D.P.U. 18-150, at 275. Further, variance analyses must contain original estimates, any updated estimates, detailed explanations for both the causes and amounts of variances, and identification of which costs caused the variance. Petitioning companies can amend initial filings to include documentation associated with post-test-year investments, if applicable. All additional supporting documentation provided through discovery should be produced in a timely fashion and no later than at least one week prior to the close of discovery.

Finally, consistent with Department precedent, for the return component of the Company's Enterprise IT project expenses, the Department calculates the WACC using the capital structure and ROE approved in this Order. D.P.U. 20-120, at 293-294; D.P.U. 19-120, at 255-256; D.P.U. 18-150, at 270-271. Using the capital structure and ROE approved in this proceeding produces an overall WACC of 7.06 percent and a pre-tax WACC of 9.02 percent. Application of the Company's approved pre-tax WACC to ESC's allocation of Enterprise IT expense results in a decrease of $52,095 to the proposed rate year expense (see Exh. ES-REVREQ-2, Sch. 14, at 2 (Rev. 4)). Accordingly, the Department decreases the Company's proposed cost of service by $52,095 for an approved increase to Enterprise IT expense of $7,853,934.

H. Incremental COVID-19 Expenses

1. Introduction

In response to the COVID-19 pandemic, the Department allowed each gas and electric company to record, defer, and track their incremental pandemic-related response costs, subject to a final determination as to their appropriate ratemaking treatment. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order

Opening Investigation at 22-23 (December 31, 2020). Consistent with these rulings, Eversource Energy established affiliate-specific accounting work orders to identify and track incremental non-labor COVID-19 related expenses, such as costs associated with employee protection processes and equipment, facilities cleaning, maintaining the workforce at remote locations, certain telecommunication expenses, and other related costs (Exhs. DPU 3-1; DPU 19-4 & Att.; DPU 56-2).

As of December 31, 2020 (i.e., the end of the test year), NSTAR Electric had incurred total COVID-19-related expenses of $8,848,163, of which $7,907,079 was allocated to distribution operations (Exh. DPU 3-2, Att.). The Company also identified COVID-19-related cost savings of $379,940 that were allocated to distribution operations, producing a net COVID-19-related expense of $7,527,139 (Exhs. DPU 3-2; DPU 56-1).[114] Of the $7,909,079 in distribution-related expenses, the Company identified $4,675,470 as nonrecurring and thus eligible for deferral (Exhs. DPU 3-2; AG 1-34, Att. (h) at 7; AG 1-34, Att. (i) at 5; AG 21-1, Att.). The $7,909,079 in total distribution-related expenses, less $4,675,470 in deferrals, produced a total remaining COVID-19 expense allocated to distribution operations of $3,231,610 (Exhs. DPU 3-2; AG 21-1, Att.; DPU 56-1).

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[114] Cost savings represent expenses that had been avoided as the result of suspended work activities. D.P.U. 20-58-D/D.P.U. 20-91, Interim Order on Ratemaking Proposal and Vote and Order Opening Investigation at 15 (December 31, 2020). The Company's calculations were based on the $7,907,079 total distribution-related expense and did not factor in the $379,940 cost savings (see Exhs. DPU 3-2; DPU 56-1).

NSTAR Electric initially included $3,231,610 in COVID-19-related expenses in its proposed cost of service (Exhs. DPU 56-1; AG 13-2). During the proceeding, the Company revised its estimate of ongoing COVID-19 response costs from $3,231,610 to $988,000, based on a review of its 2022 internal operating budgets (Exh. AG 13-2; RR-DPU-13). These expenses consist of: (1) $362,000 in additional facilities cleaning costs; (2) $75,000 in additional HVAC operation; (3) $380,000 in additional IT costs; and (4) $171,000 in telephone expenses for customer service representatives continuing to work from home (Exhs. DPU 56-2; AG 13-2). The Company states that because its operations have changed as a result of the pandemic experience, these additional expenses will continue to be incurred for the foreseeable future and have thus been incorporated in the Company's cost of service (Exhs. DPU 3-2; ES-REVREQ-2, Sch. 9, at 1 (Rev. 4)). The Company excluded the remaining $2,243,610 from its proposed cost of service (Exh. ES-REVREQ-2, Sch. 9, at 1 (Rev. 4)).

2. Positions of the Parties

a. Attorney General

The Attorney General accepts NSTAR Electric's revised estimate of $988,000 in ongoing incremental COVID-19 responses costs as appropriate (Attorney General Brief at 119, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 31-32; AG-DJE-Surrebuttal-1, at 2). Therefore, the Attorney General accepts the Company's proposed reduction of $2,243,610 to its test year cost of service (Attorney General Brief at 119).

b. Company

NSTAR Electric maintains that it has appropriately identified its recurring COVID-19 response costs (Company Brief at 219, citing Exh. DPU 56-2; RR-DPU-13). The Company also states, as noted by the Attorney General, that it has appropriately eliminated non-recuring COVID-19 response expenses from its proposed cost of service (Company Brief at 219-220, citing Exh. ES-REVREQ-2 (Rev. 2).

3. Analysis and Findings

The Department's long-standing precedent allows only known and measurable changes to test-year expenses to be included in a company's cost of service. D.T.E. 98-51, at 61-62, citing Dedham Water Company, D.P.U. 84-32, at 17 (1984). Further, the Department permits a company to include expenses in its cost of service if a company can demonstrate that the expense is either annually or periodically recurring or, if non-recurring, is extraordinary in nature and amount as to warrant their collection by amortizing them over an appropriate time period. D.P.U. 1270/1414, at 33; see also D.P.U 89-114/90-331/91-80 (Phase One) at 152; Western Massachusetts Electric Company, D.P.U. 88-250, at 65-67 (1989).

The Department has previously recognized that the COVID-19 pandemic has caused not only a public health emergency, but also a significant economic disruption to both customers and jurisdictional gas, electric, and water distribution companies throughout the country. D.P.U. 20-58, Order Opening Inquiry and Establishing Working Group at 2 (May 11, 2020); D.P.U. 20-58-A, Order on Customer Outreach Plan at 5 (June 26, 2020).

While utilities in general faced shifts in demand and usage, increased operational burdens, collections shortfalls, and voluntary and mandatory moratoriums on disconnections, their employees also faced significant disruptions in their day-to-day working conditions. These disruptions necessitated remote work arrangements for those employees whose duties could be performed remotely, including access to IT that an individual employee would not be reasonably expected to personally possess (Exh. DPU 3-2). Because a significant number of employees are considered essential workers who do not have the ability to work remotely, the Company continued to incur facilities cleaning expenses to comply with the cleaning guidelines prescribed by the Center for Disease Control ("CDC") as well as to ensure safe workspaces for its employees (Exh. DPU 3-2). With changes in CDC cleaning protocols and transitions to more of a hybrid work environment in 2021 and thereafter, the Department is satisfied that the test-year expense is not representative of the Company's ongoing COVID-19 response costs that will be incurred in the future. Nonetheless, we recognize that some level of additional COVID-19 response costs will continue to be incurred for an indefinite time.

The Department has examined the Company's calculations and assumptions behind its proposed $988,000 in ongoing COVID-19 response expenses (Exh. DPU 56-2; Tr. 3, at 279-281; RR-DPU-13). The recurring facility cleaning and maintenance costs of $362,000 consists of: (1) $166,000 in increased cleaning of high-traffic areas and touch points identified for each of the Company's Massachusetts facilities; (2) $177,000 in janitorial overtime calculated for each facility; and (3) $19,000 in costs associated with stocking the approximately 150 sanitation stations located at these facilities (Exh. DPU 56-2; Tr. 3, at 277-278; RR-DPU-13). The recurring electricity costs of $75,000 are associated with additional run times for HVAC equipment based on both CDC and professional engineering guidelines, with a partial offset for lower base electricity costs versus pre-pandemic consumption levels (Exh. DPU 56-2; Tr. 3, at 279-280; RR-DPU-13). The recurring IT costs of $380,000 assume a 25 percent reduction from 2021 expenses as employees transition from remote work to in-office work (Exh. DPU 56-2; Tr. 3, at 280; RR-DPU-13). The recurring customer service costs of $171,000 are based on the Company's allocated share of the $501,120 in increased costs associated with approximately 200 Eversource customer service agent expenses working 20 days a month (Exh. DPU 56-2; Tr. 3, at 279-281; RR-DPU-13). Based on our review, the Department finds that the $988,000 identified by the Company as ongoing COVID-19 response costs is more representative of its ongoing expenses than test-year expense. Aquarion Water Company of Massachusetts, D.P.U. 11-43, at 182-183 (2012); D.P.U. 10-55, at 445. The Department also finds that these costs represent a known and measurable change to test-year cost of service. See D.P.U. 10-55, at 445; D.P.U. 09-30, at 211; D.P.U. 08-35, at 108; Oxford Water Company, D.P.U. 88-171, at 13-14 (1989). Accordingly, the Department allows the $988,000 identified by the Company as ongoing COVID-19 response costs.

I. Employee Retention Credit

1. Introduction

The Coronavirus Aid, Relief, and Economic Security Act of 2020 established an employee retention credit ("ERC") to incentivize companies to retain employees during the

COVID-19 pandemic (RR-AG-2).[115] The ERC operates in the form of a payroll tax credit that is claimed on an employer's quarterly Form 941 tax filings; during 2020, the credit was equal to 50 percent of up to $10,000 in qualified wages paid to an employee (RR-AG-2). While NSTAR Electric had not yet received any of these credits during the test year, the Company booked the expected credits to be received for the years 2020 and 2021 to Account 408, Payroll Taxes (Exh. AG 11-12). The Company estimated that its share of ERCs for 2020 was $1,823,800 (Exh. AG 11-12).

NSTAR Electric considered the ERC credits to be non-recurring because they were not expected to be available in the future, and therefore removed the anticipated ERC credit from its test-year cost of service (Exhs. ES-REVREQ-1, at 58; ES-REVREQ-2, Sch. 9 (Rev. 4); Tr. 1, at 85-86). This adjustment resulted in an increase of $1,823,800 to its test-year cost of service (Exhs. ES-REVREQ-2, Sch. 9 (Rev. 4); ES-RR/CCP/Comp-Rebuttal-1, at 34; AG 21-5).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the treatment of the ERC in this proceeding should be consistent with the treatment applied in D.P.U. 20-91 (Attorney General Brief at 120; Attorney General Reply Brief at 35). The Attorney General reasons that if the ERC

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115 Section 206 of the Taxpayer Certainty and Disaster Tax Relief Act of 2020, enacted as Division EE of the Consolidated Appropriations Act, 2021, modified the provisions of the ERC and extended its application to July 1, 2021. Pub. L. No. 116-260, 134 Stat. 1182 (December 27, 2020).

was a credit to expense and was non-recurring, then it should be eliminated from the determination of the Company's revenue requirement (Attorney General Brief at 119-120). Further, the Attorney General argues that for consistency, if the Department eliminates the ERC from NSTAR Electric's revenue requirement here, then the ERC must also be eliminated from any level of COVID-19 expense that the Company is ultimately authorized to recover in D.P.U. 20-91 (Attorney General Brief at 120; Attorney General Reply Brief at 35).

b. Company

NSTAR Electric argues that it has appropriately eliminated the effects of the ERC on its cost of service (Company Brief at 220, citing Exhs. AG 11-12; AG 11-22; AG 13-4; AG 21-5; Tr. 1, at 83-86; RR-AG-2; Company Reply Brief at 40-41). According to the Company, because the ERC was not included as an offset in its request to recover incremental COVID-19 costs in D.P.U. 20-91, the ERC must be removed from cost of service to avoid an improper reduction to cost of service (Company Brief at 220, citing RR-AG-2). The Company notes that it will offset any COVID-19 response costs that are ultimately authorized in D.P.U. 20-91 with the ERC (Company Reply Brief at 40-41).

3. Analysis and Findings

The Department typically includes a test year level of expenses in cost of service and will adjust this level only for known and measurable changes. Milford Water Company, D.P.U. 17-107, at 104 (2018), citing D.P.U. 11-01/D.P.U. 11-02, at 345; D.P.U. 07-71, at 120; D.P.U. 87-260, at 75. In this regard, the Department has consistently held that there are three classes of expenses that are recoverable through base rates: (1) annually recurring expenses; (2) periodically recurring expenses; and (3) nonrecurring extraordinary expenses. D.P.U. 17-107, at 104-105, citing D.P.U. 11-01/D.P.U. 11-02, at 345; D.T.E. 98-51, at 35; D.P.U. 95-118, at 121-122; D.P.U. 1270/1414, at 32-33.

The provisions of the ERC expired, with some limited exceptions not applicable to the Company, during the fourth quarter of 2021.[116] Consequently, the Department finds that the ERC is a nonrecurring credit to payroll taxes, and that its inclusion in the Company's cost of service would produce a distorted level of payroll tax expense. See, e.g., Aquarion Water Company of Massachusetts, D.P.U. 17-90, at 247-248 (2018). Further, we find that the Company has properly calculated the necessary adjustment to its proposed cost of service (Exhs. ES-REVREQ-2, Sch. 8, at 2 (Rev. 4); AG 11-12; AG 11-22; AG 21-5; Tr. 1, at 83-86; RR-AG-2). Therefore, the Department accepts the Company's proposed adjustment, and we remove the ERC from the Company's test-year cost of service. The elimination of this credit produces an increase of $1,823,800 to the Company's test-year cost of service (Exhs. ES-REVREQ-2, Sch. 9 (Rev. 4); ES-RR/CCP/Comp-Rebuttal-1, at 34; AG 21-5).

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116 See Internal Revenue Bulletin: 2021-65, Termination of the Employee Retention Credit Under Section 3134 of the Code in the Fourth Calendar Quarter of 2021 for Certain Employers.

J. Work Asset Management Expenses

1. Introduction

As part of Eversource Energy's technology modernization initiatives, it has embarked on the implementation of a new Work and Asset Management System ("WAM System") across all of its electric transmission and distribution operations, including those of the Company (Exh. ES-ADDITIONS-10, at 1059; Tr. 7, at 766-767). During the test year, NSTAR Electric booked approximately $3,200,000 in expenditures associated with the implementation of the WAM System to Account 921, Office Supplies and Expenses (Exh. DPU 3-14). These expenses represented the cost of employee training intended to familiarize Company personnel with the use of the WAM System (Exh. AG 16-15).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the WAM System training expenses are nonrecurring and should be excluded from the Company's proposed cost of service (Attorney General Brief at 117; Attorney General Reply Brief at 35). In support of her position, the Attorney General contends that once the Company's employees are appropriately trained on the use of the WAM System, these training costs should not be expected to continue (Attorney General Brief at 117). The Attorney General also contends that the Company's Account 921 expenses for 2021 decreased by an amount similar to what would be expected if the WAM System training costs were removed and were consistent with the 2019 expenses when adjusted for inflation and "some level" of continuing costs related to COVID-19

(Attorney General Brief at 117-118, citing Exhs. AG DJE-1, at 6-7; AG 1-2, Att. (6)(e) at 170 (Supp. 1)).

Further, the Attorney General dismisses the Company's claim that it has incurred significant training expenses during the first quarter of 2022 as a non sequitur unsupported by any evidence (Attorney General Brief at 118). She points out that during Department questioning, the Company was unable to confirm whether the increase in expenses booked to Account 921 during the first quarter of 2022 was attributable to training costs (Attorney General Brief at 118, citing Tr. 7, at 764; Attorney General Reply Brief at 35)

Based on the nature of the Company's test-year WAM System training expenses and lack of evidence that the Company's test-year Account 921 expenses are representative of future expenditures, the Attorney General argues that the Company's proposed WAM System training expenses are nonrecurring (Attorney General Brief at 118; Attorney General Brief at 35). Thus, she asserts that the Company's proposed cost of service should be reduced by $2,777,920, which represents the portion of the $3,200,000 in total expenses associated with distribution operations (Attorney General Brief at 119, citing Exh. AG DJE-1, at 7, Sch. 1).[117]

[117] The Attorney General calculates that, after factoring in working capital, return requirements, and income taxes, her proposed adjustment produces an overall reduction of $3,038,162 to the Company's proposed cost of service (Exh. AG DJE-1, at 7, Sch. 1).

b. Company

NSTAR Electric argues that while the WAM System training costs are not in themselves a recurring expense, the Company continually conducts other trainings across its organization to ensure that employees and contractors are able to perform their duties consistent with Company systems, procedures, and processes (Company Brief at 211, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 32; AG 16-15). For example, the Company maintains that although there are no incurred or forecasted WAM System training expenses for 2022 and 2023, its overall Account 921 expenses during 2021 were $6,939,589, and were $6,471,458 during the first quarter of 2022 (Company Brief at 211, citing Exhs. ES-RR/CPP/Comp-Rebuttal-1, at 32-33; AG 21-4). The Company contends that it will continue to incur training expenses, including training on a range of IT platforms that ESC is developing over the next four years (Company Brief at 211, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 33; Company Reply Brief at 39, citing Exhs. DPU 48-1; ES-ADDITIONS-8A at 2-3). The Company argues that because training costs are recurring, its test-year WAM System training costs provides an appropriate representative expense to be included in the cost of service (Company Brief at 212, citing Exh. ES-RR/CPP/Comp-Rebuttal-1, at 33; Tr. 7, at 766-769).

In the alternative, NSTAR Electric proposes that if the Department determines that its WAM System training costs are not representative, then the expenses should be normalized rather than eliminated in their entirety (Company Reply Brief at 39-40). According to the Company, normalization places a certain degree of risk back on the utility that would be expected in the course of operations (Company Reply Brief at 40, citing D.P.U. 92-101, at 48-49; D.P.U. 92-78, at 9; D.P.U. 1720, at 89). The Company proposes that if the Department declines to allow the test-year expense in full, a normalization period of four years would be appropriate in view of the relatively short life associated with IT (Company Reply Brief at 39 n.5, citing Bay State Gas Company, D.P.U. 13-75, at 261-263 (2014)).

3. Analysis and Findings

Test-year expenses that recur on an annual basis are eligible for full inclusion in cost of service unless the record supports a finding that the level of the expense in the test year is abnormal. D.P.U. 1270/1414, at 33. The Department's longstanding policy regarding adjustments to O&M expense levels is to set a representative level of expenses that are reasonably expected to recur on a normal annual basis. D.P.U. 1270/1414, at 33.

Account 921 encompasses a wide range of expenditures, representing office supplies and expenses incurred in connection with the general administration of the utility's operations that are assignable to specific administrative or general departments, and not specifically provided for in other accounts. 18 CFR Part 101, Account 921. Examination of the Company's bookings to Account 921 and its related subaccounts for the years 2018 through 2021 indicates that the most significant activity occurs in three subaccounts, with a fourth subaccount acting as a clearing account (Exhs. DPU 3-14; AG 1-2, Att. (6)(e) at 170 (Supp. 1); AG 1-34, Atts. (d) at 25, (e) at 18-19, (f) at 26, (g) at 19, (h) at 27, (i) at 19-20, (k) at 27 (Supp. 1), and (l) at 20 (Supp. 1)). While the Company points to the significant increase in its Account 921 expenses for the first quarter of 2022, the Company was unable to quantify the reasons for this increase aside from generalized observations about other training programs (Tr. 7, at 765, 768-769). Moreover, the magnitude of the reported increase (i.e., more than doubling test-year expense on an annualized basis) is suggestive of some unusual activity during that period. On this basis, the Department finds that there is insufficient evidence to support consideration of the Company's expense levels for the first quarter of 2022 in assessing the representativeness of its test-year Account 921 expenses.

While the Department acknowledges that utilities engage in employee training on an ongoing basis, the WAM expenses are nonrecurring, and the Company has failed to demonstrate that its test-year Account 921 expenditures are representative of the level of expense that will be incurred in the future. Therefore, the Department finds it appropriate to remove the test-year WAM expenses from the Company's proposed cost of service. D.P.U. 10-55, at 332-333; D.P.U. 08-35, at 120-125.[118] Of the $3,200,000 in test year WAM expenses, the Company allocates 13.19 percent, or $422,080, to its transmission operations (Exhs. AG-DJE-1, at 7, Sch 1; DPU 3-2, Att.). The remaining 86.81 percent, or $2,777,920, represents the portion associated with distribution operations (Exhs. DPU 3-2, Att.; AG-DJE-1, at 7, Sch. 1). Accordingly, the Department reduces the Company's proposed cost of service by $2,777,920.

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118 NSTAR Electric's alternative proposal to normalize the WAM System training expenses was offered on reply brief. We find the proposal to be untimely, as neither the Department nor the remaining parties had an opportunity to conduct meaningful investigation.

K. Rate Case Expense

1. Introduction

Initially, the Company estimated that it would incur $3,816,170 in rate case expense (Exhs. ES-REVREQ-1, at 100; ES-REVREQ-2, Sch. 19). Based on its final invoices and projected costs to complete the compliance filing, the Company proposes a total rate case expense of $3,108,191 (Exhs. ES-REVREQ-2, Sch. 19 (Rev. 4); DPU 30-8, Att. A (Supp. 3)). NSTAR Electric'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) cost of capital study, and (4) allocated cost of service ("ACOSS") study (Exhs. ES-REVREQ-1, at 94-95, 100; ES-REVREQ-3, WP 19; AG 5-35, Att. A; DPU 30-1).[119]

The Company proposes to normalize the rate case expense over a five-year period based on the statutory requirement (Exhs. ES-REVREQ-1, at 100; ES-REVREQ-2, Sch. 19 (Rev. 4); DPU 30-21). Normalizing the Company's proposed rate case expense of $3,108,191 over five years produces an annual expense of $621,638 (Exh. ES-REVREQ-2, Sch. 19 (Rev. 4)).

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[119] The Company utilized ESC or internal employees as witnesses for certain aspects of the rate case, such as revenue requirement, employee compensation and benefits, and rate design, as well as legal support. The payroll costs for these employees are included in employee compensation and benefits rather than in rate case expense (Exh. DPU 30-11; Tr. 14, at 1507).

2. Positions of the Parties

The Company maintains that it appropriately conducted a competitive solicitation process consistent with the Department's requirements (Company Brief at 198-199). The Company also asserts that it has taken steps to control rate case expense, including selecting outside service providers that provided blended hourly fees, discounts, and not-to-exceed levels (Company Brief at 199, citing Exhs. DPU 30-3; DPU 30-17). In addition, NSTAR Electric maintains that it performs a detailed review of the outside service providers' invoices and resolves any questions or anomalies prior to approving for payment (Company Brief at 199-200, citing Exh. DPU 30-17). No intervenor addressed 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. New England Gas Company, D.P.U. 10-114, at 219-220 (2011); 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 Barnstable Water Company, D.P.U. 93-223-B at 16-17 (1993).

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 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 expenses, 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 seeks to include expenses associated with the following: (1) PBR proposal; (2) depreciation study; (3) cost of capital study; (4) ACOSS study; (5) legal services; and (6) rate case support (Exhs. ES-REVREQ-1, at 94-95, 100; ES-REVREQ-3, WP 19; DPU 30-1; DPU 30-8, Att. A (Supp. 3); DPU 30-18). NSTAR Electric provided documentation demonstrating that it conducted a competitive bidding process for each of its service providers utilized solely for this base distribution rate proceeding (Exhs. DPU 30-1 & Atts.; DPU 30-7; DPU 30-18; DPU 50-2). The Company also utilized a managed services program vendor who conducted analysis and prepared documentation supporting the filing of exhibits related to capital additions as well as administrative support in submitting filings pursuant to a competitive bidding process that was conducted in 2017 (Exhs. DPU 30-7; DPU 30-18).

Based on our review of the RFPs and responses, we conclude that the Company's choices regarding its consultants, including attorneys, were reasonable and cost effective (Exhs. DPU 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.). We also find that NSTAR Electric 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 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.). 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 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.). Based on the foregoing, the Department concludes that NSTAR Electric conducted a fair, open, and transparent competitive bidding process for the attorneys and consultants (Exhs. DPU 30-1, Atts. (h) through (l); DPU 30-2 & Atts.; DPU 30-3 & Att.).

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 NSTAR Electric and finds that the invoices are properly itemized (see, e.g., Exhs. DPU 30-8, Atts. B through G; DPU 30-8, Atts. E, F (Supp. 3)). In addition, 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 30-8, Atts. B through G; DPU 30-8, Atts. E, F (Supp. 3)).

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).

NSTAR Electric proposes a five-year rate case expense normalization period based on the period for filing rate cases pursuant to Massachusetts law (Exhs. ES-REVREQ-1, at 101-102; DPU 50-2). The Company also provided a calculation of the average interval between its last four base distribution rate cases, which resulted in an average interval of ten years (Exh. ES-REVREQ-4, Sch. 3).[120] In its calculation, NSTAR Electric did not include any base distribution rate cases involving the former WMECO. Utilizing both NSTAR Electric's and the former WMECo's filings, the average interval between the Company's last four base distribution rate cases is seven years (Exh. ES-REVREQ-4, Sch. 3).[121] As discussed in Section IV.D.5.a above, the Department has approved a PBR plan for the Company that includes a five-year term and stay-out provision. The Department has considered the term of a PBR in establishing an appropriate rate case expense normalization

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120 In addition to the current filing, NSTAR Electric's prior base distribution rate filings were D.P.U. 17-05, Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/NSTAR Gas Company, D.T.E. 05-85 (2005), and D.P.U. 92-250 (Exh. ES-REVREQ-4, Sch. 3, at 1). Between D.P.U. 22-22 and D.P.U. 17-05, the interval is 4.99 years; between D.P.U. 17-05 and D.T.E. 05-85, the interval is 11.11 years; and between D.T.E. 05-85 and D.P.U. 92-250, the interval is 13.06 years. The sum of these intervals divided by three and rounded to the nearest whole number results in a normalization period of ten years (29.18/3 = 9.73).

121 The former WMECo's prior base distribution rate fillings were D.P.U. 17-05, D.P.U. 10-70, and Western Massachusetts Electric Company, D.T.E. 06-55 (2007). Between D.P.U. 22-22 and D.P.U. 17-05, the interval is 4.99 years; between D.P.U. 17-05 and D.P.U. 10-70, the interval is 6.53 years; and between D.P.U. 10-70 and D.T.E. 06-55, the interval is 3.72 years. The sum of these intervals divided by three and rounded to the nearest whole number results in a normalization period of five years (15.24/3 = 5.08). The average of NSTAR Electric's interval and the former WMECo's interval is 7.41 years (rounded to seven).

period. D.P.U. 17-05, at 281-282; D.P.U. 09-30, at 241; D.P.U. 07-71, at 105; D.T.E. 05-27, at 163-164; D.T.E. 03-40, at 163; D.T.E. 01-56, at 75; D.P.U. 96-50 (Phase I) at 78. 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. 17-05, at 282; D.P.U. 96-50 (Phase I) at 78. Accordingly, the Department finds that a five-year normalization period is appropriate.

e. Conclusion

The Company proposed and the Department has accepted a final rate case expense of $3,108,191 (Exhs. ES-REVREQ-2, Sch. 19 (Rev. 4); DPU 30-8 (Supp. 3), Att. A). Based on a five-year normalization period, the annual level of rate case expense to be included in the Company's cost of service is $621,638 ($3,108,191 divided by five years). The annual level of rate case expense approved in this proceeding is reflected in Schedule 2 below.

VIII. EXCESS ACCUMULATED DEFERRED INCOME TAXES

A. Introduction

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 ("2017 TCJA") was signed into law.[122] Among other things, 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,

[122] 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.

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).[123]

The Department determined, among other things, 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.

The Department subsequently directed NSTAR Electric to refund excess ADIT to ratepayers through a 2017 Tax Act Credit Factor ("2017 TACF") as a separate reconciling component in the Company's annual rate adjustment/reconciliation filing. D.P.U. 18-15-E at 38-39. The Department determined that the credit factor would remain in effect until the excess ADIT balance is transferred to the new rates that are established in the Company's next base distribution rate proceeding, or unless otherwise directed by the Department. D.P.U. 18-15-E at 39 n.34.

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

B. Company Proposal

NSTAR Electric states that its excess ADIT balance as of December 31, 2021, was $428,741,374[124] before tax gross-up and $589,902,826 after tax gross-up (Exhs. ES-REVREQ-2, Sch. 32 (Rev. 4); DPU 51-7). From this amount, the Company deducted a flow-through adjustment of $57,583,262 for items that are primarily depreciation flow-through, and income tax deficiency amounts prior to the 2017 TCJA rate change (Exhs. DPU 18-2; DPU 51-7). Overall, the Company reports a grossed-up net excess ADIT balance of $532,319,565 at year-end 2021 (Exhs. ES-REVREQ-2, Sch. 1, at 4, Sch. 32 (Rev. 4); DPU 51-7).

The Company proposes to continue refunding excess ADIT related to the 2017 TCJA to customers through the 2017 TACF (Exh. ES-REVREQ-1, at 143). As such, the Company does not propose any excess ADIT-related adjustments to the cost of service in this proceeding (Exh. ES-REVREQ-1, at 143). No party addressed the Company's excess ADIT proposal on brief.

C. Analysis and Findings

In D.P.U. 18-15-E, at 39, the Department found that given that NSTAR Electric would refund excess ADIT to ratepayers through its annual rate adjustment/reconciliation filing, the amounts are subject to reconciliation once the final tax liabilities come due. Further, we noted that we fully expected NSTAR Electric to make these determinations as

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124 Of this amount, $47,637,826 was attributable to non-property related excess ADIT, and $381,103,548 was attributable to property-related excess ADIT (Exh. DPU 51-7).

soon as practicable and to implement appropriate adjustments, supported by testimony and exhibits, in future reconciliation filings. In the instant proceeding, the Company has provided total excess ADIT to be refunded to customers as a result of the 2017 TCJA and shown that it tracked the difference between the excess ADIT amortization and the actual refunds through 2017 TACF over time since the D.P.U. 18-15-E decision (Exhs. DPU 18-4, Att.; DPU 32-1 & Att.; DPU 61-14). Further, the Department finds the Company's reported excess ADIT balances to be acceptable (Exh. DPU 51-7).

As noted above, the Department previously directed NSTAR Electric to refund excess ADIT to ratepayers through the 2017 TACF until the Company could transfer the excess ADIT balance to new rates established in the Company's next base rate proceeding, or unless otherwise directed by the Department. D.P.U. 18-15-E, at 39 n.34. In support of its proposal to continue refunding excess ADIT through the 2017 TACF instead of transferring the balance to base distribution rates, the Company points to Budget of the U.S. Government for Fiscal Year 2023, wherein the Administration seeks to raise the federal corporate income tax rate from 21 percent to 28 percent (Exh. DPU 32-3 & Att. at 40, 135). While a change in this tax rate is not certain, if a change does occur the Company would be required to adjust the excess ADIT balance and amortization periods applicable to ensure an accurate refund to customers. We find that it would be administratively efficient for the Company to address future adjustments to the excess ADIT balance and amortization periods through the 2017 TACF. Moreover, the record shows that the balance of unprotected, non-property-related excess ADIT will be fully refunded to customers by the end of the rate year (Exh. DPU 18-4, Att.; Tr. 1, 140-141). Thus, we find that it would be inappropriate to include the balance in base distribution rates for at least the next five years. Based on these considerations, the Department finds that it is reasonable and appropriate for the Company to retain the 2017 TACF. See D.P.U. 18-150, at 197-198 (allowing National Grid (electric) to retain its tax credit provision due to potential changes Internal Revenue Service normalization requirements).[125] Accordingly, we allow the Company's proposal.

IX. PENSION ADJUSTMENT FACTOR ALLOCATION AND MOTION FOR APPROVAL OF REQUEST FOR ORAL ARGUMENT

A. Introduction

Prior to February 1, 2018, NSTAR Electric recovered a portion of its pension and PBOP expense in its base distribution rates (Exh. ES-REVREQ-7, at 2). See also D.P.U. 17-05, at 323 & n.166; NSTAR Pension, D.T.E. 03-47-C at 7 n.2 (2004).[126] Because a portion of pension and PBOP expense were embedded in base distribution rates, the Company needed to allocate these embedded expenses between its distribution and

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125 If there is a change in the federal corporate income tax rate that necessitates any adjustments to the excess ADIT balance or amortization amounts, the Department may consider opening an investigation to address the change.

126 NSTAR Electric and the former WMECo were separate companies until January 1, 2018, when WMECo was consolidated into NSTAR Electric after approval of the transaction by the Department. D.P.U. 17-05, at 4, 43-44. While a portion of NSTAR Electric's pension and PBOP expenses were recovered through base distribution rates, all of WMECo's qualified pension plan pension and PBOP costs were recovered through its own PAM. D.P.U. 17-05, at 323. In D.P.U. 17-05, the Department approved the transfer of all of NSTAR Electric's qualified pension plan pension and PBOP costs to the pension adjustment factor. D.P.U. 17-05, at 324.

transmission functions. D.T.E. 03-47-B (Phase II) at 10-11. During this time, the Company relied on a transmission allocator in its calculation of its proposed pension adjustment factors ("PAF") that varied from year to year to recognize the actual expense allocated to its transmission function based on FERC's formula rate that uses a labor allocator (Exh. ES-REVREQ-7, at 3-7). In contrast, according to the Company, the Attorney General has advocated the use of a fixed ratio of 3.84 percent using the allocation between its distribution and transmission embedded expenses in base distribution rates based on the ratio originally established for NSTAR Electric in D.T.E. 03-47 (Exh. ES-REVREQ-7, at 3).

Although the allocation issue has been resolved for the Company's post-2018 PAF filings, the allocation issue continues to affect eight PAF filings covering the years 2011 through 2018 that are currently pending before the Department. The outstanding dockets are: NSTAR Electric Company and NSTAR Gas Company, D.P.U. 11-91; NSTAR Electric Company and NSTAR Gas Company, D.P.U. 12-113; NSTAR Electric Company and NSTAR Gas Company, D.P.U. 13-184; NSTAR Electric Company and NSTAR Gas Company, D.P.U. 14-145; NSTAR Electric Company, NSTAR Gas Company, and Western Massachusetts Electric Company, D.P.U. 15-147; NSTAR Electric Company, NSTAR Gas Company, and Western Massachusetts Electric Company, D.P.U. 16-182; NSTAR Electric Company, NSTAR Gas Company, and Western Massachusetts Electric Company, D.P.U. 17-159; and NSTAR Electric Company and NSTAR Gas Company, D.P.U. 18-121.

According to the Company, the Attorney General has challenged the recovery of approximately $26,835,250 in pension costs, including carrying charges, in these dockets

(Exh. ES-REVREQ-7, at 3). The Company notes that the allocation issue has been outstanding for over ten years and maintains that lack of resolution of the issue is creating significant regulatory uncertainty (Exh. ES-REVREQ-7, at 2-3). NSTAR Electric states that the Department's resolution of this impasse is needed in this case before the Company can commit to take on the risk of a ten-year PBR Plan (Exh. ES-REVREQ-7, at 2-3).

On September 2, 2022, the Company filed its initial brief in this proceeding. In its brief, the Company addressed the pension allocation issue and requested oral argument before the full Commission because the Department did not inquire about the issue during the discovery or evidentiary hearing phase of the proceeding (Company Brief at 374-380). No other party briefed this issue. On September 7, 2022, the Company filed a Motion for Approval of Request for Oral Argument on this pension allocation issue ("Motion").[127] On September 23, 2022, the Attorney General filed an Opposition to NSTAR Electric's Motion ("Attorney General Opposition").

B. Positions of the Parties

1. Company

NSTAR Electric contends that the pension allocation issue has been unresolved for over a decade, and that the contested amount currently stands at approximately $26.8 million,

[127] The Motion is a five-page document without pagination. For purposes of the form of motions and briefs filed with the Department, the Department adopts the requirements for pagination of briefs of the Massachusetts Rules of Appellate Procedure, Rule 20(a)(5) (consecutive page numbering). For purposes of cites to the Motion in this Order, the Department identifies the page where the content appears.

including \$8.4 million in carrying costs (Motion at 3; Company Brief at 374-375). The Company asserts that given this magnitude of potential exposure, the Department must resolve the pension allocation issue so that the Company and Attorney General can decide on the appropriate next steps, including seeking judicial review if so determined (Motion at 5; Company Brief at 375-376).[128]

NSTAR Electric defends its use of a variable transmission allocator, arguing that its use was designed to match the annual ratio of transmission and distribution expenses in the PAM with the actual ratio of transmission and distribution expense approved by FERC in setting transmission rates (Company Brief at 375). Further, NSTAR Electric contends that the use of a variable transmission allocator was approved by the Department as part of the Company's compliance filing in D.T.E. 03-47.[129]

The Company also contends that it properly incorporated the allocation of pension/PBOP expense into the PAF formula (Company Brief at 376-379). In addition, the Company maintains that the Attorney General is not seeking to correct a computational error in the PAF formula, but rather seeks to modify the PAF formula itself (Company Brief at 379). According to the Company, the Massachusetts Supreme Judicial Court has repeatedly held that a mechanically applied formula rate is a fixed rate that cannot be

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128 NSTAR Electric contends that if the Department were to decide against the Company on this issue, then it would seek judicial review on the basis of reversible legal error (Company Brief at 375).

129 The Company's brief makes reference to D.T.E. 03-87, which pertains to a double-pole proceeding, and, therefore, appears to be a typographical error.

changed outside of a base distribution rate proceeding, as had been done in D.P.U. 17-05 (Company Brief at 380, citing Attorney General v. Department of Public Utilities, 453 Mass. 191 (2009)).

In support of its Motion, the Company asserts that the complexity of the method to allocate annual pension expense for the PAM necessitates oral argument to ensure that: (1) the issues are fully litigated on the record; (2) all parties have an opportunity to make a complete presentation of their respective positions; and (3) any questions that the Department may have about the parties' positions are thoroughly addressed and examined before a decision is made (Motion at 4). According to the Company, there is no record in this proceeding beyond the initial filing addressing the allocation method for annual pension expense for the PAM between distribution and transmission, the Department did not ask any questions about this issue during the conduct of this proceeding, and the Company has not had the opportunity to fully defend its position given the limited, pointed questions raised by the Attorney General (Motion at 4). Further, NSTAR Electric contends that there are multiple, complex issues of law to address that require counsel to interpret the Company's assertions (Motion at 4). Thus, the Company argues that there is a lack of defined evidence outlining the pension allocation issue on the record, and it is unreasonable and unfair to adjudicate the matter without of allowing oral argument by the parties (Motion at 4).

2. Attorney General

The Attorney General argues that the open PAF dockets are the appropriate forum for the Company to make its arguments (Attorney General Opposition at 3). Further, the

Attorney General contends that the Company has mischaracterized her position as to the pension allocation issue (Attorney General Opposition at 3). According to the Attorney General, in the PAF dockets, she did not advocate for a fixed 3.84-percent allocation factor, but instead argued that the Company erred in its calculation of the PAF and needs to adjust the transmission allocator within the PAF where the pension and PBOP currently in rates enters into the calculation (Attorney General Opposition at 5). The Attorney General contends that her recommendation would only require corrective calculation of the Company's PAF, which can be achieved in the PAF dockets and is not required to be addressed in this instant base distribution rate case (Attorney General Opposition at 4-5).

The Attorney General also argues that the Motion is untimely and unsupported by a showing of good cause to excuse the delay (Attorney General Opposition at 2-3, citing 220 CMR 1.01(4), 1.02(5), 1.11(2)). Further, the Attorney General contends that, if granted, the Motion would result in oral argument being held after the briefing period, thereby denying intervenors an opportunity to appropriately respond to arguments raised at the hearing (Attorney General Opposition at 3). Thus, the Attorney General asserts that the Motion should be denied (Attorney General Opposition at 3).

C. Analysis and Findings

The Department first will address the Motion. The Department's regulations governing requests for oral arguments can be in found in 220 CMR 1.11(2), which provides:

> Oral Argument, When Made. When, in the opinion of the presiding officer, time permits and the nature of the proceedings, the complexity or importance of the [issues] of fact or law involved, and the motion or at the request of a party or staff counsel at or before the close of the taking of testimony, allow

> and fix a time for the presentation of oral argument, imposing such limits of time on the argument as deemed appropriate in the proceeding. Such argument shall be transcribed and bound with the transcript of testimony.

The decision to allow for oral argument is completely within the Department's discretion. Bay State Gas Company, Interlocutory Order on Appeal of Hearing Officer Ruling on Intervention, D.P.U. 16-12, at 8 n.6 (March 8, 2016); The Berkshire Gas Company, D.P.U. 15-178, Interlocutory Order on Appeal of Hearing Officer Ruling on Intervention and Motion for Clarification at 8 n.6 (February 17, 2016); The Berkshire Gas Company, D.P.U. 15-48, Interlocutory Order on Motion to Stay and Appeals of Hearing Officer Ruling on Intervention at 15 n.6 (June 19, 2015); NSTAR Electric Company, D.P.U. 12-19, at 10 n.10 (2012); D.P.U. 11-43, at 6, 9. Further, the Department finds no statutory right to oral argument before an administrative agency.[130]

As an initial matter, the Motion was filed approximately six weeks after the close of hearings, and the Company provides no reason for this inordinate delay. As such, we find the Motion is untimely. Nevertheless, even if the Motion was made within the time prescribed by 220 CMR 1.11(2), the Department finds that the Company did not demonstrate that oral argument is warranted in this proceeding. NSTAR Electric's prefiled initial testimony, supporting appendix, initial brief, and Motion provided ample background

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130 The Massachusetts Administrative Procedures Act, G.L. c. 30A, contains no such right. Further, the Department does not find that due process interests require oral argument. See, e.g., Federal Communications Commission v WJR, The Goodwill Station, Inc., 337 U.S. 265, 275 (1949) (due process law as guaranteed by the Fifth Amendment does not require federal administrative agencies to accord oral argument).

information and Company commentary on the pension allocation issue (Exhs. ES-REVREQ-1, at 209-210; ES-REVREQ-7; Company Brief at 374-380; Motion at 2-5). Further, the remaining parties had the opportunity to issue discovery, conduct cross-examination of witnesses, file comments, and respond to the Motion to address the pension allocation issue. Oral argument was not necessary to flesh out the issues. Based on these considerations, the Motion is denied.

Notwithstanding our findings above, the Department will address the issue of NSTAR Electric's pension allocation in the pending PAF dockets. Three cases, D.P.U. 11-91, D.P.U. 12-113, and D.P.U. 13-184, have been fully briefed by both the Company and the Attorney General. The Attorney General has submitted prefiled testimony in D.P.U. 14-145, D.P.U. 15-147, D.P.U. 16-182, D.P.U. 17-159, and D.P.U. 18-121. Given the procedural posture of the Company's PAF proceedings, including the evidentiary record developed to date, the Department finds that it is more appropriate and efficient to continue to adjudicate the pension allocation issue in those open dockets.[131] Accordingly, the Department declines to examine NSTAR Electric's pre-2018 pension allocations in this Order.

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131 Given the nature of the unresolved issue and in the exercise of its discretion, the Department will consider whether oral argument in any of these open dockets is necessary.

X. STORM COST RECOVERY MECHANISM

A. Introduction

The parameters of NSTAR Electric's current storm cost recovery mechanism ("storm fund") were approved in the Company's last base distribution rate proceeding, D.P.U. 17-05. In particular, the Department: (1) established that a storm-fund-eligible event must meet a $1.2 million incremental O&M cost threshold; (2) set the annual storm fund contribution collected through base distribution rates at $10 million; (3) approved an annual O&M expense associated with storm events of $3.6 million; (4) approved a symmetrical cap of $30 million on the storm fund balance; (5) approved the accrual of carrying charges at the prime rate for storm-fund-eligible events, with recovery to begin at the time that the costs are incurred; and (6) allowed the Company to seek cost recovery through the exogenous cost provision of the PBR mechanism (pending a prudence review) provided that the combination of any single storm in excess of $30 million and balance of the storm fund exceeds $75 million. D.P.U. 17-05, at 547-559. The Department also established reporting requirements to allow for expedited and efficient review of the Company's storm-cost filings and for an evaluation of the prudency of storm-related costs. D.P.U. 17-05, at 562.

B. Company Proposals

1. Storm Fund Modifications

The Company proposes to continue its storm fund mechanism with four modifications. First, the Company proposes to increase the storm-fund-eligible event threshold to $1.3 million in incremental O&M costs (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162). NSTAR Electric states that its proposal is based on increasing the current threshold of \$1.2 million by the cumulative inflation change of the GDP-PI, as reported by the U.S. Bureau of Economic Analysis, from 2016 through 2020 (Exhs. ES-REVREQ-1, at 163; DPU 4-7. Att.).

Second, the Company proposes to increase the annual storm fund contribution collected through base distribution rates to \$31 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 181; ES-REVREQ-2, Sch. 22 (Rev. 4)). According to the Company, its current annual storm fund allowance of \$10 million is insufficient, given the large disparity between the annual average of incremental O&M costs related to storm-fund-eligible events experienced during the last several years and the amount currently amortized through base distribution rates (Exh. ES-REVREQ-1, at 163). The Company states that its proposal is based on the average monthly storm costs of approximately \$2.6 million incurred between February 1, 2018 (the date that rates established in D.P.U. 17-05 were implemented) through the end of the test year, multiplied by twelve months (Exhs. ES-REVREQ-1, at 181; ES-REVREQ-2, Sch. 22 (Rev. 4)).

Third, NSTAR Electric proposes to increase the annual O&M expense associated with storm events to \$7.8 million (Exh. ES-REVREQ-1, at 164-164). The Company bases this proposal on the average number of storm-fund-eligible events from 2017 through 2020, which were six events on average, multiplied by the proposed storm-fund-eligible event threshold of \$1.3 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 164-165; AG 12-6).

Fourth, NSTAR Electric proposes that, for each storm-fund-eligible event subsequent to the seventh event in a calendar year, the Company is permitted to recover the storm-fund-eligible event threshold of $1.3 million through the storm fund (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 165-166, 169-170; DPU 34-1). Conversely, if there are less than five storm-fund-eligible events in a calendar year, customers would receive a $1.3 million credit for the number of events less than five that did not occur (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 169-170; DPU 34-1).

2. Other Proposals

In addition to the proposed modifications to the storm fund, the Company sets forth three additional proposals. First, the Company proposes to recover the current storm-fund-eligible event threshold of $1.2 million for six storm-fund-eligible events that occurred in 2020 and seven storm-fund-eligible events that occurred in 2021, for a total of $15.6 million in costs (Exh. ES-REVREQ-1, at 173; Company Reply Brief at 49).

Second, NSTAR Electric proposes to maintain its current storm cost adjustment recovery factor ("SCRAF") and to recover, beginning on January 1, 2023, and subject to a future prudence review and reconciliation, a portion of the Company's outstanding storm fund deficiency of approximately $106 million over a five-year period for an annual amortization amount of $21.2 million (Exhs. ES-REVREQ-1, at 178-180; DPU 4-8, Att. (b)).[132]

[132] Currently, the Company recovers an annual amortization amount of $28 million through the SCRAF for costs associated with storm-fund-eligible events that occurred prior to February 1, 2018 (Exh. ES-REVREQ-1, at 178). On December 31, 2022,

Third, the Company proposes to recover through the SCRAF beginning on January 1, 2024, subject to future prudence review and reconciliation, $196.2 million in costs associated with two exogenous storm events – Tropical Storm Henri and the October 2021 Nor'easter (Exhs. ES-REVREQ-1, at 179-180; ES-REVREQ-4, Sch. 11(d); DPU 4-8, Att. (c); DPU 4-13).[133] The Company proposes to recover the costs for these two storm events over a five-year period for annual amortization amount of $39.2 million (Exhs. DPU 4-8, Att. (c), at 1; DPU 4-13; DPU 4-14 & Att.).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that NSTAR Electric's storm cost recovery proposals improperly attempt to insulate the Company from all storm-related financial risk (Attorney General Brief at 133, citing D.P.U. 15-155, at 83; D.P.U. 09-39). In particular, the Attorney General recommends that the Department reject four of the Company's proposals.

First, the Attorney General argues that Company's proposal to increase the annual storm fund contribution collected through base distribution rates to $31 million represents a significant shift of financial risk to ratepayers (Attorney General Brief at 138). Moreover, the Attorney General contends that the Company's request is unnecessary because it can

the amortization period associated with these storms expires (Exh. ES-REVREQ-1, at 178).

133 The Company notes that the amortization of the exogenous cost currently collected through the SCRAF expires on December 31, 2023 (Exhs. ES-REVREQ-1, at 179; DPU 4-13, at 1).

recover additional storm costs through the existing SCRAF, which the Company proposes to extend in the instant proceeding (Attorney General Brief at 138, citing Exh. ES-REVREQ-1, at 181).

Second, the Attorney General argues that NSTAR Electric's proposal to recover the storm-fund-eligible event threshold of $1.3 million for each storm after the seventh storm also seeks to eliminate the Company's storm-related financial risk (Attorney General Brief at 137, citing D.P.U. 15-155, at 78). In this regard, the Attorney General contends that NSTAR Electric already is insulated from the cost-risk of storms due the large number of storm cost recovery mechanisms approved for the Company in recent years (Attorney General Brief at 138, citing D.P.U. 17-05, at 547-548, 550, 553-555, 559, 561, 562, NSTAR Electric Company, D.P.U. 21-133; D.P.U. 21-75/D.P.U. 21-76; NSTAR Electric Company, D.P.U. 20-29). Moreover, the Attorney General asserts that NSTAR Electric earns an ROE that, in part, is intended to compensate the Company for such risks (Attorney General Brief at 138). Finally, the Attorney General asserts that maintaining a fixed number of storm-fund-eligible event threshold amounts in base distribution rates is a fair and reasonable way to balance financial risk between the Company and its ratepayers (Attorney General Brief at 137).

Third, the Attorney General argues that NSTAR Electric's request to recover the storm-fund-eligible event threshold amounts for the six storm events in 2020[134] should be

[134] The Attorney General does not address the Company's request to recover the storm-fund-eligible event threshold amounts attributable to seven storms in 2021.

rejected because it contravenes the Department's Order in D.P.U. 17-05, it would retroactively alter the entire regulatory treatment of storm costs and storm fund cost eligibility, and it would improperly rebalance the risk for storm recovery in the Company's favor (Attorney General Brief at 135-136, citing D.P.U. 17-05, at 548-549; Attorney General Reply Brief at 41-43). Further, the Attorney General contends that if NSTAR Electric's proposal is allowed, it would triple the recovery currently allowed in base distribution rates and would represent one-and-a-half times the amount the Company proposes to include in base distribution rates going-forward (Attorney General Reply Brief at 41). In addition, the Attorney General asserts that approving this proposal would allow the Company to consistently recover storm-related costs when such costs exceed the representative amount set in base distribution rates, with no corresponding path for ratepayers to benefit in the years when costs are less than those in base distribution rates (Attorney General Reply Brief at 43).

Finally, the Attorney General argues that the Department should reject the Company's proposal to recover costs associated with Tropical Storm Henri and the October 2021 Nor'easter (Attorney General Brief at 139). The Attorney General asserts that this proposal should be rejected because the Company has not yet provided supporting documentation or costs for Department review (Attorney General Brief at 139).

2. Company

The Company contends that storms are more common due to changes in weather patterns and climate change and are more costly due to expectations (customer and political) that compel more rapid restorations (Company Brief at 312). According to the Company, these circumstances are beyond its control and are creating an unpreventable increase in the cost of storm response (Company Brief at 312). As such, the Company requests that the Department consider the proposed modifications to the storm fund structure (Company Brief at 312-318). Further, the Company asserts that its proposal to maintain the SCRAF is in the best interest of ratepayers as it serves to minimize carrying charges that ultimately will be recovered for the storm fund qualifying events which, in turn, mitigate bill impacts and maintain stabilized rates (Company Brief at 320-323). The Company's responses to the four arguments raised by Attorney General are discussed below.

First, the Company argues that its proposal to increase the annual storm fund contribution collected through base distribution rates to $31 million does not represent a significant shift of risk to ratepayers (Company Brief at 331). Rather, the Company contends that its proposal meets the Department's objective of maintaining a sufficient reserve in the storm fund for the benefit of both the Company and its customers (Company Brief at 331). The Company further asserts that to maintain a balance between storm cost recovery and rate stability, the annual storm fund contribution collected through base distribution rates is designed to recover qualifying storm costs while eliminating rate changes (Company Brief at 331, citing Exhs. ES-STORMS-Rebuttal-1, at 22; AG 12-7).

Second, the Company argues that its proposal to recover the storm-fund-eligible event threshold of $1.3 million for each storm after the seventh storm should be approved, as it is a reasonable and an appropriate means of balancing risk and cost-sharing between the Company and its customers (Company Brief at 317-318, 330, citing Exhs. ES-STORMS-Rebuttal-1, at 14-15; DPU 20-3). The Company contends that this proposal recognizes the inevitable year-to-year variability of storm-fund-eligible events, as well as the fact that larger-scale events may occur that can exceed any number of storms that the Department would find appropriate for setting the threshold (Company Brief at 317-318). Further, the Company asserts that the proposal is symmetrical, so that if there is a deviation resulting in a lower number of storms in a year, customers would be credited with the storm-fund-eligible event threshold (Company Brief at 318). Nevertheless, the Company claims that, while fewer than six storm-fund-eligible events could occur in any given year, it is more likely that the number of storm events in any year will exceed six (Company Brief at 329).[135]

Third, NSTAR Electric argues that the Department specifically permitted the Company to propose an appropriate level of recovery associated with the storm-fund-eligible event threshold amounts for the six storm events in 2020 (Company Brief at 325-326, citing D.P.U. 21-75/D.P.U. 21-76, at 28). Further, the Company contends that allowing recovery through base distribution rates of the storm-fund-eligible thresholds for three storm events, as approved in D.P.U. 17-05, is an ineffective means of determining a representative number of storm-fund-eligible storms due to the increasing frequency and intensity of storms (Company Brief at 326-327, citing D.P.U. 17-05, at 546; D.P.U. 21-75/D.P.U. 21-76, at 22; Company Reply Brief at 48). According to the Company, the actual number of storm-fund eligible

135 The Company notes that since 2020, the number of qualifying storm fund events has exceeded the number of storm-fund-eligible event thresholds included in base distribution rates as the representative number of such storms (Company Brief at 329, citing Exhs. ES-STORMS-Rebuttal-1, at 8; DPU 20-3).

storm occurrences in a given year exceeds the number of storms the Department has historically allowed in base distribution rates (Company Reply Brief at 47). Thus, the Company asserts that there is no imbalance in allowing the recovery of storm-fund-eligible event thresholds over the representative number of storms established in D.P.U. 17-05 (Company Brief at 328). Based on these considerations, the Company seeks recovery of the storm-fund-eligible event threshold amounts for six storm events in 2020, and for seven additional storm events in 2021 (Company Brief at 327-328; Company Reply Brief at 48). The Company argues that disallowing these costs without a finding that the costs were unreasonably incurred is not an appropriate outcome (Company Reply Brief at 47).

Finally, NSTAR Electric disagrees with the Attorney General's recommendation to deny the Company's proposal to recover costs associated with Tropical Storm Henri and the October 2021 Nor'easter (Company Brief at 332, citing Attorney General Brief at 139). The Company argues that it is important to begin cost recovery of these storm events on January 1, 2024, in order to strike an appropriate balance between cost recovery and rate stability (Company Brief at 332, citing Exh. DPU 4-14). In this regard, the Company contends that a delay in recovery of these costs would create significant fluctuations in customer rates as well as significant carrying charges (Company Brief at 332, citing Exhs. DPU 4-14; AG 20-3). For these reasons, the Company asserts that the Department should approve cost recovery commencing January 1, 2024, associated with Tropical Storm Henri and the October 2021 Nor'easter (Company Brief at 332).

D. Analysis and Findings

1. Introduction

The Department's primary objective for allowing a storm fund is to levelize the recovery of storm restoration costs of major storms on ratepayers. D.P.U. 17-05, at 545; D.P.U. 15-155, at 73; Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 13 (2014), citing 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. 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. 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 the improvement of each electric utility'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 the acceptable performance for emergency preparation and restoration services for electric and gas companies); Investigation by Department of Public Utilities into Responses to Tropical Storm Irene and October 2011 Snowstorm, 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); D.P.U. 11-119-C at 71-72 (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 the Company to devote substantial resources to achieving the desired results. Further, as the Company's recent history indicates, the frequency and severity of major storms has increased (see, e.g., Exhs. ES-REVREQ-1, at 159; ES-REVREQ-2, Sch. 22, at 2 (Rev. 4); ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 11-29, Att.; AG 8-80, Att.). Not surprisingly, the costs of responding to these events have increased as well (see, e.g., Exhs. ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 8-80, Att.).

We acknowledge that NSTAR Electric's current storm fund mechanism has not provided the desired balance between cost recovery and rate stability. Specifically, the overall number of NSTAR Electric's major storm events in the past several years have contributed to a large storm fund deficit that expanded even further due to the accumulation of a significant amount in carrying charges.[136] The severity and frequency of these storms could not have been anticipated when NSTAR Electric's storm fund mechanism was developed, or when it was most recently refined in D.P.U. 17-05. As a result, without a storm fund mechanism, it is unlikely that NSTAR Electric could have absorbed the large

[136] As previously noted, the Company estimates its current storm fund deficit at $106 million (Exh. DPU 4-8, Att. (b)).

accumulation of storms costs over the past several years without filing a base distribution rate case, or even multiple rate cases, which could have resulted in an increase in rates for distribution service other than storm fund costs. Moreover, coupled with the five-year stay-out provision associated with the Department-approved PBR mechanism in the instant proceeding (see Section IV.D.5.a above), a storm fund remains an important cost recovery mechanism.[137]

Therefore, we find that, if properly structured, allowing NSTAR Electric to continue to operate a storm fund can provide for adequate recovery of storm costs in a manner that is designed to create rate stability. On that basis, we conclude that the storm fund shall continue, but with several modifications, as discussed below.

3. Storm Fund Modifications

a. Storm-Fund-Eligible Event Threshold

The Company proposes to increase the storm-fund-eligible event threshold to $1.3 million in incremental O&M costs (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162). NSTAR Electric states that its proposal is based on increasing the current threshold of $1.2 million by the cumulative inflation change of the GDP-PI, as reported by the U.S. Bureau of Economic Analysis, from 2016 through 2020 (Exhs. ES-REVREQ-1, at 163; DPU 4-7, Att.).

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137 The Department notes that the PBR mechanism does not apply to the storm-fund-eligible events or thresholds.

The Department has reviewed the Company's storm-fund-eligible event threshold calculation and finds it to be reasonable and consistent with Department precedent. D.P.U. 17-05, at 548-549; D.P.U. 18-150, at 416; D.P.U. 15-155, at 76-77. Further, we find that this increased threshold strikes an appropriate balance between providing NSTAR Electric with necessary access to the storm fund to recover costs associated with major storms and ensuring that the routine storms are not contributing to a storm fund deficit balance. Accordingly, we approve a storm-fund-eligible event threshold of $1.3 million per storm event.

b. Annual Storm Fund Contribution Collected Through Base Distribution Rates

The Company proposes to increase the annual storm fund contribution collected through base distribution rates to $31 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 181; ES-REVREQ-2, Sch. 22 (Rev. 4)). A storm fund is intended to provide 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. 17-05, at 551; D.P.U. 15-155, at 78. As evidenced by the increased frequency and magnitude of storm fund eligible storms since 2017, and the projected storm deficit balance of $106 million if the current storm fund contribution and number and magnitude of storms remained the same, the current annual storm fund contribution of $10 million has proven to be insufficient to maintain rate stability (Exhs. ES-REVREQ-1, at 159, 179-181; ES-REVREQ-2, Sch. 22, at 2 (Rev. 4); ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 11-29, Att.; AG 8-80, Att.). Thus, we conclude that an increase in the base distribution rate contribution to the storm fund is warranted. D.P.U. 18-150, at 423; D.P.U. 17-05, at 551; D.P.U. 15-155, at 178; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-85, at 101, 106 (2016); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-59 (2013).

Here, the Department seeks to set a new annual storm fund contribution amount in base distribution rates that will allow the Company to recover storm costs over time without generating a surplus or deficit balance in the storm fund that exceeds the symmetrical cap.[138] We recognize the uncertainty in achieving this result given the unpredictable nature of weather in general, and storm-fund qualifying events in particular. Further, we acknowledge that, while major historical storm events provide some perspective regarding the frequency, severity, and cost of major storms, such information is by no means sufficiently predictive with any degree of certainty to definitively plan for future storm events. Notwithstanding these considerations, however, NSTAR Electric's storm fund history is instructive in the context of developing new and updating existing elements of the storm fund.

The Department has reviewed the record supporting the proposed annual storm fund contribution by NSTAR Electric (see, e.g., Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 163-164, 181; ES-REVREQ-2, Sch. 22 (Rev. 4); ES-STORMS-Rebuttal-1, at 16-24; DPU 4-8, at 3). In its review, the Department considered the number of storms that have

[138] In D.P.U. 17-05, the Company proposed, and the Department allowed, a symmetrical cap of $30 million on the storm fund's balance to trigger either a customer refund for an over-recovery balance that exceeds the cap, or a customer charge for an under-recovery balance that exceeds the cap. D.P.U. 17-05, at 532-533, 554-555.

occurred between the Company's last rate case and the end of the test year; the incremental cost of these storms; the number of storms with incremental O&M costs that were so extraordinarily high that they should be deemed statistical outliers; and the number of storms that would not have been eligible for storm fund recovery had the $1.3 million storm-fund-eligible event been in effect (Exhs. ES-REVREQ-4, Sch. 11 & Atts.; DPU 4-8, Atts. (b), (c), (d); DPU 20-3, Att.; AG 11-29, Att.; AG 8-80, Att.). Additionally, we reviewed the calculation applied by the Company as the basis to establish its proposed $31 million annual storm fund contribution amount and find that it is consistent with the Department precedent (Exhs. ES-REVREQ-1, at 181; ES-REVREQ-2, Sch. 22 (Rev. 4)). D.P.U. 17-05, at 531, 553.

We are not persuaded by the Attorney General's argument that the Company's proposal represents a significant shift of risk to ratepayers. We find that the proposal sufficiently reflects the Company's storm fund history and as noted above, is consistent with Department precedent. Further, we conclude that increasing the annual storm fund contribution is a reasonable and appropriate approach to provide sufficient funds to levelize the rate impact for major storms that are eligible for cost recovery through the storm fund and decrease the likelihood that the storm fund will attain a large deficiency balance. Thus, contrary to the Attorney General's contention, we find that increasing the annual storm fund contribution is necessary to maintain rate stability over the long term. Accordingly, we approve the Company's proposal to increase the annual storm fund contribution collected through base distribution rates to $31 million.

c. Annual O&M Expense for Storm Events

NSTAR Electric proposes to increase the annual O&M expense associated with storm events to $7.8 million (Exh. ES-REVREQ-1, at 164-164). The Company bases this proposal on the average number of storm-fund-eligible events from 2017 through 2020, which were six events on average, multiplied by the proposed storm-fund-eligible event threshold of $1.3 million (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 164-165; AG 12-6).

As the frequency and magnitude of storm events has varied significantly year-to-year, the Department recognizes that the test-year level of O&M costs in base distribution rates is not necessarily representative of the Company's future costs. 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. The Department finds that the Company's proposed annual O&M expense of $7.8 million in base distribution rates, based upon recovery for six storm-fund-eligible events per year and applying the approved $1.3 million storm-fund-eligible event threshold, is reasonable and consistent with Department precedent. 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.

d. Recovery of Storm-Fund-Eligible Event Threshold After the Seventh Storm Event

NSTAR Electric proposes that, for each storm-fund-eligible event subsequent to the seventh storm event in a calendar year, the Company is permitted to recover the storm-fund-eligible event threshold of $1.3 million through the storm fund (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 165-166, 169-170; DPU 34-1). Conversely, if there are less than five storm-fund-eligible events in a calendar year, customers would receive a $1.3 million credit for the number of events less than five that did not occur (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 169-170; DPU 34-1).

The Department recognizes that the frequency of storm-fund-eligible storms is inherently variable year-to-year and as a result cost recovery may not align with the amounts collected through base distribution rates for a set number of storms. Nonetheless, based on the record evidence, the Department is persuaded that it is more likely than not that the number of storm-fund-eligible storms will increase in future years due to weather patterns and meteorological characteristics associated with climate change (Exhs. ES-STORMS-REBUTTAL-1, at 8; DPU 4-1). See also Inflation Reduction Act of 2022, P.L. 117-169, § 50153 (appropriating funds to address the effects of changes in weather due to climate change on the reliability and resiliency of the electric grid). Therefore, the Department agrees with the Company and finds it reasonable to establish a measure of relief in years when the number of storm-fund-eligible events significantly exceed the representative number in base distribution rates. See D.P.U. 21-75/D.P.U. 21-76, at 22. The Department, however, finds that the Company's proposal to allow it to recover storm-fund-eligible event thresholds for six events in base rates and any event after the seventh event does not appropriately balance the financial risk between the Company and ratepayers. More than one storm event above average does not constitute a significant variation from the average number of annual storms. Based on consideration of the frequency of storms, the Department finds that three storm events after above the average number of storm events is a significant variation in the reasonably anticipated number of storms. Therefore, the Company may recover storm-fund-eligible event thresholds of $1.3 million through the storm fund for each storm-fund-eligible event subsequent to the eighth storm event in a calendar year.

The Company's proposal also seeks to provide relief to ratepayers if there are fewer than five storm-fund-eligible events in a year (Exhs. ES-CAH/DPH-1, at 98; ES-REVREQ-1, at 162, 169-170; DPU 34-1). In conjunction with the above modifications, the Department finds that the Company's proposal appropriately balances the financial risk between NSTAR Electric and ratepayers. Thus, we approve this aspect of the proposal.

Based on the above considerations and findings, we approve the Company's proposal, as modified herein.

4. Other Proposals

a. Recovery of Storm-Fund-Eligible Event Thresholds for 2020 and 2021 Storms

The Company proposes to recover through the storm fund the current storm-fund-eligible threshold of $1.2 million for six storm-fund-eligible events that occurred in 2020 and seven storm-fund-eligible events that occurred in 2021, for a total of $15.6 million in costs (Exh. ES-REVREQ-1, at 173; Company Brief at 328; Company Reply

Brief at 49).[139] As noted, the Commonwealth is experiencing weather patterns and meteorological characteristics associated with climate change. See also D.P.U. 21-75/D.P.U. 21-76, at 27. When the Department established the annual O&M expense in base distribution rates in 2017, we did not anticipate that number of storm events would vary significantly from the representative amount. D.P.U. 21-75/D.P.U. 21-76, at 22. The Attorney General argues that allowance would retroactively alter the entire regulatory treatment of storm costs and storm fund cost eligibility (Attorney General Brief at 135-136). We disagree. The costs that the Company proposes to collect do not retroactively change rates provided for prior service. D.P.U. 10-70, at 216. Instead, the increased costs are due to changes in weather patterns and increased storm activity since the Company's last base distribution rate case (Exhs. ES-STORMS-REBUTTAL-1, at 8; DPU 4-1). Based on the changes that have occurred since 2017, we find it appropriate to allow the Company to recover the threshold amounts for storm-fund-eligible events that significantly exceeded the representative level in 2020 and 2021. The Department, however, finds that a deviation greater than one storm is not a significant deviation from the representative level of storms contemplated in D.P.U. 17-05. Consistent with our above

[139] In D.P.U. 21-75/D.P.U. 21-76, at 28, the Department allowed NSTAR Electric to apply deferred accounting treatment to the excess calendar year 2020 storm-fund-eligible event threshold amounts (i.e., the threshold amounts that exceed those already recovered in base rates less one) until the Company's next base rate proceeding. There was no specific deferral of the storm-fund-eligible event thresholds for the seven storm events that occurred in 2021, which the Company seeks to include in this proposal.

findings, the Department finds that a deviation of three or more storms above the representative level constitutes a significant variation that was not anticipated in the approval of the storm fund mechanism. Accordingly, the Company may recover the current storm-fund-eligible threshold of $1.2 million for five storm-fund-eligible events that occurred in 2020 and six storm-fund-eligible events that occurred in 2021, for a total of $13.2 million in costs.

b. Maintaining the Current SCRAF

NSTAR Electric proposes to maintain its current SCRAF for effect on January 1, 2023, subject to a future prudence review and reconciliation of the storm costs, to recover a portion of the Company's outstanding storm fund deficiency of approximately $106 million over a five-year period for an annual amortization amount of $21.2 million (Exhs. ES-REVREQ-1, at 178-180; DPU 4-8, Att. (b)).[140] Currently, the Company recovers an annual amortization amount of $28 million through the SCRAF for costs associated with storm-fund-eligible events that occurred prior to February 1, 2018 (Exh. ES-REVREQ-1, at 178). On December 31, 2022, the amortization period associated with these storms expires (Exhs. ES-REVREQ-1, at 178; DPU 4-14). The Company anticipates additional storm activity to occur in 2022 that would further increase the storm fund deficit

140 In its review of NSTAR Electric's 2020 SCRAF filing, the Department determined that it would review the appropriate method for cost recovery of the storm fund deficiency balance in the instant base distribution rate case. D.P.U. 20-29, Interlocutory Order on Motion for Adoption of Storm Cost Review Schedule at 9-10 (December 21, 2021).

(Exh. ES-REVREQ-1, at 179). If the Company were to reflect the current storm fund deficit amortized over five years in rates effective January 1, 2023, it estimates relatively small bill impacts (0.1 percent decrease for EMA customers and 0.6 percent increase for WMA customers) (Exh. ES-REVREQ-1, at 179). We find the Company's proposal is a reasonable and appropriate way of recovering the outstanding storm fund deficiency, subject to required prudence reviews and reconciliation, while maintaining rate stability and mitigating carrying charges. Accordingly, we allow this proposal.

c. Recovery of Storm Costs for Tropical Storm Henri and the October 2021 Nor'easter

The Company proposes to recover through the SCRAF beginning on January 1, 2024, subject to future prudence review and reconciliation, $196.2 million in exogenous costs associated with Tropical Storm Henri and the October 2021 Nor'easter (Exhs. ES-REVREQ-1, at 179-180; ES-REVREQ-4, Sch. 11(d); DPU 4-8, Att. (c); DPU 4-13). The Company proposes to recover the costs for these two storm events over a five-year period for annual amortization amount of $39.2 million (Exhs. DPU 4-8, Att. (c), at 1; DPU 4-13; DPU 4-14 & Att.). The amortization of the exogenous costs currently collected through the SCRAF expires on December 31, 2023 (Exhs. ES-REVREQ-1, at 179; DPU 4-13, at 1).

We recognize the Attorney General's concern that the Company has not yet provided supporting documentation for Department review (Attorney General Brief at 139). Nonetheless, the Department has previously allowed a company to begin recovering storm-related costs before the company has submitted finalized invoices, subject to investigation and reconciliation. See, e.g., D.P.U. 18-101, at 23-24 (allowing NSTAR Electric to begin recovery of three exogenous storms in advance of finalized costs); D.P.U. 13-59, at 1-2, 14 (allowing National Grid to replenish its storm fund subject to prudence review and reconciliation of costs associated with 14 storms); D.P.U. 09-39, at 210-212 (allowing National Grid to begin recovering 2008 winter storm costs subject to investigation and reconciliation).

We find that it is reasonable and appropriate to allow NSTAR Electric to begin cost recovery of these storm events through the SCRAF beginning on January 1, 2024, as it strikes an appropriate balance between cost recovery and rate stability. Allowing the proposal will avoid significant fluctuations in customer rates and mitigate carrying charges to customers (Exh. DPU 4-13). If the Department finds any of the costs associated with these two storm events to be imprudent, the Company must return the costs to customers with interest at the prime rate calculated from the time the costs were incurred. Thus, customers will not be harmed by the commencing of cost recovery for these two storm events beginning on January 1, 2024. Accordingly, we allow this proposal, subject to the findings herein.

d. Other Storm Fund Components

The Company does not propose any changes to the storm fund cap, carrying charges related to storm-fund-eligible and exogenous storm events, or reporting on storm events. The Department finds that these components of the storm fund shall continue consistent with the directives set forth in D.P.U. 17-05 and any subsequent Department decisions.

E. Conclusion

Based on the above findings, the Department directs NSTAR Electric to implement its storm fund with the modifications set forth herein. The modified storm fund shall apply to any storm-fund-eligible events that occur on or after January 1, 2023. The Company's outstanding storm fund balance shall be recovered consistent with the findings above. The recovery of storm-related costs for Tropical Storm Henri and the October 2021 Nor'easter will commence on January 1, 2024, as described above.

Further, the Company may recover $13.2 million through the storm fund effective January 1, 2023, which represents the current storm-fund-eligible event threshold of $1.2 million for five storm-fund-eligible events that occurred in 2020 and six storm-fund-eligible events that occurred in 2021, as discussed above. Finally, as part of its compliance filing in this proceeding, the Company shall file a revised storm cost recovery adjustment tariff consistent with the storm-related directives set forth above.

XI. VEGETATION MANAGEMENT PROGRAM

A. Introduction

The Company's current Vegetation Management Program consists of two components, the Base Vegetation Management Program ("Base VM Program") and the Resiliency Tree Work Program ("RTW Program").[141] As outlined below, the Company has proposed several

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[141] For a complete background on the Company's Vegetation Management Program see D.P.U. 17-05, at 563-591; D.P.U. 11-85-B/11-119-B; and D.T.E. 06-55.

changes to these two components and also has proposed a municipality specific hazard tree removal pilot program.

B. Base Vegetation Management Program

1. Introduction

NSTAR Electric's Base VM Program involves the management of trees along distribution lines and at substation facilities to provide a safe work environment for line workers, to allow visual and physical access to the Company's electric facilities, to prevent damage to electric equipment, and to improve reliability, shorten restoration times, and improve customer satisfaction (Exh. ES-WAV-2, at 2). The Company's service area includes two distinct geographic areas, i.e., EMA and WMA, that differ to a certain extent due to varying weather patterns, landscapes, and tree species (Exh. ES-WAV-1, at 6-7). As such, the Company does not perform the same type of work in the two geographic areas (Exh. ES-WAV-1, at 6-7).

2. Company Proposal

The Company's current Base VM Program includes an established trim cycle to ensure that all circuits, regardless of performance, are trimmed at least once every four to five years, subject to circuit-specific considerations (Exhs. ES-WAV-1, at 3; DPU 39-10, at 4). Due to the differences in the two geographic areas, the Company proposes to eliminate the requirement for a blanket four- to five-year trim cycle and, instead, prioritize circuits based on performance and reliability (Exhs. ES-WAV-1, at 14-15; DPU 39-10, at 4-6). The Company notes that information systems have evolved, and it is now able to utilize a database of tree-related outages and analysis of SAIDI/SAIFI to prioritize vegetation management resources to be used for at-risk circuits (Exh. ES-WAV-1, at 15-18).[142] NSTAR Electric also proposes to conduct pre-trim mobile visual inspections on every transmission and distribution line at least every four years to ensure that no areas of the distribution system are left unattended and, should it encounter vegetation issues, the Company would address them immediately after inspection (Exh. ES-WAV-1, at 15-16, 19). Under the Company's proposal, all circuits would be trimmed at least every eight years, regardless of inspection or reliability data (Exhs. ES-WAV-1, at 16; DPU 39-10).

The Company proposes to recover $20,007,619 through base distribution rates (Exhs. ES-REVREQ-1, at 104; ES-REVREQ-2, Sch. 21; AG 10-23). The Company based this amount on its test-year Base VM Program expenses (Exhs. ES-REVREQ-1, at 104; ES-REVREQ-2, Sch. 21; AG 10-23).

3. Positions of the Parties

The Company contends that its proposed modification will assist the Company in addressing increasing frequency of weather events caused by climate change by enhancing reliability on the system based on frequency of impact, severity, and customers served (Company Brief at 334-335). The Company asserts that not all distribution lines and circuits are created equal, as each serve different purposes and encounter unique reliability and

142 The Company uses a Power BI database to track outages on its system, to isolate and identify specific outage information as it relates to tree impacts on a circuit, and to track the number of customers impacted (Exh. ES-WAV-1, at 16; Tr. 6, at 586-589).

vulnerability issues based on the number of customers and areas served as well as the rate and severity of weather events (Company Brief at 339, citing Exhs. ES-WAV-1, at 15; ES-WAV-Rebuttal-1, at 4-6). NSTAR Electric contends that the proposed reliability-based circuit prioritization would be based on data that was not previously available, as the Company's information systems have evolved so that data as it relates to tree impacts, the number of customers impacted, and specific areas of circuits down to the street, pole, and device location are now tracked and recorded (Company Brief at 339-340, citing Exhs. ES-WAV-1, at 18; ES-WAV-Rebuttal-1, at 5-6; DPU 39-10).

In addition, the Company asserts that due to varying vegetation, some circuits in its service area have existing clearances that do not require trimming every four years, while other circuits have clearances that would benefit from more frequent trimming (Company Brief at 342, citing Exh. DPU 28-6). NSTAR Electric maintains that allowing it to trim some circuits more than once in the four-year cycle and delay other circuits until trimming is necessary, although no trim cycle would exceed eight years, would improve reliability on the system and allocate resources to ensure efficiency and cost containment (Company Brief at 342, citing Exhs. ES-WAV-1, at 5; DPU 39-10). No intervenor addressed the Company's Base VM Program proposals on brief.

4. Analysis and Findings

The Company proposes to utilize a reliability-based analysis to prioritize the circuit trim schedule but to have flexibility to do some circuits more than once in the four- to five-year trim cycle and to schedule some circuits for trim after five years, but no later than eight years (Exh. DPU 39-10, at 5). Based on the record evidence, the Department determines that using a reliability-based analysis will benefit ratepayers by improving the reliability and resiliency of the Company's distribution system (Exhs. ES-WAV-1, at 15, 17; DPU 28-6; DPU 28-9; AG 10-19, at 1-2). We recognize that technology has evolved and that the Company is now better positioned to use different data to prioritize vegetation management resources (Exhs. ES-WAV-1, at 18; ES-WAV-Rebuttal-1, at 5-6; DPU 39-10). Further, the Company has demonstrated that trees and vegetation are the leading cause of customer outages (Exhs. ES-WAV-1, at 6-7, 14, 34; ES-WAV-Rebuttal, at 22). Thus, the Company's proposed modification to focus on reliability-based prioritization inspections is likely to put NSTAR Electric in a better position to meet the Department's SQ guidelines. Revised Service Quality Guidelines, D.P.U. 12-120-D, at 7-8 (2015).

Nonetheless, the Department finds that deferring trimming for eight years may not further the objectives required for a vegetation management program. Specifically, companies are required to meet circuit performance reliability requirements that become more stringent over time. D.P.U. 12-120-D at 7-9. While the Department recognizes that some flexibility in trimming is needed, we find it appropriate to require that any trimming be deferred for no more than five years.[143]

143 As discussed in Section IV.D.5.a above, the Department has approved a PBR plan for NSTAR Electric with a five-year term, with the potential to continue the term for another five years. At the time of its next base distribution rate case filing, or request to continue the PBR term, the Company shall submit to the Department an updated reliability-based analysis, which shall include outage impacts of the tree trimming,

Finally, it is a well-established Department precedent that base distribution rate filings are based on an historic test year, adjusted for known and measurable changes. D.P.U. 10-70, at 232, 254-255; Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3-5 (1980). Here, the Company's test-year expenditure was $20,007,619 (Exhs. ES-REVREQ-2, Sch. 21, at 2; AG 10-23). Based on the record evidence, we find that the test-year expenditure is representative of the Company's spending for its Base VM Program vegetation management (Exhs. ES-REVREQ-1, at 104; ES-REVREQ-2, Sch. 21; AG 10-23). Therefore, we allow the inclusion of $20,007,619 in base distribution rates.

C. Resiliency Tree Work Program

1. Introduction

The Company's RTW Program was established as a six-year pilot program, from January 1, 2017 through December 31, 2022. D.P.U. 17-05, at 580-581.[144] The RTW Program costs are recovered on an annual basis through a reconciling mechanism, i.e., the RTW factor.[145] D.P.U. 17-05, at 583-584. The Company proposes to continue operation of the RTW Program but modify cost recovery (Exh. ES-WAV-1, at 37). Specifically, NSTAR

visual comparisons of areas trimmed frequently and less frequently to demonstrate the accuracy of the analysis, and data-based improvements to the program.

144 For additional background on the RTW Program, refer to D.P.U. 17-05, at 563-584.

145 Pursuant to the RTW Program tariff, the Company submits an RTW factor filing annually on September 15th for rates effective January 1st (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 18; ES-RDC-6, Sch. 2, at 338, 342).

Electric proposes to collect RTW Program costs from January 1, 2017 to December 31, 2022, through the RTW factor (Exh. ES-WAV-1, at 37).[146] For work performed after January 1, 2023, the Company proposes to transfer a representative level of costs into base distribution rates (Exh. ES-WAV-1, at 32, 37). Specifically, the Company's proposes to include $23.2 million in base distribution rates, which is comprised of: (1) $3.2 million for mid-cycle trimming; (2) $5.0 million for maintenance enhanced tree trimming and RTW trimming; and (3) $15.0 million for tree removals (Exhs. ES-WAV-1, at 34-35; ES-WAV-3, at 16).[147]

2. RTW Program Overview

The Company's RTW Program consists of three main components. First, the RTW Program trimming specification is applied to circuits that are considered at risk for reliability and is different from both the scheduled maintenance trim specification and the maintenance

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[146] The RTW Program costs for 2017 through 2021 are under investigation in separate dockets. NSTAR Electric Company, D.P.U. 21-108; NSTAR Electric Company, D.P.U. 20-97; NSTAR Electric Company, D.P.U. 19-114; NSTAR Electric Company, D.P.U. 18-102. The Company proposed that the Department review such costs and issue final approval of the costs in this proceeding (Exh. ES-WAV-1, at 37-38). The Department has already determined that it would not adjudicate the RTW Program costs for 2017 through 2021 in this proceeding, and we need not revisit that decision. D.P.U. 22-22, Interlocutory Order on Scope of Proceeding at 10 (March 9, 2022) ("Scoping Order"). On September 23, 2022, the Company filed its annual RTW factor for 2022. NSTAR Electric Company, D.P.U. 22-123. Therefore, 2022 RTW Program costs were not discussed on brief or in the Scoping Order.

[147] To facilitate the Department's review in the Company's next base distribution rate case, NSTAR Electric proposes to continue tracking the RTW Program activities and costs separately from the Base VM Program (Exh. ES-WAV-1, at 35-36).

enhanced tree trimming specification (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 13). The Company's experience is that the majority of tree-related outages occur from limbs and trees that are located beyond the maintained Base VM Program trim zone (Exh. ES-WAV-1, at 23). The RTW Program trimming specification expands the Base VM Program trim zone on the backbones of critical circuits to 15 feet to the side of the circuit and 25 feet above the circuit (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 13; DPU 39-10). The Company states that this enhanced trim zone helps to make circuits more resilient to tree-caused outages (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 13).

Second, the RTW Program is intended to complement the Company's Base VM Program's existing tree removal activities by expanding the identification and removal of hazard and at-risk trees beyond each circuit's backbone to include laterals serving 100 or more customers as well as off-road rights-of-way located on private property (Exhs. ES-WAV-3, at 14; ES-WAV-1, at 24; DPU 39-10). This expansion of tree removal is intended to support a reduction in the number of customers impacted by fallen trees (Exh. ES-WAV-1, at 24).

Third, mid-cycle trimming[148] is an element in the Company's strategy to address emerging poor-performing circuits (Exhs. ES-WAV-1, at 24; DPU 39-10). The Company

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148 As outlined in Section XI.B.2 above, the Company currently follows an established trim cycle to ensure that all circuits are trimmed at least once every four to five years (Exh. ES-WAV-1, at 3). Mid-cycle (or off-cycle) trimming is trimming that occurs earlier than the established trim cycle and is taken on a proactive basis to address poor-performing circuits and other anomalies (Exh. ES-WAV-1, at 3).

stated that mid-cycle trimming provides the flexibility to address immediate issues on circuits that are not scheduled for trimming under the Base VM Program (Exh. DPU 39-10). The Company states that mid-cycle trimming is also consistent with the Department's reliability directive to trim all circuits at least once every five years (Exhs. ES-WAV-1, at 24; ES-WAV-3, at 14, citing D.P.U. 11-85-B/11-119-B at 135).

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Department should reject the Company's request to continue the RTW Program (Attorney General Brief at 141). The Attorney General maintains that the RTW Program was not approved to extend beyond six years (Attorney General Brief at 139). Moreover, the Attorney General asserts that the RTW Program, which has been in effect for five of the six planned years, should have already accomplished most of its intended goals to improve reliability and expand the clearance specifications for circuits classified as at risk (Attorney General Brief at 140, citing NSTAR Electric Company, D.P.U. 21-108, Exh. ES-WAV/RWF-1, at 12).

In addition, the Attorney General asserts that felled trees removed through the RTW Program will not re-emerge as vegetation management issues (Attorney General Brief at 10). Further, the Attorney General maintains that while vegetation will continue to grow, it should be manageable through the Company's Base VM Program on an approved trim cycle (Attorney General Brief at 140). In addition, the Attorney General contends that continuation of the RTW Program creates redundancy of vegetation services (Attorney General Brief at 140-141). Specifically, the Attorney General asserts that an augmented vegetation management plan, such as the RTW Program, targets the Company's entire distribution system resulting in multiple crews targeting the same circuits (albeit with different trim specifications) and yielding operational redundancies and unwarranted vegetation management costs (Attorney General Brief at 140-141).

Finally, the Attorney General recommends that the Department reject the Company's proposal to transfer $23.2 million of RTW Program costs to base distribution rates (Attorney General Brief at 141, citing Exh. ES-WAV-1, at 3, 34-35). The Attorney General notes that the Department approved the recovery of RTW Program costs for 2017 through 2021 subject to further investigation and reconciliation, and that such further investigation has not yet concluded (Attorney General Brief at 141-142, citing D.P.U. 21-108, at 4; NSTAR Electric Company, D.P.U. 20-97, at 4; NSTAR Electric Company, D.P.U. 19-114, at 4; NSTAR Electric Company, D.P.U. 18-102, at 4).

b. Company

The Company asserts that the costs and benefits of its RTW Program are well-established and that it has become an integral part of the Company's overall Vegetation Management Program (Company Brief at 356). The Company highlights four key areas of system improvement arising from the RTW Program, based on a comparison of a three-year average baseline to data from the six-month period from January 2021 to June 2021 (Company Brief at 353-355). The Company asserts that the first area of improvement is customers affected by tree-related outages (Company Brief at 354). Specifically, NSTAR

Electric maintains that the total number of customers affected by tree-related outages declined by 28 percent (Company Brief at 353-354, citing Exh. ES-WAV-1, at 30). Similarly, the Company contends that RTW Program circuits had a 54-percent reduction in tree-related outages as compared to a 17-percent reduction for the non-RTW Program circuits (Company Brief at 354, citing Exh. ES-WAV-1, at 30).

NSTAR Electric contends that the second area of improvement is contributions to SAIDI by tree-related outages (Company Brief at 354). Specifically, the Company asserts that SAIDI tree-related outages on RTW Program circuits decreased by 65 percent as compared to a 32-percent decrease in SAIDI tree-related outages on non-RTW Program circuits (Company Brief at 354, citing Exh. ES-WAV-1, at 30).

The Company claims that the third area of improvement is contributions to SAIFI by tree-related outages (Company Brief at 354). NSTAR Electric asserts that SAIFI associated with tree-related outages on RTW Program circuits decreased 56 percent as compared to an 18-percent reduction in SAIFI tree-related outages on non-RTW Program circuits (Company Brief at 354, citing Exh. ES-WAV-1, at 30-31).

The Company contends that the fourth improvement is a reduction in the number of outages on RTW Program circuits as compared to non-RTW Program circuits (Company Brief at 354). The Company maintains that the RTW Program circuits experience a 40-percent reduction, while the non-RTW Program circuits experienced a nine-percent increase (Company Brief at 354-355, citing Exh. ES-WAV-1, at 31). NSTAR Electric asserts that, based on these results, the RTW Program provides numerous benefits to its overall distribution system by minimizing tree-related outages and improving the customer experience (Company Brief at 355).

In addition, the Company asserts that the RTW Program has yielded benefits of noticeably fewer customer interruptions, a more stable resource of crew availability, and assurance that NSTAR Electric's ongoing grid modernization efforts are not hampered by hazard trees (Company Brief at 355-356, citing Exh. ES-WAV-1, at 31-32). The Company also argues that there is a critical need to continue the RTW Program due to the increasing frequency and severity of weather-related events in NSTAR Electric's service territory (Company Brief at 356). Further, the Company maintains that while trees felled through the RTW Program may not re-emerge as vegetation management issues in the immediate future, other hazard and risk trees will appear, e.g., due to drought, insect infestation, tree species (Company Brief at 363-364).

Further, the Company maintains that contrary to the Attorney General's assertion, the RTW Program is not redundant to the Base VM Program and the reliability benefits may not continue in the absence of the RTW Program (Company Brief at 361, 364, citing Exhs. ES-WAV-1, at 23-24; ES-WAV-Rebuttal-1, at 14-18; DPU 39-10). The Company highlights the circuit trimming specifications and notes that they are distinct from those in the Base VM Program in terms of required clearance (Company Brief at 364, citing Exhs. ES-WAV-1, at 23-24; ES-Rebuttal-1, at 17; DPU 39-10; DPU 66-4).

With respect to its proposal to transfer the RTW Program costs to base distribution rates, the Company asserts that the costs of the RTW Program are stable and therefore representative of future costs (Company Brief at 358, citing Exhs. ES-WAV-1, at 32; DPU 39-10). The Company maintains that it was authorized to recover $23.2 million annual incremental RTW Program O&M expenses and that it has utilized this amount to accomplish the goals of the RTW Program (Company Brief at 358, citing Exhs. ES-WAV-3; DPU 39-10). In addition, the Company maintains that continuing recovery of the RTW Program costs through the annual reconciling mechanism adds an administrative burden to Company personnel as employees assigned to work on the RTW Program are also required to conduct that program's administrative review (Company Brief at 366, citing Exhs. ES-WAV-1, at 32-33; ES-WAV-Rebuttal-1, at 18; AG 10-21).

4. Analysis and Findings

a. Continuation of RTW Program

The Department has recognized the significant financial burden that ratepayers have borne due to high storm restoration costs. The Department has further recognized that a company's poor pre-storm preparation may have adverse effects on that company's ratepayers. D.P.U. 13-90, at 19; D.P.U. 11-01/D.P.U. 11-02, at 70-71; D.P.U. 09-39, at 210-211. Thus, the Department views storm resiliency programs, such as the RTW Program, as a potentially worthwhile step towards strengthening a utility's distribution system and mitigating a portion of the physical damage and financial impacts of future storm events, and thereby benefitting ratepayers. D.P.U. 13-90, at 19. It is for these reasons that the Department allowed the RTW Program on a pilot basis. D.P.U. 17-05, at 580-581.

The Department concludes that the Company has demonstrated that the RTW Program, in conjunction with the Base VM Program, has been beneficial to further reducing storm-related outages through resiliency tree work outside of the Base VM Program trim zone (Exhs. ES-WAV-1, at 30-31; DPU 39-10). Further, there are differences between the Base VM Program and the RTW Program that highlight the uniqueness of each program (Exhs. ES-WAV-1, at 23-24; ES-WAV-Rebuttal-1, at 14). For example, the specific trim zones differ for the Base VM program and the RTW Program (Exh. ES-WAV-1, at 23-24). Further, the RTW Program offers elements of tree work not considered standard practice under the Base VM Program (e.g., enhanced mid-cycle trimming, expanded hazard and risk-tree identification and removal) (Exh. ES-WAV-1, at 24).

In addition, while trees removed through the RTW Program may not reemerge as vegetation management issues in the immediate future, it is apparent that other trees will experience damaging conditions necessitating their removal through the RTW Program (Exh. ES-WAV-Rebuttal-1, at 14-15). In this regard, there are typically multiple hazard tree profile lists for different circuits, which are prioritized by circuit reliability, general condition of the hazard trees, availability of equipment needed depending on the type and size of the tree, and cost implications (Exhs. ES-WAV-1, at 24-25; ES-WAV-Rebuttal-1, at 12). Therefore, we find that continuation of the RTW Program is appropriate to achieve increased reliability (Exhs. ES-WAV-Rebuttal-1, at 14-16; DPU 66-18). For these reasons, the Department allows the RTW Program to continue through the PBR term.

b. RTW Program Cost Recovery

The Company proposes to collect $23.2 million annually through base rates for RTW Program expenses (Exhs. REV-REQ-1, at 104; ES-REVREQ-2, Sch. 21, at 2; ES-WAV-3, at 16). The investigation of the RTW Program costs for 2017 through 2021 is ongoing in separate dockets. D.P.U. 21-108; D.P.U. 20-97; D.P.U. 19-114; D.P.U. 18-102. Thus, the RTW Program costs are neither known nor measurable. Therefore, the Company is unable to establish an appropriate level of costs to include in base distribution rates. We also note that there has been some volatility in the costs, with costs in only calendar year 2021 exceeding the proposed $23.2 million (Exh. AG 10-22).[149]

Based on these factors, the Department disallows the Company's request to move the RTW Program costs into base distribution rates. Instead, any costs incurred for the RTW Program from January 1, 2023, will continue to be collected through the RTW factor. The Company is directed to continue submitting annual filings demonstrating its RTW Program costs.[150] Therefore, the Department will remove $23.2 million from the Company's proposed cost of service (Exh. ES-REVREQ-2, Sch. 21, at 2 (Rev. 4); Department

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149 The Company reports incurring the following annual RTW Program costs: $2,875,000 in 2017, $20,629,368 in 2018, $19,296,574 in 2019, $21,249,610 in 2020, and $23,404,894 in 2021 (Exh. AG 10-22).

150 Pursuant to the RTW Program tariff, the Company submits an RTW factor filing annually on September 15th for rates effective January 1st (Exhs. ES-WAV-1, at 23; ES-WAV-3, at 18; ES-RDC-6, Sch. 2, at 338, 342). The RTW Program tariff will remain in effect, and the Company is directed to continue submitting its annual RTW factor filings pursuant to this schedule.

Schedules 2, 9 below). The Company shall file a revised RTW Program tariff consistent with these findings.

c. Future Filing Requirements

The Department has directed NSTAR Electric to track and maintain necessary information related to its RTW Program, including, but not limited to, costs, benefits, and contribution to reliability improvements (Exh. ES-RDC-6, Sch. 2, at 342). D.P.U. 17-05 at 581-582. Given that the Department is allowing the RTW Program to continue, we find it appropriate to require certain documentation to be submitted in the Company's annual filings. Specifically, the Company's annual filings shall include information about circuits and circuit segments (i.e., circuit identifier, circuit type, circuit voltage, three-phase miles, two-phase miles, single-phase miles, total circuit miles, municipality name(s)), program work and activity by circuit and circuit segments[151] and cost information (i.e., tree removal costs, trimming costs, other costs if applicable, tree contractors, trimming contractors, contractors for other work performed).

Further, all invoices submitted by the Company shall provide detailed work descriptions and locations and should be clearly attributable to the RTW Program, i.e., differentiated from work done pursuant to the Base VM Program. In addition, the

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151 For tree work, the Company should provide whether a profile was conducted, the primary reason(s) for initiating work, work performed, trees removed, tree contractor, tree removal cost, and cost per tree removal. For trimming work, the Company should provide circuit miles planned for trimming, primary reason for initiating work, work performed, actual circuit miles trimmed, percent of planned work complete, total pruning cost, and cost per mile for trimming.

Company's annual filing shall include separate spreadsheets detailing: (1) future year planned work by circuit, including circuit priority; (2) a report on revisions of the previously planned work for the current year, i.e., reprioritization based on circuit and SQ data; (3) data on circuit improvements (customers affected, outage events, improved restoration times, etc.) as a three-year average, current year, and variance; (4) service-quality data information by system and circuit as a three-year average, current year, and variance; and (5) worst-performing three-phase circuits (i.e., bottom 25 percent of circuits, including circuit average interruption duration index ("CKAIDI"), circuit average interruption frequency index ("CKAIFI"), and circuit interruption, reported as a three-year average, current year, and variance).

D. Municipal Hazard Tree Removal Pilot Program

1. Introduction

The Company proposes a new pilot program, the municipal hazard tree removal pilot program, to begin January 2023 (Exhs. ES-WAV-1, at 4, 20; ES-RDC-6, Sch. 1, at 527; DPU 28-19). NSTAR Electric states that the current process to remove hazard trees near the distribution system takes significant time because the Company is required to obtain the requisite municipal permissions, which is a costly process when done on a state-wide basis (Exhs. ES-WAV-1, at 20; DPU 28-10). For its proposed pilot program, the Company states it would partner with municipalities to conduct surveys, identify multiple hazard tree removals, develop municipality-specific removal plans, and expedite the commissioning and approval process on a much larger scale (Exhs. ES-WAV-1, at 20-21; DPU 39-10, at 6).

The Company states its arborists would work directly with municipal tree wardens to identify hazard trees and jointly finalize a removal list (Exh. DPU 57-12).

The Company proposes to rank municipalities based on: (1) those municipalities that are willing to work with the Company to achieve more removals; and (2) those municipalities having a SAIDI/SAIFI reliability measure that is one of the 40 worst in Massachusetts (Exhs. DPU 28-10; DPU 57-12, Att.). The Company would then submit the municipal plans to the Department with cost-benefit analyses for informational purposes so that the Department is aware of the municipalities involved (Exh. ES-WAV-1, at 21).

The Company estimates an annual total cost of $1 million for the proposed pilot program (Exhs. ES-WAV-1, at 21; AG 10-17). The Company estimates an average tree removal cost of $1,000, and states that the $1 million budget would allow it to remove 50 hazard trees in 20 municipalities each year, at a cost of $50,000 per municipality (Exhs. ES-WAV-1, at 21; AG 10-17). The Company proposes to recover the costs of the proposed pilot program through the RTW factor rather than base distribution rates because the costs will be variable and unpredictable until the program matures (Exhs. ES-WAV-1, at 4, 22; ES-RDC-6, Sch. 2, at 341). The Company proposes to provide actual costs with supporting invoices for recovery through the RTW factor (Exhs. ES-WAV-1, at 22; DPU 28-20 & Att. at 3; AG 10-17).

2. Positions of the Parties

a. Attorney General

The Attorney General asserts that the Company failed to provide sufficient details regarding the proposed municipal hazard tree removal pilot program (Attorney General Brief at 142-143). In particular, the Attorney General maintains that the Company failed to provide annual pilot program costs (Attorney General Brief at 143). The Attorney General also argues that the removal of hazardous trees is already part of the RTW Program and that the Company failed to explain why this pilot program is not redundant (Attorney General Brief at 142-143). In addition, the Attorney General questions why a partnership with municipal tree wardens and municipal officials has not already been forged through the Company's Vegetation Management Program (Attorney General Brief at 143). Finally, the Attorney General contends that the Company has claimed that the pilot would reduce the amount of money needed for removal of certain hazard and risk trees, but that NSTAR Electric has not reflected such a reduction in its request to move RTW Program costs into base distribution rates (Attorney General Brief at 143, citing Exh. AG 10-16, at 1; Tr. 6, at 549).

b. Company

The Company asserts that it is requesting $1 million for this pilot program because that proposed annual budget would allow it to work with up to 20 individual municipalities annually to develop a town-specific plan to remove up to 50 hazard trees (as opposed to up to three trees over 20 years) (Company Brief at 368, citing Exhs. ES-WAV-1, at 21-22;

ES-WAV-Rebuttal-1, at 22; AG 10-17). The Company maintains that it cannot provide a more precise estimate of the costs because municipality participation is out of the Company's control, and for that reason, it proposes to report to the Department more precise costs and estimates with a cost-benefit analysis once the municipal hazard tree removal pilot program is underway (Company Brief at 368, citing Exhs. ES-WAV-1, at 21; DPU 28-8; DPU 39-10; DPU 39-14; AG 10-16).

In addition, the Company contends that the proposed pilot program is not redundant with its Base VM Program or the RTW Program because under those programs, the Company does not have the budget to accommodate broad municipal-specific plans and only removes one or two trees at a time in any given municipality, over many years (Company Brief at 369, citing Exhs. ES-WAV-1, at 20; ES-WAV-Rebuttal-1, at 22; DPU 28-8). Further, the Company argues that the proposed pilot program will result in hazard tree removals that are in addition to the trees that will be removed under the existing RTW Program (Company Brief at 369, citing Exhs. ES-WAV-Rebuttal-1, at 22; DPU 28-10).

Finally, the Company asserts it has established relationships with municipal tree wardens and municipal officials and that these relationships are stable and constantly developing (Company Brief at 369-370, citing Exhs. ES-WAV-1, at 20; ES-WAV-Rebuttal-1, at 22; DPU 28-8). The Company argues that the issue is not the relationship, but rather that the Company does not have the resources to assign crews to specific municipalities to focus on hazard tree removal (Company Brief at 370, citing Exhs. ES-WAV-1, at 20; ES-WAV-Rebuttal-1, at 22; DPU 28-8). The Company asserts that a larger-scale municipal hazard tree removal program would have a significant impact on reliability and resiliency and reduce storm damage and costs (Company Brief at 370, citing Exhs. ES-WAV-Rebuttal-1, at 23; DPU 28-8).

3. Analysis and Findings

While we acknowledge the importance of NSTAR Electric's goal of reliability and resiliency for its customers, we have several concerns with the pilot program as proposed. For example, the Company is already obligated to work with municipal officials and municipal tree wardens to remove hazard trees on public property. G.L. c. 87, § 14; D.P.U. 11-85-B/11-119-B at 122, 134; Investigation of Emergency Plans for Hurricane Bob, D.P.U. 91-228, at 12 (1992). General Laws c. 87, § 14, outlines requirements and timeframes for companies' coordination with municipal officials and municipal tree wardens. The Department has also directed companies to conduct annual meetings with local tree wardens in each municipality within their service areas. D.P.U. 11-85-B/11-119-B at 122, 134; D.P.U. 91-228, at 12.

In addition, the Department has approved continuation of the RTW Program (see Section XI.C.4.a above). The RTW Program and the Base VM Program both encompass resiliency tree removal activity, which uses the same criteria as the proposed municipal hazard tree pilot program (Exhs. ES-WAV-3, at 12; AG 10-16). Specifically, all three programs identify hazard trees to be removed by focusing on trees causing a pattern of interruptions (Exhs. ES-WAV-1, at 20-21, 25-26, 28; ES-WAV-3, at 12, 14; DPU 39-10, at 6; AG 10-16, at 1). The Company distinguishes the proposed pilot program from the

RTW Program by noting that the RTW Program is typically used to remove a single tree in a municipality (Exh. DPU 28-10). While the Company states it lacks the resources to accommodate municipal-specific plans, there is nothing in the RTW Program that prevents NSTAR Electric from focusing on specific municipalities where there are demonstrated reliability issues to harden the distribution system (Exh. ES-WAV-3, at 13-15). Further, an objective of the RTW Program is to conduct tree trimming and remove hazardous or at-risk trees, so working with municipalities focused in specific geographical areas with reliability issues in parallel with the standard Base VM Program could achieve the objects of the programs and minimize costs (Exh. ES-WAV-3, at 14, 16).

Further, NSTAR Electric acknowledged that it was unable to provide a concrete cost estimate and that it has not yet developed a budget (Exhs. ES-WAV-1, at 22; DPU 28-19). While the Company anticipates that the pilot program "should" improve the performance of circuits, it was also unable to provide an estimate of any such improvement (Exh. DPU 28-9). Given the speculative nature of the costs and any improvements, it would be premature to allow recovery of any costs related to a municipal hazard tree pilot program at this time.

In addition, the Department has granted a five-year PBR (see Section IV.D.5.a above), and, as such, the Company should have the incentive to continue to improve its RTW Program, including designing better methods to manage municipal tree removals more efficiently. Moreover, the Department notes that approval of the municipal hazard tree removal pilot program would also create an administrative burden on the Department, the Attorney General, and other intervenors.

Based on these factors, the Department finds that the recovery of costs related to the proposed municipal hazard tree removal pilot program is not in the interest of the ratepayers. Therefore, the Department disallows any cost recovery related to the proposed municipal hazard tree removal pilot program. The Company shall file a revised RTW Program tariff consistent with these findings.

XII. EXOGENOUS COST PROPERTY TAX PROPOSALS

A. Introduction

NSTAR Electric seeks to recover incremental property tax expenses resulting from cities and towns in the Company's service area adopting a hybrid "reproduction cost new less depreciation" ("RCNLD") and net book value ("NBV") method[152] of assessing the value of personal property. The Company requests recovery through two separate exogenous cost provisions. First, the Company seeks to recover $8,314,371 in total property taxes assessed by Springfield for fiscal years 2012 through 2015 under the exogenous cost provision of a settlement reached in docket NSTAR/Northeast Utilities Merger, D.P.U. 10-170-B (2012) (Exhs. ES-REVREQ-1, at 182, 184-185, 190-191; ES-REVREQ-6(a), Sch. 1). Second, the

[152] The hybrid RCNLD/NBV method is based on 50 percent of RCNLD valuations and 50 percent of NBV valuations (Exh. ES-REVREQ-1, at 135). The hybrid RCNLD/NBV method uses the property tax expense as reported on the town's most recent property tax bills, adjusted to recognize any changes in personal property valuations (Exh. ES-REVREQ-1, at 135).

Company seeks to recover $30,006,340 in property taxes attributable to fiscal years 2021 and 2022 and half of fiscal year 2023, through the exogenous cost provision of the Company's current PBR mechanism (Exhs. ES-REVREQ-1, at 182, 191-199; ES-REVREQ-6(a), Sch. 2 (Supp.); DPU 16-1 (Rev.)). The Department will address each of these requests separately below.

B. Merger Settlement

1. Introduction

In D.P.U. 10-170-B at 2, 107, the Department approved a proposed settlement ("Merger Settlement") to merge NSTAR Electric and NSTAR Gas, along with their parent holding company NSTAR, and the former WMECo, along with its parent holding company Northeast Utilities.[153] As part of its decision, the Department approved a rate freeze applicable to the base distribution rates of NSTAR Electric, NSTAR Gas, and WMECo, so that base distribution rates in effect on January 1, 2012, remained in place until January 1, 2016. D.P.U. 10-170-B at 18-19, 107.

Pursuant to Article II (5) of the Merger Settlement, NSTAR Electric may seek exogenous cost recovery of incremental property taxes incurred during the rate freeze (i.e., January 1, 2012 through December 31, 2015) associated with the adoption by municipalities of the hybrid RCNLD/NBV method of assessing the value of personal property, provided that the incremental expense meets the minimum annual threshold for

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153 Pursuant to 220 CMR 1.10(3), the Department incorporates by reference the Merger Settlement filed and approved in D.P.U. 10-170-B.

exogenous costs. The Merger Settlement provides that the dollar threshold for qualification as an exogenous factor in any calendar year covered by the Merger Settlement shall be determined by multiplying the total distribution revenues of that year by a factor of 0.003212 (Merger Settlement, Art. II (5)). The Merger Settlement is silent with respect to the method to be used to recover exogenous costs.

In D.P.U. 17-05, the former WMECo first sought to recover the aforementioned incremental property taxes assessed by Springfield as an exogenous cost pursuant to the Merger Settlement. D.P.U. 17-05, at 521-522.[154] At the time, WMECo had filed appeals of the Springfield tax assessments to the Appellate Tax Board, which still were pending. D.P.U. 17-05, at 523-524. As such, the Department denied WMECo's request to recover incremental property taxes pursuant to the Merger Settlement. The Department determined that because WMECo still was engaged in the appeals process after the denials of its tax abatement requests, we were unable to assess whether at the end of the appeals process there would be any incremental taxes and, if so, whether the amounts would be above the annual threshold subject to recovery from ratepayers as exogenous costs. D.P.U. 17-05, at 524. Thus, the Department decided not to consider WMECo's request for recovery of incremental property taxes as an exogenous cost at that time, and instead determined that, once all

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154 Springfield had transitioned to the hybrid RCNLD/NBV well before March 26, 2019, the date that the Department of Revenue issued a Local Finance Opinion detailing a change in guidance from the Bureau of Local Assessment on the appropriate method of valuation for purposes of local property tax assessment (Exhs. ES-REVREQ-1, at 184; DPU 54-5, at 1). The Local Finance Opinion is discussed further in Section XII.C.3 below.

appeals were exhausted, WMECo should file a separate petition seeking exogenous cost recovery of any incremental property tax assessed using the hybrid RCNLD/NBV method from 2012 through 2015. D.P.U. 17-05, at 524.

2. Company Proposal

In the instant case, NSTAR Electric renews the former WMECo's previous request to recover $8,314,371 in incremental property taxes from 2012 through 2015 pursuant to the Merger Settlement (Exhs. ES-REVREQ-1, at 184-185; ES-REVREQ-6(a), Sch. 1). The Company proposes to amortize the property tax recovery over a five-year period at an annual amount of $1,662,874 (Exhs. ES-REVREQ-1, at 190; ES-REVREQ-2, Sch. 26 (Rev. 4)). NSTAR Electric argues that the annual amount of incremental property taxes meets the exogenous cost recovery standard under the Merger Settlement and that all of the Company's appeals have been exhausted (Company Brief at 301-302). No intervenor specifically addressed the Company's proposal on brief.

3. Analysis and Findings

Since the Department's decision in D.P.U. 17-05, the Company's challenges to the Springfield incremental tax assessments have been unsuccessful. In particular, in May 2020, the Appellate Tax Board rejected WMECo's appeals of the 2012 and 2013 assessments. Western Massachusetts Electric Company v. Board of Assessors of the City of Springfield, Appellate Tax Board, Docket Nos. F315550, F319349 (May 20, 2020). That decision subsequently was upheld by the Massachusetts Appeals Court in a Rule 23.0 Memorandum and Order issued in April 2022. Western Massachusetts Electric Company v. Board of

Assessors of Springfield, 100 Mass. App. Ct. 1131 (Mass. App. Ct. 2022). In June of this year, the Supreme Judicial Court denied further appellate review of the matter. Western Massachusetts Electric Company v. Board of Assessors of Springfield, FAR-28794, 2021-P-0596 (June 2, 2022). Following the Appeals Court decision, the Company paid the outstanding tax liability to Springfield, including interest (Exhs. DPU 54-8, at 2 & Att.; AG 12-18).[155]

Further, since the decision in D.P.U. 17-05, the Department has had another opportunity to evaluate a request for exogenous cost recovery pursuant to the Merger Settlement. In D.P.U. 19-120, at 326-328, NSTAR Gas requested recovery pursuant to the Merger Settlement of incremental property tax expenses assessed by the City of Worcester and Town of Westborough from 2012 through 2015. In that Order, the Department determined that that NSTAR Gas did not need to exhaust all of its appeals before seeking exogenous cost recovery of incremental property taxes pursuant to the Merger Settlement and could begin to recover incremental property taxes associated with Worcester and Westborough for 2012 through 2015. D.P.U. 19-120, at 334-335.

The Department has given careful consideration to NSTAR Electric's request in the instant case. The Merger Settlement expressly allows the Company to seek recovery of the incremental tax amounts associated with the change in property valuation for fiscal years

155 The Company's instant request to recover $8,314,371 in incremental property taxes assessed by Springfield for fiscal years 2012 through 2015 does not include an interest component (Exhs. DPU 54-1, Att.; DPU 54-8, at 2).

2012 through 2015, provided that the incremental expense satisfies the Department's exogenous cost standard in D.P.U. 96-50 (Phase I) and meets the minimum annual threshold for exogenous costs set forth in the Merger Settlement (Merger Settlement, Art. II (5)). We find that the incremental tax amounts satisfy the Department's exogenous cost standard and that the Company has demonstrated that for each fiscal year from 2012 through 2015, the amount of incremental property tax exceeded the Merger Settlement threshold (Exhs. ES-REVREQ-6(a), Sch. 1; DPU 54-1, Att.). D.P.U. 96-50 (Phase I), at 292. Further, in light of the treatment of the hybrid RCNLD/NBV method by the Massachusetts appellate courts, and consistent with our decision with respect to NSTAR Gas in D.P.U. 19-120, we find that the Company no longer needs to pursue additional appeals before seeking exogenous cost recovery of incremental property taxes pursuant to the Merger Settlement.[156] Rather, we conclude that it is reasonable and appropriate for the Company to begin to recover the incremental property taxes associated with Springfield for fiscal years 2012 through 2015.

The Merger Settlement does not describe the manner in which these costs shall be recovered (see Merger Settlement, Art. II (5)). As noted above, NSTAR Electric proposes to amortize the recovery of $8,314,371 in incremental property taxes over five years at an

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[156] While the Company refers to its appeals as "exhausted," we note that the recent decision of the Massachusetts Appeals Court appears confined to the Springfield incremental tax assessments for fiscal years 2012 and 2013 (Exh. DPU 54-7, Att. (a) at 2). Nonetheless, based on the considerations above, the Company may begin to recover the entire amount attributable to fiscal years 2012 through 2015.

annual amount of $1,662,874 (Exhs. ES-REVREQ-1, at 184-185, 190; ES-REVREQ-6(a), Sch. 1; ES-REVREQ-2, Sch. 26 (Rev. 4)). In Section IV.D.5.a above, the Department approved a PBR plan for NSTAR Electric with a five-year term. As such, the Department finds that it is reasonable and appropriate to amortize the recovery of the incremental property taxes over the same term as the PBR plan. D.P.U. 19-120, at 337. To the extent the Company recovers any or all of the incremental property taxes relative to fiscal years 2012 through 2015 as a result of an abatement/appeals process, it shall refund customers the incremental property tax amounts through the exogenous cost provision of its PBR plan (Exhs. ES-REVREQ-1, at 190-191; DPU 54-2). D.P.U. 19-120, at 337.

Based on the above considerations, the Department approves the Company's exogenous cost property tax proposal relative to the Merger Settlement. The Company shall amortize the recovery of $8,314,371 in incremental property taxes over five years at an annual amount of $1,662,874.

C. D.P.U. 17-05 PBR Mechanism

1. Introduction

In D.P.U. 17-05, at 370-414, the Department approved a PBR mechanism with a five-year term, which allows NSTAR Electric to adjust its distribution rates annually through the application of a revenue-cap formula that accounts for, among other factors, inflation and exogenous events, either positive or negative. D.P.U. 17-05, at 381-399. Since the decision in D.P.U. 17-05, the Department has approved four annual PBR adjustments for the Company. NSTAR Electric Company, D.P.U. 21-106 (2021); NSTAR Electric Company, D.P.U. 20-96 (2020); NSTAR Electric Company, D.P.U. 19-115 (2019); D.P.U. 18-101. In NSTAR Electric's most recent annual PBR adjustment filing, D.P.U. 21-106, the Company included, for the first time, a request to recover $11.8 million in additional property taxes incurred in fiscal year 2021 (i.e., July 2020 through June 2021) through the end of calendar year 2021 and associated with what the Company maintained was an exogenous event resulting from a change in the valuation method used by certain municipalities to assess utility property. D.P.U. 21-106, at 3, citing Exhs. ES-RWF/ANB at 15-22; ES-RWF-ANB-1, at 1-2; ES-RDC-1, Sch. 2; see also D.P.U. 21-106, Exhs. ES-RWF/ANB-3, at 1; DPU 2-1. Subsequently, the Company proposed to remove these costs from the PBR adjustment and, instead, file a future request for exogenous cost recovery in a separate proceeding. D.P.U. 21-106, at 11, citing NSTAR Electric Filing Letter at 1-2; Exhs. ES-RWF/ANB-1 (Mitigated); DPU 2-2, Att. (a)). The Department approved NSTAR Electric's proposal, and we noted that we would review any request for exogenous cost recovery in a separate proceeding to be filed by the Company. D.P.U. 21-106, at 11.

In the instant proceeding, NSTAR Electric's initial filing included a request to recover $30,006,340 in total additional property taxes though the exogenous cost provision of the Company's current PBR mechanism, comprised of the incremental property taxes that initially were presented in D.P.U. 21-106 and subsequently withdrawn, plus incremental property taxes attributable to fiscal year 2022 and half of fiscal year 2023 (Exhs. ES-REVREQ-1, at 182, 191-199; ES-REVREQ-6(a), Sch. 2, at 1 (Supp.); DPU 16-1, Att. at 1 (Rev.)). The Company proposed to begin recovering approximately $8 million attributable to fiscal year 2021 property taxes through the PBR adjustment factor for effect on January 1, 2023 (Exh. ES-REVREQ-1, at 197). The Company stated that any over/under recovery of the prior-period expenses would be reconciled in the next PBR adjustment filing on September 15, 2023, with carrying charges calculated at the prime rate (Exh. ES-REVREQ-1, at 197).

On September 23, 2022, the Company submitted its revised fifth annual PBR filing pursuant to the PBR plan approved in D.P.U. 17-05. The Department docketed the matter as D.P.U. 22-120. In that filing, the Company does not propose a PBR adjustment to base distribution revenues. NSTAR Electric Company, D.P.U. 22-120, Exhs. ES-RDC, at 3; ES-ANB-1, at 1. Rather, NSTAR Electric proposes to recover through base distribution rates, the incremental property taxes incurred in fiscal year 2021, 2022, and the first half of 2023, which the Company states amounts to $30,187,653. D.P.U. 22-120, Exhs. ES-ANB at 7-8, 21-30 (Rev.); DPU 4-3, Att. The Company makes essentially the same statements in that filing to support its requested recovery as in the instant case. D.P.U. 22-120, Exh. ES-ANB at 15, 21-30 (Rev.).[157] The Company also requests that the Department make

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157 The Company attributes the higher amount requested for recovery in D.P.U. 22-120 to final property tax information from two municipalities that was not available at the time that exhibits were prepared in the instant case, and to a recalculation of totals to conform to the Department's recent decision in Eversource Gas Company of Massachusetts, D.P.U. 22-122 (October 31, 2022) and NSTAR Gas Company, D.P.U. 22-121 (October 31, 2022). D.P.U. 22-120, Exhs. DPU 1-1, at 4; DPU 4-3 & Att.

a finding in the instant case that an exogenous event has occurred pursuant to the PBR plan approved in D.P.U. 17-05, and then to allow the actual implementation of the cost recovery in D.P.U. 22-120. D.P.U. 22-120, Exhs. ES-ANB at 7-8 (Rev.); DPU 1-1, at 1-2.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should deny the Company's proposal to treat increased property valuations as exogenous costs under the Company's current PBR plan (Attorney General Brief at 180; Attorney General Reply Brief at 31). The Attorney General contends that none of the incremental costs associated with various municipalities using a hybrid RCNLD/NBV method meet the exogenous cost threshold set forth in the Company's PBR mechanism (Attorney General Brief at 180-181, citing Exh. ES-REVREQ-6(b), Sch. 4.). Further, the Attorney General submits that each municipality's adoption of an alternative to the NBV property tax assessment method should be considered a separate exogenous event, particularly since various municipalities adopted an alternative method at different times (Attorney General Reply Brief at 31-32). In this regard, the Attorney General argues that the Department of Revenue ("DOR") has provided guidance to municipalities on adopting an alternative to the NBV tax assessment method but does not require cities and towns to use the alternative method (Attorney General Reply Brief at 32-33, citing Exh. ES-REVREQ-6(a), Sch. 4, at 3; Sch. 5, at 7). Finally, the Attorney General asserts that the Department previously rejected the notion that incremental property tax amounts across multiple municipalities should be combined and totaled for purposes of meeting the exogenous cost threshold in the PBR mechanism (Attorney General Brief at 180-181, citing Eversource Gas Company of Massachusetts, D.P.U. 21-112-A at 8-11 (June 3, 2022); D.P.U. 20-120, at 349-350; D.P.U. 19-120, at 332-338; D.P.U. 18-150, at 421-422; D.P.U. 17-05, at 558-559; Attorney General Reply Brief at 31-34).

b. TEC and PowerOptions

TEC and PowerOptions argue that the Department should continue to evaluate exogenous cost recovery of incremental property taxes on a non-cumulative, individual municipality basis and not combine totals from various municipalities for purposes of meeting the exogenous cost threshold (TEC/PowerOptions Brief at 13, citing D.P.U. 20-120, at 349-350). Further, TEC and PowerOptions assert that only NSTAR Electric can protect its ratepayers from "overly aggressive" property tax valuations, and it is imperative that the Company continue to vigorously contest unreasonably high assessments (TEC/PowerOptions Brief at 13).

c. Company

The Company argues that when costs are interrelated and caused by a single exogenous event, the costs should be calculated in the aggregate (Company Brief at 304-305, citing D.P.U. 18-101, at 20-21; Boston Gas Company, D.T.E. 05-66, at 11-13 (2005); Colonial Gas Company, D.T.E. 00-73, at 19-22 (2001)). In this regard, NSTAR Electric contends that the incremental property taxes at issue arise from DOR's decision to "formally transition" from the traditional NBV method of utility property valuation to the hybrid RCNLD/NBV approach, and that DOR's directives constituted a single exogenous event because it caused large numbers of municipalities (specifically, 187 of 194 municipalities) to change their tax valuation method and increase the Company's property taxes (Company Brief at 301-306).

According to the Company, to focus on each individual municipality's tax assessment as a separate and distinct exogenous event is legally flawed, as the exogenous event is not the municipality's decision to change the property tax valuation, but rather the municipalities need to comply with DOR's directive (Company Brief at 306-307; Company Reply Brief at 34-35). In this regard, the Company contends that legal "causation principles" point to DOR's purported directives as being the direct or proximate cause of 187 municipalities changing their valuation method and increasing property taxes beginning in fiscal years 2021 and 2022 (Company Brief at 306, citing Lynn Gas & Electric Company v. Meriden Fire Insurance Company, 158 Mass. 570, 575 (1893); Jussim v. Massachusetts Bay Insurance Company, 415 Mass. 24, 27 (1993); Company Reply Brief at 35-36).

Moreover, the Company argues that the Department has allowed exogenous cost recovery based on aggregate costs. For example, NSTAR Electric contends that the Department determined that the March 2018 Nor'Easter storm event, during which the Company was in a continuous state of storm preparation and restoration, should be treated as single major storm event for exogenous cost recovery (Company Reply Brief at 37-38, citing D.P.U. 18-101, at 11-12, 20-21). Thus, the Company claims that the Department should treat as a single exogenous event, the increase in incremental property taxes among various municipalities since the issuance of DOR's directives in 2019 (Company Brief at 307;

Company Reply Brief at 38). Based on the above considerations, the Company asserts that the Department should allow NSTAR Electric to recover $30,006,340 in incremental property taxes pursuant to the exogenous cost provision in the Company's current PBR mechanism (Company Brief at 307).

3. Analysis and Findings

In D.P.U. 17-05, at 395-398, the Department approved an exogenous cost factor as a component of the Company's PBR plan. Pursuant to NSTAR Electric's current PBR tariff, the Company must provide supporting documentation and rationale demonstrating that the proposed exogenous cost meets the following criteria: (1) the cost change must be beyond the Company's control; (2) the cost change arises from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) the cost change is unique to the electric distribution industry as opposed to the general economy; and (4) the cost change meets a threshold of significance for qualification. M.D.P.U. No. 59(E) at § 1.08.[158] The significance threshold for exogenous costs was set at $5 million for each individual event in

[158] The Department has defined exogenous costs as positive or negative cost changes actually beyond a company's control and not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include, but are not limited to, 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. In D.P.U. 17-05, at 396, we determined that NSTAR Electric's definition of exogenous costs in its proposed PBR tariff was consistent with the definition adopted by the Department in D.P.U. 94-50.

calendar year 2018, and thereafter was to be adjusted annually based on changes in GDP-PI. D.P.U. 17-05, at 397-398; M.D.P.U. No. 59(E) at § 1.08.

In D.P.U. 21-107-A at 18-19, the Department determined that a Local Finance Opinion issued by DOR in March 2019 (see n.154 above) constituted a regulatory policy change that lowered the burden of using a method other than NBV and induced a significant number of municipalities in NSTAR Gas' service area to change their valuation method. Further, we determined that DOR's regulatory policy change on NBV, while not mandating a specific valuation method, has driven widespread adoption by municipalities of an alternative property valuation method resulting in an incremental change in property tax expense in excess of NSTAR Gas' significance threshold. D.P.U. 21-107-A at 19. In addition, we found that the cost increases satisfy the criteria for an exogenous event because NSTAR Gas had incurred a cost change that: (1) arose from DOR's 2019 state-wide regulatory directive that it would no longer treat NBV as the default method for valuation of utility property taxes or give presumptive validity to valuations based on NBV; (2) was beyond NSTAR Gas' control; (3) was unique to the utility industry as opposed to the general economy; and (4) met NSTAR Gas's significance threshold. D.P.U. 21-107-A at 19. The Department distinguished our prior determinations that examined the significance of property tax expense changes driven by municipalities' independent decisions to change their method of property valuation and not driven by DOR's change in regulatory policy governing the utility industry. D.P.U. 21-107-A at 19-20.

We find that the same standard applied in D.P.U. 21-107-A to NSTAR Gas should apply to NSTAR Electric's proposal in the instant case. The record in the instant proceeding shows that at the time of NSTAR Electric's last base distribution rate case, D.P.U. 17-05, only six municipalities in the Company's service area had transitioned from NBV to the hybrid RCNLD/NBV method of assessing property taxes (Exh. DPU 16-1, Att. at 9-11 (Rev.)). The Company has demonstrated that 187 municipalities now have transitioned from NBV to the hybrid RCNLD/NBV method since the Department's Order in D.P.U. 17-05 (Exhs. ES-REVREQ-6(a), Sch. 2, at 9-11 (Supp.); DPU 16-1, at 2 & Att. at 9-11 (Rev.)). As such, we find that the Local Finance Opinion issued by DOR in March 2019 constituted a regulatory policy change that led a significant number of municipalities within NSTAR Electric's service area to change their valuation method. Further, we conclude that DOR's action was beyond NSTAR Electric's control and was unique to the utility industry as opposed to the general economy. In addition, NSTAR Electric's supporting documentation appears to show that the cost change resulting from DOR's actions meets the Company's significance threshold (Exhs. ES-REVREQ-6(a), Sch. 2, at 8 (Supp.); DPU 16-1, Att. at 8 (Rev.)).

The final determination of the amount of incremental property taxes eligible for recovery will be made in docket D.P.U. 22-120. Consistent with the findings in D.P.U. 21-107-A at 20, NSTAR Electric will need to demonstrate that its proposed exogenous cost adjustments include only the incremental property tax expense that arises from the exogenous event. Further, the Company must isolate the impact of municipalities' adoption of the hybrid RCNLD/NBV method following DOR's issuance of the Local Finance Opinion and follow the terms of the PBR tariff to implement the exogenous cost change. D.P.U. 21-107-A at 20. Once approved by the Department, the amount of the cost change shall be amortized over two years and recovered through a separate factor. We find this method of recovery is reasonable and appropriate given that the permanent increase in property tax expense due to the hybrid RCNLD/NBV method will be reflected in base distribution rates as a result of our Order today (see Exh. ES-REVREQ-27, Sch. 27 (Rev. 4); Department Schedule 7 below).

XIII. SERVICE QUALITY PERFORMANCE EXEMPTION

A. Introduction

The Department approved the current SQ Guidelines applicable to EDCs and local gas distribution companies in D.P.U. 12-120-D. The SQ Guidelines establish performance metrics and benchmarks against which the EDCs and local gas distribution companies must measure their performance annually. D.P.U. 12-120-D. The SQ Guidelines established the following metrics with an associated penalty for EDCs: SAIDI;[159] SAIFI;[160] CKAIDI;

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[159] SAIDI means the total duration of customer interruptions in minutes divided by the total number of customers served by the EDC, expressed in minutes per year. SAIDI characterizes the average length of time that customers are without electric service during the reporting period. D.P.U. 12-120-D, Att. A at 6.

[160] SAIFI means the total number of customer interruptions divided by the total number of customers served by the EDC, expressed in number of interruptions per customer per year. SAIFI characterizes the average number of sustained electric service interruptions for each customer during the reporting period. D.P.U. 12-120-D, Att. A at 6.

CKAIFI; Service Appointments Kept As Scheduled; Customer Complaints; and Customer Credit Cases. D.P.U. 12-120-D, Att. A. The SQ Guidelines require EDCs to annually report their performance for each of these metrics and pay monetary penalties if their performance does meet the applicable benchmarks. D.P.U. 12-120-D at 7-16. The EDCs must include all relevant data when calculating their annual performance for each metric, unless some data has been excluded either because it meets the definition of an "Excludable Major Event" or a company requested, and the Department approved, a limited exemption. D.P.U. 12-120-D, Att. A at 4, 25. The SQ Guidelines define the term Excludable Major Event as follows:

> "Excludable Major Event" means a major Interruption event that meets one of the three following criteria: (1) the event is caused by earthquake, fire or storm of sufficient intensity to give rise to a state of emergency proclaimed by the Governor (as provided under the Massachusetts Civil Defense Act); (2) any other event that causes an unplanned Interruption of service to fifteen percent or more of the Electric Company's total customers in the Electric Company's entire service territory; or (3) the event was a result of the failure of another Company's transmission or power supply system. Excludable Major Events apply to all SQ reliability metrics. Notwithstanding the foregoing criteria, an Interruption event caused by extreme temperature condition is not an Excludable Major Event.

D.P.U. 12-120-D, Att. A at 4. Excludable Major Events are the only events automatically excluded from the calculation of all SQ metrics. D.P.U. 12-120-D, Att. A at 12. The SQ Guidelines, however, allow EDCs to request a limited exemption from a particular portion of the SQ Guidelines, including circumstances where an event does not meet the definition of Excludable Major Event. D.P.U. 12-120-D, Att. A, at 25. For example, the Department may grant an exemption from a particular metric or metrics if extraordinary circumstances arise during an outage event that render prompt service restoration beyond an EDC's reasonable control. D.P.U. 12-120-D, Att. A at 25; 2020 Electric Service Quality Reports, D.P.U. 21-SQ-10 through 21-SQ-13, at 6 (February 4, 2022), citing Petition by Local Gas Distribution Companies for Limited Waiver of Service Quality Guidelines, D.P.U. 15-56, at 5 (2016).

B. Company Proposal

NSTAR Electric requests that, for SQ reporting purposes, the Department allow storms with SAIDI values more than four standard deviations from the Company's mean to be excluded from the computation of SAIDI/SAIFI performance for that year (Exh. ES-CAH/DPH-1, at 106-107). The Company's proposal would not change the current definition of Excludable Major Event, but instead would create a second circumstance under which single days automatically would be excluded from metric calculations (Exh. NG 1-1). Thus, under the Company's proposal, events with customer outages exceeding the 15-percent threshold still would be excluded from SAIDI/SAIFI reporting pursuant to the Excludable Major Event definition, and events with less than 15 percent customer outages, but with a SAIDI value more than four standard deviations from the mean, also would be excluded automatically (Exh. NG 1-1).

C. Positions of the Parties

1. National Grid (electric)

National Grid (electric) supports NSTAR Electric's proposal and argues that the Department's exclusion criteria should be refined to recognize that EDCs have made substantial investments in their systems over the past 20 years, yet significant storms continue to occur that, because of the investments, do not trigger the Excludable Major Event threshold (National Grid (electric) Brief at 6-10, citing Exhs. ES-CAH/DPH-1, at 102-104; ES-CAH/DPH-2; NG-1, at 9-10; NG 1-1). According to National Grid (electric), the current three-year rolling average option to mitigate or eliminate penalties neither rectifies the influence of weather conditions beyond the control of the companies nor accounts for the effect of system improvements and an increasing customer base (National Grid (electric) Brief at 4-5, citing Exh. NG-1, at 7-9). National Grid (electric) asserts that NSTAR Electric's proposal more appropriately recognizes the impact of system improvements and an increased customer base over the past 20 years (National Grid (electric) Brief at 5-6, citing Exh. ES-CAH/DPH-1, at 101).

Further, National Grid (electric) contends that the Company's proposal is not a request for the Department to replace the existing definition of Excludable Major Event, but rather to add a second-tier test that "would work in conjunction with the existing definition of Excludable Major Event" (National Grid (electric) Brief at 7-8, citing Exh. NG 1-1). National Grid (electric) asserts that NSTAR Electric's proposed automatic exclusion would provide a bridge until a future generic proceeding, wherein the Department can reevaluate the current 15-percent exclusion threshold as part of a broader inquiry into updating the SQ Guidelines (National Grid (electric) Brief at 8, 15, citing Exhs. ES-CAH/DPH-1, at 103-105; NG-1, at 14-16; NG 1-1).[161]

[161] National Grid (electric) argues that in future generic SQ proceedings, the Department should reduce the 15-percent threshold criteria because only extraordinarily large weather impacts are excluded from the day-to-day computation of "reliability," which

2. Company

NSTAR Electric argues that the definition of an Excludable Major Event has remained unchanged for 20 years, despite the technological and operational improvement to the Company's system over that same time period (Company Brief at 93, citing Exh. ES-CAH/DPH-1, at 101). In this regard, the Company contends that it has improved the reliability of its distribution system such that the number of customers interrupted per storm has decreased by 30 percent over the past ten years (Company Brief at 92, citing Exh. ES-CAH/DPH-1, at 99-100). NSTAR Electric asserts, however, that because of the decrease in customer interruptions, fewer storms meet the 15-percent threshold for an Excludable Major Event, yet still cause significant damage and, therefore, are included in the annual SAIDI and SAIFI calculations (Company Brief at 92, citing Exh. ES-CAH-DPH-1, at 100). According to NSTAR Electric, including such data in the SAIDI and SAIFI calculations gives the false impression that reliability is worsening and the Company's SAIDI and SAIFI performance is declining (Company Brief at 92-93, citing Exh. ES-CAH/DPH 1, at 99-100). NSTAR Electric asserts that its proposal accounts for the Company's reliability improvements and increased customer counts (Company Brief at 93-94, citing Exh. ES-CAH/DPH-1, at 101).

National Grid (electric) claims is not a valid methodological approach for SAIDI/SAIFI computations (National Grid (electric) Brief at 8, citing Exh. NG 1-1 n.5).

NSTAR Electric argues that its proposal is supported by a comprehensive analysis of the SAIDI and SAIFI performance measures, which demonstrate that severe weather events have not been properly excluded from the computation of SAIDI and SAIFI for measuring day-to-day reliability (Company Brief at 94, citing Exhs. ES-CAH/DPH-1, at 103-104; ES-CAH/DPH-2). In particular, the Company asserts that its analysis shows that there are weather events that are causing days with SAIDI performance that are four standard deviations from the average daily performance but are not reaching the 15-percent threshold of customers experiencing a service interruption (Company Brief at 93-94, citing Exhs. ES-CAH/DPH-1, at 103-104; ES-CAH/DPH-2). Finally, the Company contends that its proposal to exclude days with a SAIDI value exceeding four standard deviations from the mean is intended to provide a bridge until the Department opens a future generic proceeding to address the SQ Guidelines (Company Brief at 94, citing Exhs. NG 1-1; NG 1-4).

D. Analysis and Findings

NSTAR Electric proposes to exclude data from event days that may indicate severe distribution system damage, yet do not meet the current definition of an Excludable Major Event (Exhs. ES-CAH/DPH-1, at 106-107; NG 1-1). NSTAR Electric argues that, unlike the current definition of Excludable Major Event, the Company's proposal accounts for reliability improvements and increased customer counts on the distribution system (Company Brief at 93-94, citing Exh. ES-CAH/DPH-1, at 101).

The Department recognizes that the definition of Excludable Major Events has remained unchanged for over 20 years and may no longer accurately account for emergency events resulting in severe damage, or for the changes to distribution systems and increased customer counts. Service Quality Guidelines for Electric Distribution Companies and Local Gas Distribution Companies, D.T.E. 99-84, Att. at 2 (2001). The Department intends to open a proceeding within the next year to evaluate the current SQ Guidelines, at which time the EDCs and relevant stakeholders will have an opportunity to comment on proposed refinements to the Guidelines. In the interim, however, we find that it is reasonable and appropriate to approve the Company's proposal. The Company's proposal and attendant analysis demonstrates that events with SAIDI values greater than four standard deviations from the mean tend to cause significant damage, despite not reaching the current customer outage criteria for an Excludable Major Event (Exhs. ES-CAH/DPH-1, at 103-106; ES-CAH/DPH-2). As such, including these event days in the SAIDI/SAIFI calculations may skew NSTAR Electric's overall performance results and may not accurately reflect the Company's efforts to improve reliability of the distribution system. While we recognize that under the current SQ Guidelines NSTAR Electric may seek specific exemptions for severe weather events that do not meet the definition of an Excludable Major Event but nonetheless have a severe impact on a utility's distribution system, we find that the Company's proposal presents a straightforward, verifiable, and efficient alternative to such an exemption (Exhs. ES-CAH/DPH-1, at 104-107; ES-CAH-DPH-2). In this regard, we do not consider the Company's proposal as a permanent change to the definition of what constitutes an Excludable Major Event under the current SQ Guidelines. Rather, the proposal is an interim measure that will be reevaluated over time until the Department updates the SQ Guidelines.

Based on these considerations, the Department approves the Company's proposal to exclude from the annual SAIDI and SAIFI metric calculations, event days where the SAIDI values exceed the mean plus four standard deviations. As the SQ Guidelines apply to each EDC, so too will this event day exemption, effective immediately. More specifically, the EDCs may begin applying this exemption in their 2022 annual SQ report filings, for the full 2022 calendar year of data. The EDCs shall follow the method for calculating the event day exemption as presented by the Company in Exhibit ES-CAH/DPH-2. Consistent with the SQ Guidelines as they relate to Excludable Major Events, the EDCs shall demonstrate in their annual SQ report filings why any data excluded pursuant to this event day exemption qualifies for exclusion and calculate annual SAIDI and SAIFI performance both with and without the excluded data. The Department will evaluate each EDC's annual SAIDI and SAIFI performance using the values with the relevant event day exemptions, provided the companies file all appropriate calculations, assumptions, and data in their respective annual SQ report filings.

As noted above, the Department plans to revisit the SQ Guidelines in the next year, at which point we will further evaluate the event day exemption and its effectiveness at providing a more accurate impression of reliability improvements and increased customer counts on the EDCs' distribution systems. The Department may modify or eliminate the event day exemption based on that evaluation, or during our review of the annual SQ reports should circumstances warrant.

XIV. SMART PROGRAM AND SOLAR EXPANSION PROGRAM INVESTMENTS

A. SMART Program Investments

1. Introduction

On September 12, 2017, pursuant to G.L. c. 164, § 94, Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"), National Grid (electric), and NSTAR Electric and the former WMECo (collectively "Distribution Companies") filed with the Department a joint petition for approval of a model Solar Massachusetts Renewable Target ("SMART") Provision tariff ("SMART Provision") to implement An Act Relative to Solar Energy and DOER regulations ("SMART Program"). St. 2016, c. 75, § 11(b); G.L. c. 25A, § 6; 225 CMR 20.00. The Department docketed the petition as D.P.U. 17-140.[162]

On September 26, 2018, the Department issued a final Order approving the SMART Provision. Joint Petition for Approval of Model Solar Massachusetts Renewable Target Tariff, D.P.U. 17-140-A, Order Approving Model SMART Provision (September 26, 2018) ("SMART Order"). In the SMART Order, the Department determined that the Distribution Companies may recover the following: (1) the incremental O&M and capital costs necessary to meet the SMART Program's objectives; (2) an estimate of the net cost of the incentive

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[162] The Attorney General, DOER, Acadia Center, BCC Solar Advantage, Inc., Genbright, LLC, and Solar Energy Industries Association were granted intervenor status. Joint Petition for Approval of Model Solar Massachusetts Renewable Target Tariff, D.P.U. 17-140-A, Order Approving Model SMART Provision at 2-3 (September 26, 2018). Associated Industries of Massachusetts was granted limited participant status. D.P.U. 17-140-A, Order Approving Model SMART Provision at 3 (September 26, 2018).

payments, alternative on-bill credits ("AOBCs"), and revenues generated from the SMART Program; and (3) a reconciliation adjustment with applied interest. SMART Order at 143-160. These costs are to be recovered through a SMART factor consistent with certain directives and the formula established in each Distribution Company's respective tariff. SMART Order at 181-190. The Distribution Companies are required to make an annual cost recovery and reconciliation filing for the SMART factor on or before November 1st of each year, for effect January 1st of the next year. SMART Order at 197. NSTAR Electric's current SMART tariff is M.D.P.U. No. 74D.

In accordance with the directives in the SMART Order, the Company filed annual SMART factor filings in dockets D.P.U. 18-132, D.P.U. 19-125, D.P.U. 20-131, and D.P.U. 21-134. The Department issued Phase I Orders in each docket and approved the Company's proposed SMART factors, subject to further investigation. NSTAR Electric Company, D.P.U. 21-134, at 4-5 (2021); NSTAR Electric Company, D.P.U. 20-131, at 5-6 (2020); NSTAR Electric Company, D.P.U. 19-125, at 5-6 (2019); NSTAR Electric Company, D.P.U. 18-132, at 4-5 (2018). On May 21, 2020, the Department issued a final Order approving the 2019 SMART Program costs, subject to certain directives. D.P.U. 18-132-A at 3 8. At the time of the initial filing in the instant proceeding, the Department had not issued final Orders in D.P.U. 19-125, D.P.U. 20-131, and D.P.U. 21-134. The Department subsequently issued a final Order in D.P.U. 21-134. D.P.U. 21-134-A (November 29, 2022).

2. Company Proposal

The Company proposes to transfer the recovery of expenses for ESC net plant balances associated with $11.4 million in SMART Program capital additions, placed in service through December 31, 2021, to base distribution rates (Exhs. ES-REVREQ-1, at 41-42; ES-ADDITIONS-1, at 51; ES-ADDITIONS-7, Att. (a) (Supp).; DPU 14-2; DPU 39-20, at 1-2; DPU 39-21). The Company proposes to include the revenue requirement associated with those investments charged to the Company as Enterprise IT O&M expense, or $1,908,643, in the computation of the revenue requirement underlying base rates that become effective January 1, 2023 (Exhs. ES-REVREQ-1, at 22, 41-42; ES-REVREQ-4, Sch. 9 (Rev. 1)).[163] Thus, beginning January 1, 2023, the Company would recover the costs associated with the remaining un-depreciated SMART investments through distribution rates (Exh. DPU 39-20, at 2). The Company states that these costs represent IT system enhancements, including data interfaces and billing system modifications used to support an additional line item for the SMART factor on customer bills (Exhs. ES-ADDITIONS-1,

163 The Company included corresponding revenues of $1,893,718 associated with SMART Program expenses for purposes of reflecting the appropriate revenue deficiency (Exhs. ES-REVREQ-1, at 25; ES-REVREQ-2, Sch. 1, at 9; Sch. 6 (Rev. 4)). SMART Program revenues associated with the sale of product revenues (i.e., revenues from the sale of energy, forward capacity market, and sale of solar renewable energy credits) will continue to be included in the SMART mechanism, as well as, the: (1) incentive payments for RPS Class I renewable generation attributes and/or environmental attributes produced by a solar tariff generation unit; (2) AOBCs for energy generated by an AOBC generation unit; (3) the basis upon which incentive payments and AOBCs are determined; and (4) the recovery of any such incentive payments, AOBCs, and certain incremental administrative costs associated with the implementation and operation of the SMART Program (Exh. ES-REVREQ-1, at 25).

at 51; DPU 14-1). According to the Company, it has produced in the instant proceeding all of the documentation necessary for the Department to conduct a prudency review of these costs (Exhs. ES-ADDITIONS-1, at 51; ES-REVREQ-1, at 44; ES-ADDITIONS-7 & Supp.).

The Company notes, however, that it will not recover the revenue requirement earned under its SMART tariff prior to new base distribution rates taking effect due to the timing of the SMART filings, which go into effect on January 1st of each year and include a twelve-month lag between when investments are placed in service to when recovery begins (Exh. ES-REVREQ-1, at 42). Thus, the Company proposes for the earned revenue requirement to be recovered through the SMART tariff and after the effective date of new base distribution rates set in this proceeding (Exh. ES-REVREQ-1, at 42). Specifically, NSTAR Electric proposes that, by November 1, 2022, it will file its annual SMART Program filing for actual investments placed in service on or before August 30, 2022, and that the associated SMART factor will be effective January 1, 2023 through December 31, 2023 to allow for the recovery of the 2022 revenue requirement on the SMART Program costs (Exh. ES-REVREQ-1, at 42-43). Then, by November 1, 2023, the Company will file its annual SMART Program filing for actual investments placed in service on or before August 30, 2023, and the associated SMART factor will be effective January 1, 2024 through December 31, 2024, to allow for the recovery of the 2023 revenue requirement on the SMART Program costs (Exh. ES-REVREQ-1, at 43). At this point, the SMART factors no longer will recover investments that have been reflected in base rates as of January 1, 2023 (Exh. ES-REVREQ-1, at 43).

3. Positions of the Parties

The Attorney General argues that the Department should deny the Company's request to transfer to base distribution rates the costs associated with the SMART Program, as these costs already are recovered in reconciling mechanisms (Attorney General Brief at 113-116). Further, the Attorney General argues that the Department need not transfer costs into base distribution rates at this time because of the open SMART dockets (Attorney General Brief at 116). Rather, the Attorney General asserts that the Department should continue to adjudicate the SMART Program costs in the open SMART Program dockets (Attorney General Brief at 116).

The Company restates its SMART Program proposals on brief (Company Brief at 128, 135-136, 141, 389, 391). The Company, on brief, addresses the proposed roll-in of capital additions, but does not specifically address the Attorney General's arguments about the SMART Program investments (Company Brief at 52-53).

4. Analysis and Findings

In the SMART Order, the Department determined the categories of recoverable costs associated with the SMART Program, and the process by which the Company could recover such costs, after they have been reviewed and approved by the Department. SMART Order at 143-160, 181-190, 197. In particular, we determined that it was reasonable to allow recovery through the SMART factor of costs to upgrade IT and billing systems that are specifically related to SMART Program implementation. SMART Order at 150. Since that Order, the Company has recovered SMART-related costs through its SMART factor, subject to further investigation by the Department. D.P.U. 21-134, at 4-5; D.P.U. 20-131, at 5-6; D.P.U. 19-125, at 5-6; D.P.U. 18-132, at 4-5. As noted above, final Orders have issued in dockets D.P.U. 18-132 and D.P.U. 21-134.

In the instant proceeding, the Company requests that the Department conduct a prudency review of several years of SMART-related IT system enhancement capital additions and then transfer the unrecovered balance of these investments to base rates (Exhs. ES-ADDITIONS-1, at 51; ES-REVREQ-1, at 22, 41-42; DPU 39-20, at 1-2; DPU 39-21).[164] We decline to do so. First, we find that it is more appropriate and efficient to review all of the costs subject to recovery in the individual outstanding SMART Program dockets, rather than to undertake a piecemeal review of the IT-related capital costs. Next, as noted above, the Department already determined that recovery of certain IT-related costs, such as those proposed by the Company, should be recovered through the SMART factor. SMART Order at 150. We see no compelling reason to allow an alternative cost recovery method at this time. As the Company can recover the final allowable costs associated with the IT system enhancements through the SMART factor, denying the proposal in this case does not result in cost disallowance. Finally, in the SMART Order we directed the Company to designate the SMART factor as a separate line item for the purposes of bill clarity and bill transparency. SMART Order at 195. We find that continuing to allow recovery through the

164 The Department recognizes and appreciates the Company's resource intensive efforts in providing supporting documentation associated with its SMART Program capital additions (Exhs. ES-ADDITIONS-7 & Supp.; DPU 14-5 (Supp.)).

SMART factor, as opposed to recovering some costs through base distribution rates, maintains the important considerations of bill clarity and transparency.

Based on the above considerations, the Department rejects the Company's proposal to transfer the unrecovered balance of SMART-related IT investments in base distribution rates. As noted above, the Company sought to include $1,908,643 in SMART Program costs in base rates effective January 1, 2023 (Exhs. ES-REVREQ-1, at 22, 41-42; ES-REVREQ-4, Sch. 9 (Rev. 1)). The Company also included in the proposed revenue requirement SMART Program revenues in the amount of $1,893,718 (Exhs. ES-REVREQ-1, at 25; ES-REVREQ-2, Sch. 1, at 9; Sch. 6 (Rev. 4)). The Department removes the SMART Program costs and revenues from the proposed cost of service. The effect of our decision is shown on Schedules 2 and 9 below.

B. Solar Expansion Program Investments

1. Introduction

On June 30, 2016, NSTAR Electric and WMECo filed with the Department a proposal to construct, own, and operate up to 62 MW of solar generation facilities ("Solar Expansion Program") pursuant to G.L. c. 164, § 1A(f). NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 16-105 (2016).[165] The Department

165 In its initial filing, the Company proposed to move into base distribution rates costs related to its Solar Program approved in D.P.U. 09-05 and Western Massachusetts Electric Company, D.P.U. 13-50 (2013). During the proceeding, the Company acknowledged that it had not conferred with the Attorney General as outlined in D.P.U. 09-05 (Exh. DPU 37-3). As such, the Company withdrew its proposal and made certain adjustments to its proposed cost of service to reflect the removal of these

approved the proposal, which included pre-approval of capital installation and replacement costs, annual operating expenses, and annual lease and property tax expenses. D.P.U. 16-105, at 35-36. In particular, the Department approved a spending cap of $205.7 million on capital installation and replacement costs. D.P.U. 16-105, at 30, 33, 36.

Pursuant to the Company's solar expansion cost recovery mechanism ("SECRM") tariff, as Solar Expansion Program generation facilities are constructed and placed into service, the Company files every six months for adjustments to its solar expansion cost recovery factors ("SECRFs"), beginning on January 1st of each calendar year. The SECRM recovers the investment and ongoing maintenance costs of the solar generation projects, offset by any credits for the sale of energy; either the sales of renewable energy credits ("RECs") into the ISO-NE market or the market value of RECs used to comply with the Renewable Portfolio Standard ("RPS"); and capacity sales, if any (Exh. ES-REVREQ-1, at 34). The SECRFs are reconciled on an annual basis.

2. Company Proposal

The Company reports that it has successfully commissioned the full approved scope of 62 MW approved by the Department in D.P.U. 16-105 (Exh. ES-ADDITIONS-1, at 48). Further, NSTAR Electric states that the Department, through several Solar Expansion Program compliance filings, has reviewed and analyzed the Company's Solar Expansion Program investments and found the costs to be prudent and the facilities used and useful in

investments from the revenue requirement (Exhs. ES-REVREQ-2, Sch. 1, at 9; Schs. 6, 27, 29-32 (Rev. 4); ES-REVREQ-3, WP 27, at 3 (Rev. 4); DPU 37-3).

providing service to customers (Exh. ES-ADDITIONS-1, at 48, citing NSTAR Electric Company, D.P.U. 19-127-A (2021); NSTAR Electric Company, D.P.U. 19-59-A (2020); NSTAR Electric Company, D.P.U. 18-124-A (2020)). The Company proposes to transfer the Solar Expansion Program capital investments through 2021, totaling $161,594,319, into rate base in this proceeding (Exhs. ES-ADDITIONS-1, at 48; ES-ADDITIONS-12, Att. (b); DPU 37-2).

3. Positions of the Parties

The Attorney General argues that the Department should deny the Company's request to transfer to base distribution rates the costs associated with the Solar Expansion Program, as the costs already are recovered through a reconciling mechanism (Attorney General Brief at 113). We address this argument below. The Attorney General makes several additional arguments, in the context of the proposed PBR plan and annual PBR adjustment, regarding the transfer of the Solar Expansion Program investments to base distribution rates (Attorney General Brief at 113-117, citing Exh. AG-TN-1, at 4-10). The Company raises counter arguments on brief (Company Brief at 52-53). We address these issues in Section IV.D.5.j above.

4. Analysis and Findings

The Department previously determined that the Company acted prudently in undertaking the construction of the Solar Expansion Program facilities and that the facilities were used and useful in providing service to customers prior to the end of the test year.

See D.P.U. 19-127-A at 3, 8; D.P.U. 19-59-A at 4, 12; D.P.U. 18-124-A at 2, 10. Accordingly, we need not review the investments for a prudency or in-service determination.

As noted above, the Company proposes to transfer the Solar Expansion Program capital investments through 2021, totaling $161,594,319, into base distribution rates in this proceeding (Exhs. ES-ADDITIONS-1, at 48; ES-ADDITIONS-12, Att. (b); DPU 37-2). The 2021 capital expenditures were necessary to complete the final close-out activities of the solar facilities that were initiated under the Solar Expansion Program (Exhs. ES-ADDITIONS-1, at 48; ES-ADDITIONS-12, Att. (b); DPU 37-2). These costs include contractor and engineering services, licensing and permitting fees, and other outside services (Exhs. ES-ADDITIONS-12, Att. (b); DPU 37-2). The total 2021 costs also include a refund from National Grid for interconnection costs at one of the solar facilities (Exh. DPU 37-2). As a result, the overall 2021 costs reduce the Company's test-year net plant in service by $793,724 (Exh. DPU 37-2). The Department has reviewed the 2021 costs and supporting documentation, and we find the costs to be reasonable and represent a known and measurable change to the test-year amount. Further, we note that the Company's total capital investment for the Solar Expansion Program is below the spending cap of $205.7 million on capital installation and replacement costs set in D.P.U. 16-105, at 30, 33, 36.

Given that the Solar Expansion Program costs were prudently incurred, the facilities are used and useful in providing service to customers, and the total investment is below the authorized spending cap, we find it reasonable, appropriate, and consistent with precedent to transfer the investments to NSTAR Electric's rate base and allow the Company to recover the unrecovered balance through base distribution rates. See, e.g., D.P.U. 18-150, at 203. Thus, we are not persuaded by the Attorney General's argument to the contrary. Accordingly, the Department allows the Company to transfer the Solar Expansion Program capital investments through 2021, totaling $161,594,319, into base distribution rates in this proceeding.

XV. ADVANCED METERING INFRASTRUCTURE PROPOSALS

A. Introduction

In NSTAR Electric Company, D.P.U. 21-80, NSTAR Electric requested Department approval of its AMI Implementation Plan and submitted for review a model tariff to establish an annual reconciling mechanism to recover costs associated with its plan (Exhs. ES-REVREQ-1, at 200; ES-CAH/DPH-1, at 14, 109-110; ES-AMI-1, at 8, 16-19; DPU 7-1). In the instant proceeding, NSTAR Electric submitted a company-specific rate tariff, proposed M.D.P.U. No. 80, for approval based on the model tariff presented in D.P.U. 21-80 (Exhs. ES-CAH/DPH-1, at 30; ES-AMI-1, at 11, 17; ES-AMI-2; ES-RDC-6, Sch. 1, at 556-561; DPU 7-1). The Company requests that the Department adopt the model tariff for company-specific application and authorize recovery of AMI investment costs after January 1, 2023 (Exh. ES-AMI-1, at 16-17).

As proposed, the company-specific tariff establishes an annual reconciling mechanism and factor allowing NSTAR Electric to recover an annual AMI revenue requirement associated with the Company's AMI-related plant in service for each AMI investment year prior to the recovery year, as well as recoverable O&M expense (Exhs. ES-AMI-1, at 19;

ES-AMI-2; ES-RDC-6, Sch. 1, at 556-561). Specifically, the AMI revenue requirement would be calculated to recover: (1) the monthly revenue requirement for eligible AMI investments recorded as in service in the AMI investment year immediately prior to the recovery year; (2) the average annual revenue requirement for the calendar year ending December 31 of the AMI investment year two years prior to the recovery year, for cumulative eligible investments placed into service in the AMI investment years two years prior to the recovery year; (3) the annual revenue requirement for the recovery year on eligible investments recorded as in service in the AMI investment year immediately prior to the recovery year; and (4) actual monthly AMI-related O&M expenses incurred in the AMI investment year prior to the recovery year (Exhs. ES-REVREQ-1, at 200-201; ES-AMI-1, at 19-20; ES-AMI-2, at 1-5; ES-RDC-6, Sch. 1, at 556-560). The proposed AMIF would apply to all retail delivery service kWh, pursuant to annual Department prudency reviews and approval (Exhs. ES-AMI-1, at 16; ES-AMI-2, at 1, 5-6; ES-RDC-6, Sch. 1, at 560-561). As contemplated in the proposed tariff, NSTAR Electric would submit to the Department an annual AMI cost recovery filing by May 15 that would include the following: (1) project documentation of all eligible AMI investment recorded as in service by the Company during the prior AMI investment year; (2) documentation supporting non-recurring O&M expense as part of recoverable O&M expense; (3) the AMI reconciliation calculation; and (4) bill impacts (Exhs. ES-REVREQ-1, at 201; ES-AMI-1, at 20; ES-AMI-2, at 5-6; ES-RDC-6, Sch. 1, at 560-561). Pursuant to Department review and approval, the AMIF would be in effect from July 1 to June 30 of each year (Exhs. ES-AMI-2, at 1, 4-5; ES-RDC-6, Sch. 1, at 559-560).

As part of the Company's AMI Implementation Plan, NSTAR Electric has proposed an increase in the depreciation accrual rate for Account 370.10 (Meters – AMR). As discussed in more detail in Section VII.B.1 above, the Company's proposed depreciation rate of 8.62 percent is intended to align with the planned deployment of AMI and retirement of AMR meters by 2028 (Exhs. ES-REVREQ-1, at 202-203; ES-AMI-1, at 21). Because AMR meters will continue to be purchased and installed prior to AMI implementation, NSTAR Electric proposes to treat any remaining undepreciated plant associated with AMR meters at the time of full AMI implementation as a regulatory asset (Exhs. ES-REVREQ-1, at 203-204; ES-AMI-1, at 21-22). Under the Company's proposal, the amortization for the regulatory asset would be based on the period of recovery of investment through depreciation of AMR meters approved in the instant proceeding (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22). NSTAR Electric proposed that after the regulatory asset is fully amortized, the Company would apply the amount of depreciation in base distribution rates against the recovery of the AMI cost recovery mechanism (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22).

NSTAR Electric also proposed to establish a cost-of-service benchmark for metering infrastructure to determine incremental O&M expense related to AMI (Exh. REVREQ-1, at 202-203, 205-209). In particular, the Company proposed to measure incremental costs based on the test-year level of costs for meter expenses, maintenance of meters, meter reading expenses, and miscellaneous customer accounts expenses as measured by the FERC

Account (Exh. ES-REVREQ-1, at 205-206). Using FERC Accounts 586, 597, 902, and 905, the Company calculated $9.7 million in test-year metering costs (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24; ES-AMI-3, at 1). This amount represents the baseline amount the Company proposed to compare against to determine incremental cost recovery for AMI meter-related O&M (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24). NSTAR Electric proposed to track and provide documentation for the O&M costs incurred related to AMI implementation, and to recover as incremental costs the lesser of these costs or the net change to FERC Accounts 586, 597, 902, and 905 from the test-year amount of $9.7 million, adjusted each year for the annual change in GDP-PI (Exhs. ES-REVREQ-1, at 206-207; ES-AMI-1, at 24-25).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that the Department should deny any new capital tracker cost recovery mechanism proposed by NSTAR Electric (Attorney General Brief at 39, 55).[166] The Attorney General contends that the annual rate increases contemplated by the proposed PBR plan will provide recovery for all costs of providing electric distribution service, and that the recovery mechanisms will overcompensate the Company for costs related to AMI and customer information systems ("CIS") investments (Attorney General Brief at 39). As an

166 TEC and PowerOptions also argue the Department should decline to adopt new capital trackers, including one for AMI costs, beyond the scope of the grid modernization proceedings (TEC/PowerOptions Brief at 14).

alternative, and as discussed in further detail in Section IV.C.1 above, the Attorney General recommends establishing an all-in capital tracker in lieu of a PBR plan, and she argues it would obviate the need for the Company's AMI cost recovery proposals here and in D.P.U. 21-80 (Attorney General Brief at 43). Under this scenario, the Attorney General indicates that the all-in capital tracker would allow for recovery of all NSTAR-specific investments (Attorney General Brief at 43).

The Attorney General maintains that if the Department rejects the proposed all-in tracker recommendation, it should still reject or modify the Company's AMI-related proposal (Attorney General Brief at 44). On brief, the Attorney General reiterates the arguments she presented in D.P.U. 21-80 (Attorney General Brief at 44-51). First, the Attorney General contends that AMI capability is not a special investment that requires exceptional recovery outside of base distribution rates, but instead should be treated as business as usual and accounted for in the proposed PBR plan and rate formula increases to base distribution rates (Attorney General Brief at 44-49, citing Exhs. AG-TN-1, at 12-13; AG-TN-2, at 2-14).

Additionally, the Attorney General claims that the proposed company-specific AMI tariff has the same issues she identified in the model AMI tariff submitted in D.P.U. 21-80 (Attorney General Brief at 49). Specifically, the Attorney General contends the proposed tariff has the following flaws: (1) the AMI revenue requirement in Section 2.7 does not recognize, nor does it "net out" recovery of the meter system cost recovery that already exists in base distribution rates; (2) the AMI revenue requirement in Section 2.7, parts (1) and (3) provide double recovery of the costs of plant placed in service during the investment year; (3) the eligible investment in Section 2.10 should recognize and adjust for the meter investment, whether "in service" or in the warehouse inventory, of newer AMR or bridge meters than can be repurposed for those customers who opt-out of AMI; (4) the tariff makes no provision for the reduction in O&M expense related to embedded meter investment or otherwise that any new capital investment creates; (5) the recoverable O&M expense charged from the service company in Section 2.16 should reflect only the appropriate and reasonable allocated share of any such service company costs, and not any amount that is "charged;" (6) the property tax rate definition in Section 2.14 should reflect the total utility property tax paid for the year as a percentage of the total utility property valuation for that same tax year and not the net plant; (7) there is no indication that the tariffed charge provides for a fully reconciling charge; (8) there is no definition of the term "incremental" that is it is used in Sections 1.0 and 2.16; (9) there is no provision for reconciliation or incorporation of the costs recovered through the charge with those recovered through base distribution rates; and (10) there is no provision for termination of the tariff (Attorney General Brief at 49-50, citing Exhs. ES-AMI-2; AG-TN-2, at 14-16). To the extent that the Department approves the Company's proposed tariff, the Attorney General argues that the necessary changes should be made to correct these flaws (Attorney General Brief at 50). Consistent with the recommendations made in D.P.U. 21-80, the Attorney General also requests the AMI cost recovery tariff be amended such that NSTAR Electric can only earn a return on its grid modernization investments after it shows that it has actually achieved and delivered to ratepayers the benefits the Company projected in its benefit cost analysis (Attorney General Brief at 50-51).

Regarding the Company's proposal to track and document incremental O&M costs and savings, the Attorney General argues it is inadequate for two reasons: (1) the use of actual savings does not hold the Company accountable for delivering benefits of the same magnitude and within the timeframes that its business case projects; and (2) the proposal leaves other rate-case-dependent benefits quantified in the AMI business case, including reductions in bad-debt expense and truck rolls from "no trouble found" incidents unaccounted for (Attorney General Brief at 53-54). As she recommends in D.P.U. 21-80, the Attorney General requests that the Department reduce the Company's AMI cost recovery revenue requirement by the amount of O&M savings and revenue assurance benefits projected in the benefit cost analysis until the actual cost reductions are fully captured and reflected in a subsequent base distribution rate case (Attorney General Brief at 54).

Finally, the Attorney General argues that the proposed company-specific tariff should be amended to reflect net cost reductions back to ratepayers if the Company receives government funding (Attorney General Brief at 54). Because the Company asks for timely approval of its AMI plan and cost recovery proposal to increase its likelihood of obtaining Infrastructure Investment and Jobs Act ("2021 IIJA")[167] funding, the Attorney General claims that there should be a mechanism to flow back to ratepayers any 2021 IIJA funding, or any

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[167] Infrastructure Investment and Jobs Act of 2021, Pub. L. 117-58.

other federal or state funding, for the Company's AMI system investments (Attorney General Brief at 54-55). Therefore, she argues the proposed tariff must include a provision to ensure ratepayers realize the benefits of government funding immediately (Attorney General Brief at 55).

2. Company

NSTAR Electric asserts its narrow proposal in the instant proceeding is to obtain Department approval of the company-specific AMI tariff, which follows from the model AMI tariff submitted in D.P.U. 21-80 (Company Brief at 371, citing Exh. DPU 7-1). The Company maintains that approval of the proposed tariff is the next step in establishing the platform to support the Company's AMI Implementation Plan (Company Brief at 371-372, citing Exhs. ES-AMI-1, at 8; DPU 7-1). NSTAR Electric asserts that under the proposal all AMI capital additions will be subject to a prudence review as the costs are proposed for recovery through the reconciling mechanism (Company Brief at 372, citing Exh. ES-AMI-1, at 16). The Company contends that it has proposed an end-of-life meter replacement plan that is consistent with the directives in Modernization of the Electric Grid – Phase II, D.P.U. 20-69-A (2021), including its proposal to treat any remaining book value associated with AMR at the time of full AMI implementation as a regulatory asset (Company Brief at 372, citing Exh. ES-REVREQ-1, at 204).

In response to the Attorney General, the Company argues that she simply restates her recommendations from D.P.U. 21-80, and that all the claims, arguments, and recommendations there were thoroughly rebutted (Company Brief at 372).[168] In particular, NSTAR Electric maintains that the Attorney General's arguments are based on flawed concepts and mischaracterizations of the Company's AMI Implementation Plan and proposed cost recovery mechanism (Company Brief at 374).

C. Analysis and Findings

1. Introduction

NSTAR Electric requested approval of its AMI Implementation Plan and model AMI tariff in D.P.U. 21-80 (Exhs. ES-REVREQ-1, at 200; ES-CAH/DPH-1, at 14, 109-110; ES-AMI-1, at 8, 16-19; DPU 7-1). In the instant proceeding, the Company seeks approval of the company-specific tariff that follows from, and is identical to, the model AMI tariff, but has been identified as company-specific (Exhs. ES-CAH/DPH-1, at 30; ES-AMI-1, at 11, 17; ES-AMI-2; ES-RDC-6, Sch. 1, at 556-561; DPU 7-1). Additionally, the Company proposes to recover any remaining book value of AMR meter costs at the time of AMI implementation through the establishment of a regulatory asset, and to establish a cost-of-service baseline for incremental O&M expense associated with AMI implementation (Exhs. ES-REVREQ-1, at 202-209; ES-AMI-1, at 20-22; ES-AMI-3). Concurrent with the instant Order, the Department approves NSTAR Electric's AMI Implementation Plan and a

[168] NSTAR Electric does not reiterate all of its positions in its brief, but notes that the Company's response to the Attorney General's contentions and recommendations can be found in pages 61 through 111 of the Company's initial brief filed on June 1, 2022, in D.P.U. 21-80, and pages three through 23 of the Company's reply brief filed on June 28, 2022, in the same docket (Company Brief at 374).

new AMIF reconciling mechanism, as well as directs modifications to the proposed model AMI tariff. D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 234, 238-239, 285-306. Because the only update to the model AMI tariff in the instant proceeding is the identification as company-specific, the Department adopts the findings from D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B and will not re-examine the arguments addressed therein.

2. AMR and Legacy Assets

As part of the Company's proposal, NSTAR Electric seeks approval to treat any remaining book value of AMR meter costs at the time of AMI implementation as a regulatory asset (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22; DPU 7-1; DPU 16-8; DPU 33-3, at 3; DPU 42-12). While the amount of remaining AMR meter costs at the time of AMI implementation is uncertain, the Company estimates a potential unrecovered AMR meter balance of approximately $21 million to $23 million at the end of 2028 (Exhs. DPU 9-1, at 2 & Att. (b); DPU 33-3, at 2 & Att. (b)).[169]

A regulatory asset is an incurred cost for which a regulatory agency such as the Department allows a regulated company to record a deferral to be considered for recovery in the future. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-54, at 318 n.235 (2010). See Bay State Gas Company, D.P.U. 15-50, at 6 n.10 (2015). A regulatory asset is created when regulators provide reasonable assurance of the

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169 The Company also suggested in testimony an unrecovered AMR balance upwards of $40 million at the end of AMI deployment (Exh. ES-AMI-1, at 22).

creation of an asset, i.e., when a company capitalizes all or part of an incurred cost that would otherwise be expensed and the regulators allow recovery of revenue at least equal to that cost. Western Massachusetts Electric Company, D.P.U. 94-8-CC (Phase I) at 12 n.13 (1994). NSTAR Electric does not seek to defer an incurred cost to be considered for future recovery, but instead essentially seeks approval to create and recover a potential regulatory asset with an amortization period determined by the amount of depreciation expense associated with AMR meters set in this proceeding (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22; DPU 9-1, Att. (b); DPU 16-8; DPU 42-11). Under the Company's proposal, once the regulatory asset is fully amortized, the amortization amount, equal to depreciation expense associated with AMR meters in base distribution rates, would be applied against the recovery of AMI costs in the recovery mechanism (Exhs. ES-REVREQ-1, at 204; ES-AMI-1, at 22; DPU 42-11). The Company's proposal therefore is for current approval for recovery of an unknown amount and amortization period.

While not included in NSTAR Electric's initial proposal, the Company suggests that to the extent that any similarly unrecovered costs related to legacy CIS and meter data management systems ("MDMS") remain, these costs would be treated as a regulatory asset in the same manner (Exh. DPU 46-3). The Company's CIS associated with WMA and EMA service areas were launched in 2008 and 1990, respectively, and have both been fully depreciated (Exh. DPU 9-2).[170] The Company notes, however, that it has made periodic

[170] While the Company could not identify the original book value of the CIS launched in 1990, software is typically depreciated over a period of three to ten years, and therefore all software installed by NSTAR Electric and ESC prior to 2010 has been

additional capital investments over time after the initial installations to address business needs and regulatory requirements and may need to make additional investments between today and the time AMI systems are fully installed (Exh. DPU 9-2). As such, any unrecovered costs or necessary retirements would be treated similarly to how the Company proposes to treat unrecovered AMI costs (Exhs. DPU 9-2; DPU 46-3). With respect to the Company's MDMS, NSTAR Electric anticipates the costs will be fully recovered in 2023 and 2027, but to the extent unrecovered costs remain they would be dealt with similarly (Exh. DPU 46-3).

The Department permits companies to establish regulatory assets in limited circumstances. D.P.U. 10-55, at 311. In this instance the Company's proposal is inconsistent with Department precedent because it seeks approval of cost recovery for potential, currently unknown, costs and a yet to be determined amortization schedule. Moreover, the Department has concerns regarding the potential for double recovery and overcollection of costs associated with the transition from AMR to AMI (Exh. DPU 9-1). During the proceeding, the Department explored the potential for under- or over-recovery of costs related to AMR and AMI implementation, as well as the Company's willingness to recover all AMR, AMI, CIS, and MDMS costs, i.e., meter-related capital, through the AMIF beginning on January 1, 2023 (Exhs. DPU 9-1; DPU 33-3; DPU 42-8; DPU 43-1; DPU 46-3; Tr. 7, at 713-718; RR-DPU-29). In evidentiary hearings as well as in response to discovery, the Company confirmed that it would not object to recovering all meter-related

fully depreciated; the original book value of the 2008 CIS was $9,612,342 and has been fully depreciated (Exhs. DPU 9-2; DPU 46-7).

capital through the AMIF, and that such treatment would eliminate the potential for over-recovery of costs, the need to establish any regulatory assets, and the need to recognize any offsets in the reconciling mechanism to coordinate between amounts still being recovered in base distribution rates (Exhs. DPU 43-1; DPU 46-3; Tr. 7, at 714-717; RR-DPU-29; RR-DPU-33). Based on these benefits, as well as the administrative efficiency of reviewing and recovering related costs through a single mechanism, the Department directs the Company to remove from base distribution rates all meter-related capital, and to instead recover them through the proposed reconciling mechanism. Accordingly, the Department directs the Company to reduce plant in service associated with Account 370 in the amount of $328,863,241, as well as the associated accumulated depreciation of $120,017,193 and ADIT in the amount of $50,123,051 (Exh. ES-REVREQ-3, WPs 25, 31 (Rev. 4); RR-DPU-29, Att. (e) at 1). An additional reduction is also required to O&M expense in the amount of $1,696,500[171] associated with the Company's legacy CIS and MDMS, and a reduction of $5,919,880 in property taxes (RR-DPU-29, Att. (a); RR-DPU-33).

3. Incremental O&M Baseline

NSTAR Electric calculates a test-year cost for metering and miscellaneous customer account expenses of $9.7 million, based on costs from FERC Accounts 586, 597, 902, and 905 (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24; ES-AMI-3, at 1; DPU 45-1). This

[171] The Company identified $1,712,485 as the annual recovery amount based on its proposed ROE (RR-DPU-29, Atts. (c) & (d)). This amount has been revised using the ROE approved by the Department in this Order and in accordance with the calculations applied to Enterprise IT expenses, discussed in Section VII.G.4 above.

amount represents the baseline amount of meter-related expenses NSTAR Electric will compare against in order to determine incremental cost recovery for AMI-meter related O&M as a component of the Company's reconciling mechanism (Exhs. ES-REVREQ-1, at 206; ES-AMI-1, at 24; ES-AMI-3, at 1). The Company proposes to track and document O&M costs required for AMI implementation and to recover as incremental costs the lesser of these costs or the net change to FERC Accounts 586, 597, 902, and 905 from the test amount of $9.7 million, adjusted each year for the annual change in GDP-PI (Exhs. ES-REVREQ-1, at 207; ES-AMI-1, at 24-25; DPU 45-2). NSTAR Electric acknowledges that there will be incremental O&M savings as well as costs and proposes to offset its requested incremental cost recovery by any AMI-related costs savings realized in the deployment of AMI (Exhs. ES-REVREQ-1, at 206-209; ES-AMI-1, at 25-26; ES-AMI-3, at 2). The Department has reviewed the identified categories and estimates of potential incremental costs and savings and finds that they are based on reasonable assumptions (Exhs. ES-REVREQ-1, at 207-209; ES-AMI-1, at 25-26; ES-AMI-3, at 2; DPU 45-1). Further, the Department finds that the Company's proposal for tracking incremental costs and savings ensures it will not double recover AMI related costs while appropriately accounting for inflation and potential savings (Exhs. ES-REVREQ-1, at 205-209; ES-AMI-1, at 25-26; ES-AMI-3, at 2; DPU 45-1; DPU 45-2). Therefore, the Department approves the Company's proposal for an incremental O&M expense baseline of $9.7 million, adjusted each year only for the annual change in GDP-PI, and directs NSTAR Electric to also account for actual AMI-related O&M savings as part of its reconciling mechanism filing.

4. Conclusion

Consistent with the Department's approval of NSTAR Electric's AMI Implementation Plan and AMI reconciling mechanism in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B, the Department approves the proposed company-specific AMI tariff, subject to the findings and modifications above and in D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B. Moving meter-related capital from base distribution rates to the Company's reconciling mechanism approved in D.P.U. 21-80-B/D.P.U. 21-81-B/ D.P.U. 21-82-B results in approximately $48.9 million being recovered through the AMIF effective January 1, 2023.[172] As designed, the AMIF will normally go into effect annually on July 1, and is intended to be in effect for a 12-month period through June 30 of the following year, but because the Department directs the Company to move all meter-related capital to the reconciling mechanism, the initial rate will go into effect January 1, 2023, to coincide with the establishment of new base distribution rates (RR-DPU-29). On May 15, 2024, the Company will file its annual AMIF to reconcile the revenue requirement associated with meters and existing CIS and MDMS systems for investment through December 31, 2023, including eligible AMI investments potentially incurred in 2022 (RR-DPU-29). D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 238 & n.95. As part of NSTAR Electric's compliance filing in the instant proceeding, the Department directs the Company to file an updated AMI tariff that is

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172 The Company identified $50,153,098 as the annual recovery amount based on its proposed ROE (RR-DPU-29, at 2 n.1). This amount has been revised using the ROE approved by the Department in this Order.

consistent with the Department's findings both herein and in D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B.

XVI. CAPITAL STRUCTURE AND COST OF CAPITAL

A. Introduction

NSTAR Electric proposes a 7.43-percent WACC representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exh. ES-REVREQ-2, Sch. 1, at 5, Sch. 33, at 1 (Rev. 4)). The Company's WACC comprises the following elements: (1) a capital structure consisting of 46.34 percent long-term debt, 0.45 percent preferred stock, and 53.21 percent common equity; (2) a long-term debt cost rate of 3.93 percent; (3) a preferred stock cost of 4.56 percent; and (4) an ROE of 10.50 percent (Exh. ES-REVREQ-2, Sch. 1, at 5 (Rev. 4)). The Attorney General proposes a 6.28-percent WACC based on the following components: (1) a capital structure consisting of 49.47 percent long-term debt, 0.53 percent preferred stock and 50.00 percent common equity; (2) a long-term debt cost rate of 3.60 percent; (3) a preferred stock cost of 4.56 percent; and (3) an ROE of 8.95 percent (Exhs. AG-JRW-1, at 5; AG-JRW-Surrebuttal-1, at 8).

B. Capital Structure

1. Introduction

At the end of the test year, NSTAR Electric reported a $3,670,000,000 long-term debt balance, a $43,000,000 preferred stock balance, and a $4,521,109,220 in common equity balance (Exh. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4)). The Company proposes:

(1) an increase of $800,000,000 to its long-term debt balance to reflect $1,450,000,000 in long-term debt issuances in 2021 and 2022[173] less the redemption of $650,000,000 in long-term debt issuances that reached maturity in 2021 and 2022; and (2) an increase of $612,000,000 to its common equity balance to reflect post test-year equity contributions from its parent company (Exh. ES-REVREQ-2, Sch. 33 (Rev. 4)). NSTAR Electric's adjustments result in a capitalization ratio of 46.34 long-term debt, 0.45 percent preferred stock, and 53.21 percent common equity (Exh. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4)).

The Attorney General proposes an imputed capital structure of 49.47 precent long-term debt, 0.53 percent preferred stock, and 50.00 percent common equity (Exhs. AG-JRW-1, at 31; JRW-4). The Attorney General states that an imputed capital structure aligns the Company with the capital structures of its parent company and the companies in the proxy groups (Exhs. AG-JRW-1, at 30-31; AG-JRW-Surrebuttal-1, at 7).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that NSTAR Electric's common equity ratio is higher than the average common equity ratios of the proxy groups of electric companies compiled by the Company and the Attorney General (see Sections XVI.D.1.a and Section XVI.D.1.b below) and higher than Eversource Energy's common equity ratio (Attorney General Brief

[173] On March 31, 2021, the Department authorized the Company to issue long-term debt securities in an amount not to exceed $1,600,000,000. NSTAR Electric Company, D.P.U. 20-146, at 27 (2021).

at 81, 84). The Attorney General claims that the Company is benefiting from "double leverage" because the parent company has a higher debt ratio than NSTAR Electric (Attorney General Reply Brief at 15). She argues that the solution to double leverage is to impute a more reasonable capital structure for the revenue requirement calculation or to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility (Attorney General Reply Brief at 16-17).

b. Company

The Company argues that its proposed common equity ratio is similar to common equity ratios recently approved by the Department (Company Brief at 252-253, citing, e.g., Exh. ES-VVR-Rebuttal-1, at 103-104; D.P.U. 17-05, at 623 (53.54 percent common equity)). Moreover, NSTAR Electric maintains that the Company's proposed common equity ratio is comparable to that of the average common equity ratio of the Company's proposed proxy group of electric companies, which was 54.80 percent (Company Brief at 253, citing Exh. ES-VVR-Rebuttal-1, at 101-102).

3. Analysis and Findings

A company's capital structure typically consists of long-term debt, preferred stock, and common equity. D.P.U. 07-71, at 122; 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. 07-71, at 122; 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 ROE set by the Department. D.P.U. 07-71, at 122; 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.T.E. 03-40, at 323-324; Boston Gas Company, D.P.U. 88-67 (Phase I) at 74 (1988); 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); 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, NSTAR Electric proposes to increase its test-year balance of long-term debt by $800,000,000 (Exhs. ES-REVREQ-1, at 144; ES-REVREQ-2, Sch. 33, at 1 (Rev. 4); DPU 10-1; Tr. 7, at 730-734). D.P.U. 20-146, Compliance Filing, Att. D (June 1, 2021); D.P.U. 20-146, Compliance Filing, Att. D (August 25, 2021); D.P.U. 20-146, Compliance Filing, Att. D (May 23, 2022); D.P.U. 20-146, Compliance

Filing, Att. D (September 16, 2022)). The Department finds that the Company's $800,000,000 long-term debt adjustment is a known and measurable change and accepts the Company's pro forma long-term debt balance of $4,470,000,000 (Exh. ES-REVREQ-2, Sch. 33 (Rev. 4)).

Turning to the Company's pro forma common equity balance, the Company proposes an increase of $612,000,000 to its test-year-end balance of common equity to reflect post-test-year capital contributions from Eversource Energy (Exhs. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4); DPU 10-2; Tr. 7, at 744). 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. 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. NSTAR Electric has demonstrated that the post-test-year capital contributions from Eversource Energy are known and measurable and that the capital contributions were necessary for the Company to maintain its financial metrics and credit rating (Exh. AG 1-11, Att. (d) at 7 (Supp.); Tr. 7, at 742-744). Therefore, the Department accepts the Company's pro form common equity balance of $5,133,109,220 (Exh. ES-REVREQ-2, Sch. 33, at 1 (Rev. 4)).

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 53.21 percent deviates substantially from sound utility practice. Rather, the Attorney General bases her position solely on her consultant's testimony that the Department must recognize that the Company's higher equity ratio reduces its financial risk by calculating its cost of capital using an imputed capital structure or authorizing a lower ROE (Attorney General at 84, citing Exh. AG-JRW-1, at 25-30). The consultant'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 do not conclude that such a ratio is so weighted towards equity as to deviate substantially from sound utility practice or impose an unfair burden on consumers. 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 (approving 53.91-percent and 54.51-percent common equity ratios and rejecting the Attorney General's imputed capital structures). Therefore, the Department will use a long-term debt balance of $4,470,000,000, a preferred stock balance of $43,000,000, and a common equity balance of $5,133,109,220 to determine NSTAR Electric's capital structure and cost of capital. The Department addresses the Company's financial risk compared to the proxy companies in Section XVI.D.3.g below.

C. Cost of Debt

1. Introduction

In its initial filing, the Company calculated a cost of debt of 3.60 percent (Exh. ES-REVREQ-2, Sch. 33, at 2). Based on the updates to its long-term debt balance discussed above, the Company proposes a long-term debt cost of 3.93 percent, which is calculated by dividing the annual interest payments by the principal amount of the issuances outstanding (Exh. ES-REVREQ-2, Schedule 33, at 2 (Rev. 4)). The Attorney General did not address the Company's updated cost of debt on brief.

2. Analysis and Findings

The Department has reviewed the Company's calculation of its proposed 3.93-percent cost of debt and determines that the cost of debt was properly calculated (Exh. ES-REVREQ-2, Sch. 33, at 2 (Rev. 4)). Therefore, the Department accepts the use of a 3.93-percent cost of debt for the purpose of determining the Company's WACC.

D. Return on Equity

1. Introduction

a. Company's Proposal

The Company's proposes a 10.50-percent ROE based on an analysis that considered the results of the constant growth discounted cash flow model ("DCF") and two risk premium models: (1) the capital asset pricing model ("CAPM"); and (2) the bond yield plus risk premium model ("RPM") (Exh. ES-VVR-1, at 5-6). These models are applied to the market data and financial information of two proxy groups of publicly-held companies

(Exh. ES-VVR-1, at 30-34).[174] The first proxy group comprises 15 publicly traded utility companies engaged in the business of electric distribution service ("Electric Proxy Group"),[175] and the second proxy group comprises twelve publicly-traded domestic companies with investment risk profiles that the Company represents are equivalent or lower than the Electric Proxy Group ("Non-Regulated Proxy Group") (Exh. ES-VVR-1, at 30-34).[176] In addition, NSTAR Electric's ROE analysis also considers the following factors to propose an ROE within the range of analytical results: (1) current and projected capital market conditions; (2) qualitative factors; and (3) the Company's proposed PBR plan (Exhs. ES-VVR-1, at 22, 37, 40; ES-CAH/DPH-1, at 110-117).

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[174] It is necessary to establish a group of publicly traded companies to serve as a proxy to estimate a market-based ROE because the Company is a wholly owned subsidiary of Eversource Energy and is not publicly traded (Exh. ES-VVR-1, at 21).

[175] The following were NSTAR Electric's selection criteria for the Electric Proxy Group: (1) an electric utility; (2) a safety rank of one, two, or three; (3) a corporate credit rating of at least BBB- or Baa3; (4) currently paying dividends without having discontinued or reduced dividends over the previous five years (2016-2020); (5) does not own nuclear power generation facilities; and (6) is not and has not recently been an acquisition target (Exh. ES-VVR-1, at 31).

[176] The following were NSTAR Electric's selection criteria for the Non-Regulated Proxy Group: (1) a conservative stock classification, meaning a safety rank no lower than one (2) a beta between 0.75 and 0.95; (3) a financial strength rating of A+ or higher; (4) a corporate credit rating of at least BBB- or Baa3; (5) not in the following businesses: gas and/or electric distribution, investment and financial services, pharmaceutical, life sciences, medical technology, hardware/software, or defense contracting; (6) currently paying dividends without having discontinued or reduced dividends over the previous five years (2016-2020); and (7) having at least one consensus earnings estimate published by an information service (Exh. ES-VVR-1, at 35).

In NSTAR Electric's DCF analyses, the required ROE equals the sum of the expected dividend yield and the expected long-term growth rate (Exh. ES-VVR-1, App. A). For the expected dividend yield, the Company uses the proxy companies' current annualized dividend and 30-day, 60-day, and 90-day average closing stock prices (Exhs. ES-VVR-1, App. A at 1; ES-VVR-3, at 3; ES-VVR-4, at 3). For the expected long-term growth rate, the Company uses projected earnings per share ("EPS") growth rates of the proxy companies provided by Thomson First Call (provided by Yahoo! Finance), Zacks Investment Research, and Value Line Investment Survey ("Value Line"), along with historical EPS growth rates provided by Value Line (Exhs. ES-VVR-1, at 48; ES-VVR-1, App. A at 5; ES-VVR-3, at 2; ES-VVR-4). The Company states that it excludes low-end and high-end outliers from its calculation of the mean DCF results to remove low cost of equity estimates that investors would not reasonably accept over corporate debt securities and high cost of equity estimates that reflect earnings growth that are not likely sustainable for regulated utility companies (Exhs. ES-VVR-1, at 7 & App. B, at 5; ES-VVR-3). In addition, the Company adjusts the model results to account for flotation costs[177] and includes a financial risk adjustment based on the difference between the market value and book value of the companies ("leverage adjustment") (Exhs. ES-VVR-1, at 48; ES-VVR-1, App. C; ES-VVR-1 App. D). After these adjustments,

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[177] Flotation costs are the costs incurred in issuing securities, also referred to as issuance costs. D.P.U. 85-266-A/85-271-A at 169; D.P.U. 19-120, at 354 n.172.

the Company's updated, mean DCF results are 9.68 percent for the Electric Proxy Group and 11.85 percent for the Non-Regulated Proxy Group (Exh. ES-VVR-Rebuttal-2, at 1, 2).[178]

The Company's CAPM includes three components to calculate the cost of equity: (1) a risk-free rate of return; (2) the proxy companies' beta coefficients, which are measures of systemic risk;[179] and (3) a market risk premium, which is the difference between market return estimates and the risk-free rate of return (Exh. ES-VVR-1, at 51). For the risk-free rate of return, NSTAR Electric uses average projected 30-year U.S. Treasury Bond yields from Blue Chip Financial Forecasts (Exhs. ES-VVR-1, at 55; ES-VVR-5, at 1; ES-VVR-Rebuttal-5, at 1).

The Company uses beta coefficients for the proxy companies published by Value Line with a leverage adjustment, which the Company states is necessary to reflect the difference between the companies' book value capital structure and market value capital structure (Exh. ES-VVR-1, at 60-61). NSTAR Electric's estimated market-return comprises a one-quarter weighting of a DCF analysis on the Standard and Poor's ("S&P") 500 Index, a one-quarter weighting of a DCF analysis on the Value Line 1,700 Stock Universe, and a one-half weighting of the historical Ibbotson Stocks, Bonds, Bills, and Inflation Yearbook annual total returns from 1926 to 2020 (Exhs. VVR-5, at 1-2; ES-VVR-Rebuttal-5, at 1-2).

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[178] In the Company's initial filing, the adjusted, mean DCF results were 9.78 percent and 11.70 percent, respectively (Exh. ES-VVR-1, at 78).

[179] A stock's beta measures the co-variability between the price movements of an individual stock and the price movements of the total market portfolio (Exh. ES-VVR-1, at 52).

In addition to the traditional CAPM results, the Company considers the CAPM results with a size adjustment published by Duff & Phelps and the results of the empirical CAPM, which applies a 75-percent weighting to the product of the beta coefficient and the market risk premium and a 25-percent weighting to the market risk premium alone (Exh. ES-VVR-1, at 63-66). For the Electric Proxy Group, after applying an adjustment for flotation costs, the Company's updated traditional, size adjusted, and empirical CAPM results range from 11.39 percent to 11.88 percent (Exh. ES-VVR-Rebuttal-2, at 3).[180] For the Non-Regulated Proxy Group, after applying an adjustment for flotation costs, the Company's traditional, size adjusted, and empirical CAPM results range from 10.95 percent to 11.25 percent (Exh. ES-VVR-Rebuttal-2, at 3).[181]

In NSTAR Electric's RPM, the cost of equity equals the sum of the Company's prospective cost of debt and expected equity risk premium (Exh. ES-VVR-1, at 67-68). For the Electric Proxy Group, the Company uses an average of equity risk premiums, including: (1) historic returns for the S&P 500 Composite Index less historic long-term corporate bonds; (2) the prospective equity risk premium used in the CAPM described above; (3) historic returns for the S&P Utilities Index less historic utility bond yields; and (4) a DCF analysis of the S&P 500 Utilities Index less the three-month average of Moody's Investors Service Inc.'s

180 In NSTAR Electric's initial filing, the Electric Proxy Group CAPM results ranged from 10.77 percent to 11.26 percent (Exh. ES-VVR-1, at 78).

181 In the Company's initial filing, the Non-Regulated Proxy Group CAPM results ranged from 10.34 percent to 10.64 percent (Exh. ES-VVR-1, at 78).

"(Moody's") A-rated public utility bond yields (Exh. ES-VVR-6, at 1-5). For the Non-Regulated Proxy Group, the Company uses an average of equity risk premiums, including historic returns for the S&P 500 Index less historic long-term corporate bonds and the prospective equity risk premium used in the CAPM described above (Exh. ES-VVR-6, at 7-8). After applying an adjustment for flotation costs, the updated RPM calculations produce ROE estimates of 10.84 percent for the Electric Proxy Group and 11.37 percent for the Non-Regulated Group (Exh. ES-VVR-Rebuttal-2, at 4).[182]

b. Attorney General's Proposal

To develop her rate of return recommendation, the Attorney General considers the results of a constant growth DCF analysis and a CAPM applied to a proxy group of 24 publicly held electric utility companies ("Attorney General Proxy Group") (Exhs. AG-JRW-1, at 22-23; JRW-3).[183] In addition, the Attorney General considers capital market conditions and the trend in authorized ROEs (Exh. AG-JRW-1, at 9-22). The Attorney General's DCF results are 8.80 percent for the Attorney General Proxy Group and

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[182] In the Company's initial filing, the RPM calculations produced ROE estimates of 10.66 percent for the Electric Proxy Group and 10.75 percent for the Non-Regulated Proxy Group (Exh. ES-VVR-1, at 78).

[183] The following were the Attorney General's selection criteria for her proxy group: (1) has at least 50 percent of revenues from regulated electric operations as reported in its Form 10-K filed with the U.S. Securities Exchange Commission; (2) is listed as a U.S.-based electric utility; (3) has an investment grade issuer credit rating by Moody's and S&P; (4) has paid a cash dividend in the past six months with no reductions or omissions; (5) has not been involved in an acquisition of another utility, nor has been the target of an acquisition in the past six months; and (6) has analysts' long-term EPS growth rate forecasts available (Exh. AG-JRW-1, at 22-23).

8.95 percent for the Electric Proxy Group (Exh. AG-JRW-1, at 56). For the CAPM, the Attorney General uses a market risk premium based on a review of studies and surveys, which produces an ROE estimate of 7.70 percent (Exh. AG-JRW-1, at 64-68). The Attorney General concludes that 7.70 percent to 8.95 percent represents a reasonable range of ROEs for NSTAR Electric and recommends an 8.95-percent ROE at the top of the range, giving primary weight to the DCF results and accounting for the recent rise in interest rates (Exh. AG-JRW-1, at 4, 71).

c. UMass Proposal

UMass recommends a 9.25-percent ROE based on an analysis of authorized returns for New England investor-owned utilities (Exh. UMASS-EP/RS-1, at 53-58). UMass states that an ROE of 9.25 percent would not threaten NSTAR Electric's financial integrity and ability to raise capital on reasonable terms (Exh. UMASS-EP/RS-1, at 58).

2. Positions of the Parties

a. Attorney General

i. Proxy Groups

The Attorney General asserts that the Attorney General Proxy Group and Electric Proxy Group are similar in risk based on six measures, including credit ratings, beta, financial strength, safety, earnings predictability, and stock price stability (Attorney General Brief at 87, citing Exh. AG-JRW-1, at 23). The Attorney General contends that the Department generally rejects the results of non-regulated proxy groups (Attorney General Brief at 86, citing D.T.E. 01-56, at 116; D.P.U. 96-50 (Phase I), at 132; D.P.U. 92-250, at 160-161; D.P.U. 905, at 48-49). The Attorney General claims that the companies in the Non-Regulated Proxy Group are very different from the electric distribution business and none of them operate under a regulatory construct like the electric distribution business (Attorney General Brief at 87). The Attorney General argues that the Department should not consider the Non-Regulated Proxy Group in its determination of the Company allowed ROE[184] (Attorney General Brief at 88).

ii. ROE Estimation Models

(A) DCF

The Attorney General contends that the Department should reject the Company's DCF analysis as it contains several substantive flaws that overstate the estimated cost of equity (Attorney General Brief at 81). First, she argues that the Company's outlier test eliminates low-end outliers while not affecting high-end outliers in the Electric Proxy Group (Attorney General Brief at 90). She claims that the asymmetric elimination of low-end outliers creates an upwardly biased estimate (Attorney General Brief at 90; Attorney General Reply Brief at 20). In addition, the Attorney General asserts that the Company relies solely on overly optimistic and upwardly biased EPS growth rates of Wall Street analysts and Value Line (Attorney General Brief at 90-92; Attorney General Reply Brief at 20).

The Attorney General also maintains that the Company's leverage adjustment is unwarranted (Attorney General Brief at 92-93). She claims that the market value of a firm's

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184 Throughout this Order, the Department uses the terms authorized and allowed interchangeably.

equity is greater than the book value due to the firm's earning a return that is more than its equity costs (Attorney General Brief at 93). The Attorney General avers that the adjustment is unnecessary as there is no change in the Company's leverage, and its financial statements and fixed financial obligations remain the same (Attorney General Brief at 93). She contends that financial publications and investment firms report capitalizations on a book value basis, not on a market value basis (Attorney General Brief at 93). Further, Attorney General argues that regulatory commissions have rejected leverage adjustments because they increase ROEs for utilities that have high returns on common equity and decrease ROEs for utilities that have low returns on common equity (Attorney General Brief at 93).

Finally, the Attorney General contests the Company's flotation cost adjustment to its DCF results (Attorney General Brief at 93). She maintains that the Company has not provided evidence that flotation costs have been paid (Attorney General Brief at 92). In addition, she asserts that the Department has previously rejected the inclusion of issuance costs in the determination of ROE (Attorney General Brief at 92, citing D.P.U. 17-05, at 705-706; 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). The Attorney General argues that the Company has not provided sufficient evidence to change Department precedent (Attorney General Brief at 94).

(B) CAPM and RPM

The Attorney General contends that the major issue with the CAPM is the measurement and magnitude of the market premium (Attorney General Brief at 96). The Attorney General asserts that the Department should use a market risk premium no higher than 5.50 percent in any CAPM analysis used to determine NSTAR Electric's cost of equity (Attorney General Brief at 96). Further, she argues that there are five primary errors with the Company's CAPM: (1) the market risk premium of 7.50 percent; (2) the use of the empirical CAPM; (3) the size adjustment; (4) the use of leverage-adjusted betas; and (5) the flotation adjustment (Attorney General Brief at 96-105).

The Attorney General contends that the most significant error in the Company's CAPM is the market risk premium (Attorney General at 99). She avers that the Company's approach in computing its historical market risk premium suffers from several flaws, including stock market survivorship bias, the use of the arithmetic mean of stock price returns, an inappropriate time horizon, a failure to recognize changes in risk and return over time, a downward bias in historical bond returns, and unattainable return bias (Attorney General Brief at 99-100, citing Exh. AG-JRW-1, at 85-89). The Attorney General also claims that the Company's prospective market risk premium relies on the same biased EPS growth rates used in the Company's DCF analyses that are inconsistent with both historic and projected economic and earnings growth as reflected in projections of gross domestic product ("GDP") growth (Attorney General Brief at 100-102, citing Exh. AG-JRW-1, at 89-95; Attorney General Reply Brief at 21-23). Further, the Attorney General asserts that the Company's market risk premium component of the RPM contains the same flaws and should also be rejected (Attorney General Brief at 106).

The Attorney General also objects to the use of the empirical CAPM to estimate the Company's required ROE (Attorney General Brief at 98). She asserts that: (1) the empirical

CAPM has not been theoretically or empirically validated in refereed journals; and (2) the adjusted betas from Value Line already address the purported empirical issues with the CAPM (Attorney General Brief at 98, citing Exh. AG-JRW-1, at 83-84).

Additionally, the Attorney General argues that the size premium adjustment made by the Company is inappropriate and should be rejected (Attorney General Brief at 103-105). She notes that the size premiums are poor measures for size adjustments as they fail to account for survivorship and unattainable return biases (Attorney General Brief at 103-104). According to the Attorney General because public utilities are closely regulated, must gain approval for financial transactions, have standardized accounting and reporting requirements, and have earnings that are, to an extent, predetermined by the ratemaking process, their stocks do not exhibit a significant size premium (Attorney General Brief at 104). The Attorney General further argues that the Company's upward adjustments of betas to compensate for the difference between book value and market value capitalization suffers from the same flaw as the adjustment it made in its DCF analysis (Attorney General Brief at 98, citing Exh. AG-JRW-1, at 83-84).

iii. Required ROE

The Attorney General also argues that her 7.70-percent to 8.95-percent range of reasonable ROEs and 8.95 percent ROE recommendation are supported by current capital market conditions and a trend of declining authorized ROEs for other electric distribution companies (Attorney General Brief at 79-80, 95, 111-112; Attorney General Reply Brief at 13-14, 25-27). Specifically, she maintains that despite short-term expectations of higher inflation, the long-term inflation rate is still 2.50 percent (Attorney General Brief at 108). Further, the Attorney General avers that: (1) authorized ROEs for distribution companies nationally have trended downward since 2012, coinciding with decreasing interest rates; (2) Massachusetts ROEs have trended upward while the national averages have moved downward; and (3) the differences between Massachusetts and national average ROEs have become larger in recent years (Attorney General Brief at 110-111, citing Exh. AG-JRW-1, at 18-21; Attorney General Reply Brief at 26).

In addition, the Attorney General asserts that the investment risk of the Company is below the investment risk of the Electric Proxy Group because the Company has a higher credit rating and higher equity ratio (Attorney General Brief at 81, 84-85). She claims that the Company overestimates its required ROE by assuming NSTAR Electric is riskier than the Electric Proxy Group (Attorney General Brief at 80-83, 112; Attorney General Reply Brief at 18). The Attorney General avers that the electric distribution industry overall is among the lowest risk industries in the nation as measured by beta and, therefore, the industry's risk has declined (Attorney General Brief at 80, citing Exh. JRW-6).

Moreover, the Attorney General argues that NSTAR Electric's proposed PBR plan decreases the Company's financial risk relative to the proxy companies due to the exogenous cost factor and the rate adjustments (Attorney General Brief at 83, citing Exh. AG-JRW-1, at 8-9). Further, she contends that the stay-out provision of the PBR plan does not increase the Company's risk because the Company can break the stay-out provision (Attorney General Brief at 83 n.82, citing Exh. AG-JRW-1, at 8; D.P.U. 17-05, at 403-404 (2017)).

Finally, the Attorney General argues that the Department should reject the Company's request for an allowed ROE at the higher end of the reasonable range because of NSTAR Electric's quality of service (Attorney General Reply Brief at 29-30). The Attorney General asserts that the Company disingenuously claims that its PBR plan benefitted customers because, according to the Attorney General, the Company merely shifted costs from O&M by adjusting the capitalization rate (Attorney General Brief at 21-22; Attorney General Reply Brief at 30).

b. Acadia Center

Acadia Center agrees with UMass's recommendation of a 9.25-percent ROE (Acadia Center Brief at 9). Acadia Center argues that the allowed ROE should be significantly lower than the 10.5 percent proposed by the Company (Acadia Center Brief at 8). Acadia Center argues that comparable New England distribution companies can attract capital at lower rates without experiencing financial distress (Acadia Center Brief at 9).

c. Conservation Law Foundation

CLF argues that the Company's proposed ROE is unreasonably high and results in rates that are not just and reasonable (CLF Brief at 8). Further, CLF contends that the Company has failed to adequately explain why an increase in an already high ROE is warranted (CLF Brief at 8). CLF asserts that it is unreasonable for NSTAR Electric ratepayers to pay more than their neighbors for the same type of electric service and investments, subject to the same capital markets (CLF Brief at 8).

d. UMass

UMass argues that NSTAR Electric's proposed ROE is not commensurate with the return authorized for other New England EDCs or the national averages for electric rate cases in 2021 and the first quarter of 2022 (UMass Brief at 3, 35; UMass Reply Brief at 9-11). UMass contends that a 9.25-percent ROE reflects a level of return that the Company's peers have demonstrated to be sufficient to successfully provide similar services, maintain financial integrity, and attract capital (UMass Brief at 36; UMass Reply Brief at 9-11). UMass avers that experience in the region clearly demonstrates that an allowed ROE of 9.25 percent is sufficient to maintain financial integrity and to allow the firm to attract capital on reasonable terms (UMass Brief at 40, citing Exh. UMASS-EP/RS-1, at 57-58; Tr. 10, at 1150-1152).

e. Company

i. Proxy Groups

NSTAR Electric argues that, in determining its ROE, it has used appropriate proxy groups that include companies that: (1) are based on valid selection criteria; and (2) have sufficient financial and operating data to discern the investment risk of NSTAR Electric versus the comparison groups (Company Brief at 258, citing D.P.U. 20-120, at 413). The Company maintains that the objective in developing a proxy group is to develop a group of companies that are fundamentally similar with respect to operating, financial, and business risks of the utility seeking rate relief (Company Brief at 258-259, citing D.P.U. 08-35, at 176). NSTAR Electric claims that the companies in the Non-Regulated Proxy Group are comparable because they are lower risk consumer staple, food and beverage, chemicals processing, and transportation companies, which, like utilities, are less susceptible to changes in the business cycle (Company Brief at 259-260, 272, citing Exhs. ES-VVR-1, at 35; VVR-Rebuttal-1, at 91; Company Reply Brief at 28). Further, NSTAR Electric asserts that the Department has accepted the use of a non-regulated proxy group in setting the ROE (Company Brief at 260, 273, citing D.P.U. 13-75, at 302, 328; D.P.U. 12-25, at 416-17, 441). Finally, the Company maintains that the Attorney General's Proxy Group is too limited because it does not include comparable non-regulated companies (Company Brief at 272).

ii. ROE Estimation Models

(A) DCF

NSTAR Electric argues that the DCF analysis underestimates the Company's cost of equity because of the impact of recent long-term interest rates on the dividend yield (Company Brief at 262, citing Exh. ES-VVR-1, at 15-17, 48-49; Company Reply Brief at 27-28). The Company claims that investors view utility stocks as substitutions for fixed-income securities and that the recent downward pressure on long-term interest rates resulted in increased demand for utility stocks, raising utility stock prices and suppressing dividend yields (Company Brief at 262, citing Exh. ES-VVR-1, at 15-17, 48-49; Company Reply Brief at 27-28).

With respect to expected growth rates, the Company asserts that it correctly relies on EPS growth rates because a substantial amount of academic research has demonstrated that equity analyst forecasts have a significant influence on the growth expectations of investors (Company Brief at 260, citing Exh. ES-VVR-1, App. A at 2-3). The Company further argues that the Department should reject the Attorney General's claim that EPS growth rates are overly optimistic and upwardly biased consistent with the Department's prior findings on this issue (Company Brief at 275, citing Exh. ES-VVR-Rebuttal-1, at 35-37; D.P.U. 20-120, at 420; D.P.U. 19-120, at 374; Company Reply Brief at 27).

In addition, NSTAR Electric contends that it eliminated low-end and high-end outliers from the mean DCF results considered in the proposed ROE because those results did not pass fundamental tests of economic logic (Company Brief at 260-261, citing Exh. ES-VVR-1, App. B at 1-2). The Company reasons that rational investors will not invest in common stocks if the expected return is lower than or marginally higher than yields available on corporate debt securities (Company Brief at 260-261, citing Exh. ES-VVR-1, App. B at 2)

Finally, the Company argues that the Department should adopt the Company's adjustments to the DCF results to reflect the difference between market value and book value and to account for flotation costs (Company Brief at 261). The Company maintains that a leverage adjustment is necessary when the average market value equity capitalization of the proxy group companies is materially higher than the corresponding book value equity capitalizations (Company Brief at 261, citing Exh. ES-VVR-1, at App. C at 1-4). NSTAR Electric contends that the flotation adjustment accounts for the various costs incurred in the issuance of new equity stock (Company Brief at 261, citing Exh. ES-VVR-1, App. D at 1).

(B) CAPM and RPM

NSTAR Electric maintains that it ensured a balanced approach to estimate a market risk premium for the CAPM by using historical and prospective data and that the prospective market risk premium was calculated consistent with the Department's directives in D.P.U. 20-120, at 429-430 (Company Brief at 262-263). The Company argues that its market risk premium is reasonable and that the Attorney General's objections to the Company's calculation of the market risk premium are without merit (Company Brief at 280). Specifically, the Company maintains that the forecasted EPS growth rate for the S&P 500 is a reasonable market-based estimate that has been accepted by other utility commissions and is consistent with historical returns (Company Brief at 281).

The Company also asserts that it considers a size-adjusted CAPM based on academic studies that have shown small capitalization stocks have historically earned returns that are materially higher than returns predicted by the traditional CAPM (Company Brief at 264). In addition, the Company contends that it considers the empirical variant of the CAPM because extensive empirical evidence has shown that the risk-return relationship between beta and stock returns is flatter than what is predicted by the traditional CAPM (Company Brief at 264, citing Exh. ES-VVR-1, at 65). Further, the Company argues that it applies leverage and flotation adjustments to the CAPM results for the same reasons that those adjustments were applied to the DCF results (Company Brief at 263, citing Exhs. ES-VVR-1, at 60-66; ES-VVR-Rebuttal-1, at 5).

With respect to the RPM, NSTAR Electric argues that the Department relies on the RPM as a supplemental approach in determining the level of ROE (Company Brief at 282, citing D.P.U. 07-71, at 137). For the same reasons discussed above in relation to the market risk premium used in the CAPM, the Company claims that the Attorney General's objections to the market risk premium used in the RPM have no merit (Company Brief at 282). The Company avers, therefore, that the Department should at least supplement its calculation of the Company's ROE with the risk premium approach (Company Brief at 282).

iii. Required ROE

The Company maintains that its proposed ROE reflects capital market conditions and is the result of applying widely accepted common equity cost models (Company Brief at 292). NSTAR Electric argues that it is critical for the Department to recognize that the allowed ROE must position the Company to attract capital on a going-forward basis because it will not be able to maintain safe and reliable service without a fair return (Company Brief at 255). NSTAR Electric asserts that based on the legal standard for authorizing an ROE and the evidence in this proceeding, the Department should adopt the Company's recommended ROE of 10.50 percent (Company Brief at 255-256, 292).

In support of its requested ROE, NSTAR Electric also contends that the Department's decision must account for the recent increases in interest rates and inflation (Company Reply Brief at 25). The Company asserts that as interest rates have increased, and continue to increase, the cost of equity also increases (Company Reply Brief at 26, citing Tr. 14, at 1433, 1436-1439, 1441-1443; RR-DPU-40, Att. at 1; RR-ES-1).

Further, the Company claims that the intervenors' recommended ROEs based on national and regional authorized ROEs have no merit (Company Brief at 284-285, 288-291; Company Reply Brief at 22, 30, 32-34). NSTAR Electric argues that the Department should not rely on the 2021 and 2022 national averages for allowed ROEs or current authorized ROEs in New England because the sample sizes of these decisions are too small to be reliable, the national averages are skewed by jurisdictions that use formulaic approaches to determine an allowed ROE, and setting an allowed ROE based on averages from prior years would ignore the recent dramatic increase in interest rates and inflation (Company Brief at 284-285, 289-291, citing Tr. 9, at 1004-1006; Company Reply Brief at 22, 33, citing Exh. ES-VVR-Rebutal-1, at 18; Tr. 14, at 1437-1443; RR-DPU-40, Att. at 1; RR-ES-1, Att.).

With respect to credit rating, the Company maintains that the Department should reject the Attorney General's proposal to lower the Company's ROE based on a comparison to the proxy companies' credit ratings (Company Reply Brief at 24). NSTAR Electric asserts that there is no evidence showing a nexus between credit ratings and the specific, authorized cost of equity set for utilities and that the Department has rejected adjustments based on credit rating in the past (Company Reply Brief at 24, citing D.P.U. 20-120, at 430; D.P.U. 09-30, at 363, 365).

Turning to the proposed PBR plan, the Company argues that the proposed ten-year stay-out provision increases the Company's risk and, therefore, the Department should establish an ROE at the higher end of the reasonable range (Company Brief at 267, 283-284).

In particular, NSTAR Electric asserts that a "stay-out provision as part of a PBR plan may increase a company's risks in meeting its financial requirements" (Company Brief at 265, 284, citing D.P.U. 20-120, at 431-432; Company Reply Brief at 25). The Company further claims that the Department has found that a ten-year stay-out provision as part of a company's PBR mechanism increases the risks in meeting its financial requirements (Company Brief at 265, 284, citing D.P.U. 19-120, at 405).

Moreover, the Company avers that the electric utility industry is facing regulatory uncertainty associated with changes necessary to help achieve reductions in GHG emissions (Company Brief at 266, citing Exh. ES-CAH/DPH/ANB-1, at 116; Company Reply Brief at 25). NSTAR Electric contends that the changes will require significant increases in capital expenditures and will create regulatory uncertainty (Company Brief at 266; Company Reply Brief at 25).

Finally, NSTAR Electric argues that its ROE should be set at the higher end of the reasonable range based on qualitative factors (Company Brief at 267; Company Reply Brief at 31). The Company asserts that it has excellent service quality and exceeded its benchmarks during its current PBR plan (Company Brief at 267, citing Exh. ES-CAH-DPH-1, at 111). The Company also claims that it is a top performer in the industry with respect to reliability and customer service (Company Brief at 267-268, citing Exh. ES-CAH-DPH-1, at 112; Company Reply Brief at 31). Further, the Company maintains that during its current PBR plan the Company contained O&M costs to the direct benefit of customers and excelled at storm restoration (Company Brief at 267-268, citing Exh. ES-CAH-DPH-1, at 112-114; Company Reply Brief at 31-32).

3. Analysis and Findings

a. Proxy Groups

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. 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 NSTAR Electric (Exh. ES-VVR-1, at 32). 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[185] and must be generally comparable in investment risk. 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 NSTAR Electric in every detail. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; 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 NSTAR

185 An important aspect of the criteria for a proxy group is that financial information is readily available for publicly traded companies.

Electric relative to the proxy group. 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 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. 10-55, at 480-482. The Department has previously found that overly exclusive selection criteria may affect the statistical reliability of a proxy group, especially if such screening criteria result in a limited number of companies in the proxy group. D.P.U. 10-55, at 480-482.[186] The Department has directed parties to limit criteria to the extent necessary to develop a broader as opposed to a narrower proxy group. 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. 10-114, at 299; 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. 90-121, at 166.

After review, the Department finds that NSTAR Electric and the Attorney General each employed a set of valid criteria to select the Electric Proxy Group and Attorney General

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186 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. <u>In Re Public Service Company of New Hampshire</u>, 90 NH PUC 230, 247 (2005).

Proxy Group, and the Department finds that both parties provided sufficient information to draw conclusions about the relative risk characteristics of the Company versus the members of the proxy groups (Exhs. ES-VVR-1, at 30-31; AG-JRW-1, at 22-23; AG-JRW-3). D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will accept the Company's Electric Proxy Group and the Attorney General Proxy Group to determine NSTAR Electric's allowed ROE.

Periodically, companies have proffered a comparable earnings approach to estimate ROE as a supplement to DCF and risk premium analyses. D.T.E. 01-56, at 113-116. The comparable earnings approach uses both historical returns and forecasted returns for a group of non-utility companies, which proponents of this approach have selected based on financial risk criteria from resources such as Value Line, Moody's, and S&P. D.P.U. 13-75, at 320; D.P.U. 12-25, at 433-436; D.P.U. 08-35, at 208-211; D.T.E. 01-56, at 113-116. Therefore, the comparable earnings approach is similar to NSTAR Electric's proposal to estimate its ROE based on DCF and risk premium analyses using historical and forecasted data of the Non-Regulated Proxy Group, which was selected based on similar financial risk criteria (Exhs. ES-VVR-1, at 32-37; ES-VVR-4; ES-VVR-5; ES-VVR-6). The Department has generally rejected the results of the comparable earnings analysis on the basis that the financial risk criteria provided by the proponents, including beta, financial strength, price stability, and credit rating, were not sufficient to establish the comparability of the non-price-regulated firms with the distribution company being considered. D.P.U. 13-75, at 321-322; D.P.U. 12-25, at 435-436; D.P.U. 08-35, at 210; D.T.E. 01-56, at 113-116.

After review, we find that NSTAR Electric's proposal to rely on a Non-Regulated Proxy Group suffers from similar limitations to those identified with respect to the comparable earnings approach. The Department has repeatedly found that the use of beta as a criterion in selecting a comparable group of companies is not a reliable investment risk indicator given its statistical measurement limitations. D.P.U. 13-75, at 321-322; D.P.U. 12-25, at 435; D.P.U. 08-35, at 210; D.T.E. 01-56, at 113-116. The Department also has found that the financial risk criteria employed by NSTAR Electric do not fully capture the value of operating a regulated monopoly in a revenue decoupled market. D.P.U. 13-75, at 321-322; D.P.U. 12-25, at 435. Moreover, while NSTAR Electric correctly states that we must ensure a proxy group of companies is fundamentally similar with respect to the operating, financial, and business risks of the utility, the Company provided little evidence concerning how the operating and business risks of the Non-Regulated Proxy Group are similar to an electric distribution company, other than opinion testimony, which contrasts with the Attorney General's opinion testimony (Exhs. ES-VVR-1, at 35; ES-VVR-Rebuttal-1, at 91; AG JRW-1, at 74; Tr. 9, at 1047).[187] D.P.U. 08-35, at 176.

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[187] Further, in the Company's testimony it stated that the Non-Regulated Proxy Group behaved similarly to utility companies in the business life cycle, but during evidentiary hearings the Company represented that the business life cycle did not apply to utilities at all, which creates further uncertainty that the Non-Regulated Proxy Group is comparable to NSTAR Electric (Exh. ES-VVR-Rebuttal-1, at 91; Tr. 9, at 1047).

NSTAR Electric correctly identifies two instances in which the Department has considered ROE estimates based on non-regulated companies in our determination of a utility's allowed ROE. D.P.U. 13-75, at 286-287; D.P.U. 12-25, at 402. The Company, however, does not present a complete picture of the Department's analysis in those cases. NSTAR Electric 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.[188] Ultimately, the Department authorized ROEs in those Orders that were, respectively, 303 basis points and 251 basis points lower than the 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.

Based on the findings above, while there is some evidence that the Non-Regulated Proxy Group has similar financial risk to NSTAR Electric, the Company has provided limited evidence demonstrating that the consumer staple, food and beverage, chemicals processing, and transportation companies have comparable operations and business risk to an electric distribution company (Exhs. ES-VVR-1, at 35; VVR-Rebuttal-1, at 91). Therefore,

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188 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.

the Department will place limited weight on the ROE estimates based on the Non-Regulated Proxy Group in our determination of the allowed ROE.

b. ROE Estimation Models

i. DCF Model

The DCF is a commonly used valuation model based on the fundamental premise that investors value financial assets on the basis of expected future cash flows, discounted by an appropriate risk-adjusted rate of return (Exhs. ES-VVR-1, at 42; AG-JRW-1, at 39). As discussed above, both the Company and the Attorney General rely on DCF analyses to recommend an allowed ROE (Exhs. ES-VVR-1, at 5; AG-JRW-1, at 6). The parties disagree on three key issues regarding their respective DCF analyses: (1) the impact of current market conditions on the DCF results; (2) the appropriate estimated growth rate; and (3) the Company's adjustments to the DCF analysis for flotation costs, the leverage adjustment, and outliers.

The Department recently considered the relationship between low interest rates and utility stock prices over the last several years and whether a projected increase in long-term interest rates caused the DCF analysis to understate the cost of equity. D.P.U. 20-120, at 416-419. The Department found that, although utility stocks had increased above historic levels in conjunction with low interest rates, the evidence in that proceeding that long-term interest rates would change was speculative. D.P.U. 20-120, at 417-419. In this proceeding, the record is clear that long-term interest rates have increased compared to the period of time from which the parties derived the dividend yields used in the DCF analyses

(Exh. ES-VVR-Rebutal-1, at 23-26; Tr. 14, at 1463). We also have considered the Attorney General's evidence of investors forecasting that utility stocks will retain their high valuations in the near term (Tr. 14, at 1449-1452; RR-DPU-48). Based on the foregoing evidence, the Department finds that there is greater certainty that the DCF results understate the Company's cost of equity. The Department takes these findings into consideration in the determination of the reasonable range below.

Determining the appropriate long-term growth expectations of investors in a DCF analysis is often difficult and controversial. D.P.U. 15-155, at 365. As discussed above, the Company and Attorney General use different growth rates in their respective DCF analyses, and each party objects to the other's choice of growth rates. Regarding EPS growth rates, the Department has previously found that federal regulators have mitigated the systemic bias in overly optimistic stock recommendations, and the Department has accepted DCF results that rely on EPS growth rates. D.P.U. 20-120, at 419-420; D.P.U. 19-120, at 374. We reaffirm those findings.

The Company uses EPS growth rates between 5.20 percent and 5.60 percent for the Electric Proxy Group (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2). The Attorney General uses a growth rate of 5.50 percent for the Attorney General Proxy Group and a growth rate of 5.75 percent for the Electric Proxy Group (Exh. AG-JRW-1, at 54-55). Based on our precedent and the supporting evidence provided by the parties, the Department finds that both the Company's and the Attorney General's approaches to the expected growth rates are reasonable (Exhs. ES-VVR-1, App. A at 3-10; AG-JRW-1, at 45-55).

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. 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 found in several Orders that investors already take into account issuance costs in their decision to purchase a stock at a given price. 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 finds that NSTAR Electric has failed to present any evidence or argument to justify a departure from long-standing precedent (Exh. DPU 10-16). Accordingly, the Department will not rely on the Company's DCF results without adjustment for flotation costs in the determination of the reasonable range.

The Department has also consistently rejected leverage adjustments (Exhs. ES-VVR-1, at 48; ES-VVR-1, App. C). D.P.U. 10-55, at 513; D.P.U. 09-39, at 387; D.T.E. 05-27, at 298; D.T.E. 03-40, at 357-359; D.T.E. 01-56, at 105-106; D.P.U. 906, at 100-101; Eastern Edison Company, D.P.U. 837/968, at 49 (1982). The Company's proposed leverage adjustment relies on a comparison between book and market capitalization and, therefore, has similar elements to the price-book ratio method of determining a utility's cost of equity. D.T.E. 01-56, at 105. The Department has frequently rejected the price-book analysis because it fails to recognize variables such as a company's geographic location, load factors, and customer make-up, which can affect price-book ratios. D.T.E. 01-56, at 105, citing D.P.U. 906, at 100-101. Additionally, the price-book analysis has been found to rely excessively on investor perceptions of the relationship between market and book prices in their investment decisions. D.T.E. 01-56, at 105, citing D.P.U. 837/968, at 49.

These weaknesses of the price-book ratio analysis are also present in NSTAR Electric's leverage adjustment. The Company asserts that investors require a higher return because the book value of their investment is exceeded by its market value (Exh. ES-VVR-1, App. C, at 1). Considering the multiplicity of factors that affect investor decisions on the valuation of a utility's common stock, the Department considers the Company's market/book analysis as an implicit attempt to automatically ensure a market-to-book ratio of one-to-one. This automatic assurance would serve to remove an inherent aspect of utility management, that is, to "bear the brunt of inefficient decisions and reap the rewards of efficiency." D.T.E. 01-56, at 106, citing D.P.U. 906, at 100. The Department is not obligated to ensure that market-to-book ratios remain on a one-to-one basis. The Department finds that NSTAR Electric has failed to present any evidence or argument to justify a departure from long-standing precedent (Exh. DPU 10-15). Therefore, the Department places no weight on the Company's proposed leverage adjustment.

Finally, the Company applied low-end and high-end outlier thresholds to the DCF results (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2). While the Department has concerns that the design of NSTAR Electric's outlier test could lead to asymmetrical results that skew the cost of equity estimate, in this particular case, the Company's DCF results screened for outliers are comparable to the Attorney General's DCF results without a screen for outliers (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2; AG-JRW-1, at 55; Tr. 14, at 1474).

The Company's updated mean DCF results for the Electric Proxy Group, without the adjustments for flotation costs or the leverage adjustment, range from 8.50 percent to 9.20 percent, and the Attorney General's DCF results for the Attorney General Proxy Group and Electric Proxy Group are 8.80 percent and 8.95 percent (Exhs. ES-VVR-Rebuttal-3, at 1, 2; AG-JRW-1, at 55). Based on the findings above, the Department will consider these DCF results in our determination of the reasonable range below. In addition, without the adjustment for flotation costs and the leverage adjustment, the Company's updated mean DCF results for the Non-Regulated Proxy Group range from 10.30 percent to 11.70 percent (Exhs. ES-VVR-4, at 1-2; ES-VVR-Rebuttal-4, at 1, 2). Consistent with our findings on the Non-Regulated Proxy Group above, the Department will accord limited weight to the Non-Regulated Proxy Group DCF results in our determination of the reasonable range below.

ii. CAPM

The Department has previously found, and the Company has acknowledged, that the traditional CAPM analysis as a basis for determining a utility's cost of equity has limited value because of several limitations, including some questionable assumptions that underlie the model (Exh. ES-VVR-1, at 52). D.P.U. 20-120, at 423; D.P.U. 19-120, at 383; D.P.U. 17-170, at 298; D.P.U. 10-55, at 514; D.P.U. 08-35, at 207; Commonwealth

Electric Company, D.P.U. 956, at 54 (1982).[189] As a result, it has been the Department's long-standing practice to accord the results of the CAPM limited weight. See, e.g., D.P.U. 17-05-H at 9 & n.9; D.P.U. 20-120, at 423-425; D.P.U. 19-120, at 383-385.

Recently, in an effort to consider a broader range of CAPM analyses in future base distribution rate proceedings, the Department directed all electric and gas companies to submit a CAPM analysis that estimates the market return based on the Value Line 1,700 Stock Universe using Value Line's median of estimated dividend yields and estimated price appreciation potential in addition to the other ROE estimation models that, in the judgment of the party, provide a reliable estimate of the cost of equity. D.P.U. 20-120, at 429-430. As discussed above, NSTAR Electric estimated a market-return based on a one-quarter weighting of a DCF analysis on the S&P 500 Index, a one-quarter weighting of a DCF analysis on the Value Line 1,700 Stock Universe, and a one-half weighting of the historical returns (Exhs. VVR-5, at 1-2; ES-VVR-Rebuttal-5, at 1-2). After review, the Department finds that the Company's proposal complies with the Department's directive and, in this proceeding, incorporating the expected growth based on Value Line's data ensured a more conservative

[189] In D.P.U. 08-35, at 207 n.131, the Department noted the following assumptions of the CAPM: (1) capital markets are perfect with no transaction costs, taxes, or impediments to trading, all assets are perfectly marketable, and no one trader is significant enough to influence price; (2) there are no restrictions to short-selling securities; (3) investors can lend or borrow funds at the risk-free rate; (4) investors have homogeneous expectations (i.e., investors possess similar beliefs on the expected returns and risks of securities); (5) investors construct portfolios on the basis of the expected return and variance of return only, implying that security returns are normally distributed; and (6) investors maximize the expected utility of the terminal value of their investment at the end of one period.

approach in developing the market return and the Company's weighting of the Value Line, S&P 500 Index, and historical data produced a balanced analytical approach to the CAPM (Exhs. ES-VVR-1, at 6; ES-VVR-Rebuttal-1, at 76; ES-VVR-5; ES-VVR-Rebuttal-5).[190] The Department will take these findings into consideration in our determination of the reasonable range below.

The Department previously has rejected attempts to adjust CAPM-derived ROE calculations for company size. D.P.U. 10-70, at 270-271; D.P.U. 08-35. In this proceeding, both the Attorney General and the Company produce several academic studies that support opposite conclusions on whether a size adjustment is warranted (Exhs. ES-VVR-1, at 63; ES-VVR-Rebuttal-1, at 86-88; AG-JRW-1, at 95-98). Further, the Company was unable to indicate whether investors consider the size-adjusted CAPM more reliable than the traditional CAPM, and the size-adjusted CAPM has not been adopted by a significant number of regulatory authorities for purposes of determining an allowed ROE (Exhs. ES-VVR-Rebuttal-1, at 88; DPU 64-2). Overall, the Department finds that the record evidence pertaining to the propriety of a size-adjustment is inconclusive. Therefore, the

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190 The Department notes that there are multiple accepted approaches employed by analysts to estimate the market return, and the Department's findings should not be construed as a determination that the Department will only accept NSTAR Electric's approach in future cases. D.P.U. 20-120, at 424 & n.211 ("Accepted approaches to estimating the market return include using realized market returns during a historical time period; applying the DCF model to a representative market index, such as the S&P 500; and surveying academic and investment professionals."). The Department will continue to evaluate the probative value of parties' CAPM analyses, variations thereof, and other ROE estimation models on a case-by-case basis.

Department will accord the Company's size-adjusted CAPM results limited weight in the determination of the reasonable range below.

The Department previously has rejected the empirical variation of the CAPM, as well. D.P.U. 10-70, at 271. We are not persuaded to deviate from our prior treatment of the empirical CAPM results because NSTAR Electric 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. ES-VVR-1, at 63-66; ES-VVR-Rebuttal-1, at 79-85; AG-JRW-1, at 83-84; DPU 64-2). Therefore, the Department finds that it is appropriate to give limited weight to the Company's empirical CAPM results in our determination of the reasonable range below.

NSTAR Electric's CAPM results include flotation cost adjustments and leverage adjustments. For the same reasons discussed in Section XVI.D.3.b.i above, the Department rejects the Company's flotation cost adjustments and leverage adjustments. To remove the leverage adjustment, the Department applies a beta of 0.89 for the Electric Proxy Group and a beta of 0.86 for the Non-Regulated Proxy Group to the Company's updated CAPM schedules, which do not include the flotation cost adjustments (Exh. ES-VVR-Rebuttal-5).[191] The traditional CAPM results without flotation costs or leverage adjustments are

[191] The Company applies the flotation cost adjustments in its testimony (Exh. ES-VVR-1, at 66).

10.50 percent for the Electric Proxy Group and 10.26 percent for the Non-Regulated Proxy Group (Exh. ES-VVR-Rebutal-5, at 1-4). The size-adjusted CAPM results without flotation costs or leverage adjustments are 10.99 percent for the Electric Proxy Group and 10.04 percent for the Non-Regulated Proxy Group (Exhs. ES-VVR-5, at 1-4; ES-VVR-Rebutal-5, at 1-4). The empirical CAPM results without flotation costs or leverage adjustments are 10.71 percent for the Electric Proxy Group and 10.53 percent for the Non-Regulated Proxy Group (Exhs. ES-VVR-5, at 1-4; ES-VVR-Rebutal-5, at 1-4).

The Attorney General presents a considerably different CAPM result of 7.70 percent (Exh. AG-JRW-1, at 70). The Attorney General places little weight on her CAPM results in her recommended ROE of 8.95 percent, which is 125 basis points higher than her CAPM results and equal to her highest DCF result (Exh. AG-JRW-1, at 33, 95). The Attorney General adopts the position that the results of the CAPM are less reliable because of the difficulty in determining a market risk premium (Exh. AG-JRW-1, at 3; Tr. 14, at 1467). Moreover, the Attorney General has given little to no weight to her CAPM results for many years (Tr. 14, at 1470). Considering the Attorney General's position that her CAPM result is unreliable, the Department places no weight on the results of the Attorney General's CAPM estimate in determining the appropriate ROE.

iii. RPM

The Department has repeatedly found that an equity risk premium analysis 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 bonds yields because these instruments may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, the RMP 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. The Department has found that because the RPM 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 RPM. 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.

Despite the Department's long-standing precedent, and the Company's acknowledgement that "U.S. Treasury securities remain the closest thing to a risk-free asset," the Company relies on projected corporate and public utility bond yields in its RPM (Exhs. ES-VVR-1, at 55, 69-70; ES-VVR-6; ES-VVR-Rebuttal-6). For these reasons, the Department finds that NSTAR Electric's RPM results of 10.66 percent and 11.37 percent are inconsistent with Department precedent and overstate the Company's required ROE (Exhs. ES-VVR-1, at 77; ES-VVR-Rebuttal-1, at 5). Therefore, the Department will not rely on the results of the Company's RPM in our determination of the reasonable range.

c. Authorized ROEs

The Attorney General, Acadia Center, and UMass all argue that the Department should determine NSTAR Electric's ROE based on national and regional allowed ROEs. As an initial matter, the Department reaffirms its finding that the purported upward trend in

ROEs granted in Massachusetts since 2012 is skewed by decisions at the start of that period that set the authorized ROE for those companies at the low-end of the reasonable range to account for deficient management practices (Exh. AG-JRW-1, at 20). D.P.U. 20-120, at 435-436. Moreover, while ROEs granted in other jurisdictions may be indicative of general overall trends, without knowing what quantitative and qualitative factors were considered in these other regulatory agencies, the Department is unable to conclude that these ROEs are appropriate for NSTAR Electric. D.P.U. 19-120, at 363; D.P.U. 17-170, at 282.

In addition, the record demonstrates that the national and regional authorized ROEs relied on by the intervenors come from a small sample of utility companies, and setting an allowed ROE based on averages from prior years would ignore the more recent change in market conditions (Exh. ES-VVR-Rebutal-1, at 18; Tr. 9, at 1004-1006; Tr. 14, at 1437-1443; RR-DPU-40, Att. at 1; RR-ES-1, Att.). Therefore, the Department places no weight on the ROE trends cited by the Attorney General and no weight on the ROEs proposed by Acadia Center and UMass.

d. Reasonable Range

When setting the range of reasonableness and then determining the allowed ROE, the Department is guided by the standard set forth in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944) ("Hope") and Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("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. Hope at 603; Bluefield at 692-693. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692. Both quantitative and qualitative factors must be considered 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 I) at 224-225.

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 a number of 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 to the record evidence and argument with the considerable judgment and agency expertise necessary 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)).[192]

The Department typically accords the most weight to the results of the DCF analysis in determining the reasonable range. D.P.U. 20-120, at 396; D.P.U. 17-05-H at 13. Based on our precedent and findings above, the Department finds that it is appropriate in this case to give the most weight to the mean DCF results for the Electric Proxy Group and the Attorney General Proxy Group, with a range of results from 8.50 percent to 9.20 percent (Exhs. ES-VVR-3, at 1, 2; ES-VVR-Rebuttal-3, at 1, 2; AG-JRW-1, at 55). Additionally, the Department finds that it is appropriate in this case to give more than limited weight to the Company's traditional CAPM results for the Electric Proxy Group of 10.50 percent because of the impact of changing interest rates on the DCF analysis, but not as much weight as the DCF because of the questionable assumptions underlying the CAPM. Further, based on the

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192 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.

findings above with respect to the Non-Regulated Proxy Group and the CAPM variants, the Department finds it appropriate to give limited weight to the DCF results of the Non-Regulated Proxy Group, the size-adjusted CAPM and empirical CAPM results of the Electric Proxy Group, and the CAPM results of the Non-Regulated Group. Finally, because the Company's RPM results overstate the cost of equity and the Attorney General does not find her CAPM result to be reliable, the Department does not rely on those model results to determine the reasonable range. 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 9.40 percent to 10.00 percent, with a midpoint of 9.70 percent, is a reasonable range of ROEs for NSTAR Electric in this proceeding.

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.

During this proceeding, the Federal Reserve Board indicated that it would shift to a more aggressive monetary policy to address the highest inflation rate seen in the past 40 years (Exh. ES-VRR-Rebuttal-1, at 21). In May 2022, the Federal Reserve Board raised the Federal Funds target rate, indicated that it would institute further rate increases at subsequent meetings through the year, and stated that it would begin to reduce the size of its securities portfolio (Exh. ES-VRR-Rebuttal-1, at 29). From the end of 2021 to June 2022, the 30-year U.S. Treasury bond yield increased over 100 basis points, A-rated long-term utility bond yields increased by 150 basis points, and economists expect longer-term interest rates will continue to trend higher while the Company's rates are in effect (Exh. VVR-Rebuttal-1, at 23, 27-28; RR-DPU-40; RR-ES-1).

Based on the evidence, NSTAR Electric contends that the Department's decision must account for the recent increases in interest rates and inflation because as interest rates increase the cost of equity also increases (Company Reply Brief at 26, citing Tr. 14, at 1433, 1436-1439, 1441-1443; RR-DPU-40, Att. at 1; RR-ES-1). After review, the Department concludes that, although there is not a one-to-one correlation between an increase in long-term debt interest rates and the cost of equity, NSTAR Electric's argument that current market conditions will increase the cost of equity while the Company's rates are in effect is more persuasive than the Attorney General's argument that an adjustment is not warranted. Therefore, the Department will set the Company's allowed ROE in the upper half of the reasonable range to account for market conditions.

f. 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 I) 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 be appropriate under the circumstances"); Boston Gas Company v. Department of Public Utilities, 359 Mass. 292, 305 (1971) (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[193] 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 transactions and selection of rate

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193 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 Public Service Corp. v. Citizens' Utilities Board, 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 Communications, Inc. v. Washington Utilities & Transportation Commission, 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. Utilities Commission v. General Telephone 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).

case consultants warranted ROE at lower end of reasonable range). With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14. 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 Department has reviewed the record evidence and finds that the Company has met or exceeded its service quality standards and benchmarks (Exh. ES-CAH-DPH-1, at 111). The Company has also demonstrated strong performance with respect to reliability and storm restoration (Exh. ES-CAH-DPH-1, at 112-114). The Department, however, also notes that the Company scaled back its manhole inspections in recent years and has experienced an uptick in manhole disturbance events since its last rate case, particularly in 2018, 2019, and 2022 (Tr. 12, at 1303; RR-DPU-45). In response to these events, the Company has undertaken steps to address manhole disturbances, including expanding its replacement of manhole covers with energy release cover (Tr. 12, at 1303-1309; RR-DPU-46). The Department finds, while NSTAR Electric should continue to take proactive steps to maintain an adequate level of manhole safety inspections and continue to install new monitoring and safety technologies, the Company's handling of manhole safety does not constitute a systemic service quality shortcoming. The Department also notes the absence of any evidence of systemic service quality shortcomings that warrant a downward adjustment to NSTAR Electric's allowed ROE. Based on the record and balancing the Company's service quality record, the Department concludes that NSTAR Electric's qualitative factors justify an allowed ROE above the midpoint of the reasonable range.

g. Investment Risk

The Attorney General states, and the Department has held, that credit ratings provide investors with relevant information with respect to a company's risk level (Exh. AG-JRW-1, at 6, 24). D.P.U. 20-120, at 396. Nonetheless, debt and equity securities are exposed to different risks and, therefore, require different returns. D.P.U. 20-120, at 396. Therefore, while credit ratings alone do not reflect the full range of risk borne by equity investors, it would be reasonable for investors to consider a company's credit rating in the assessment of investment risk. D.P.U. 20-120, at 396. NSTAR Electric has not provided any persuasive evidence that investors would not rely on credit ratings in the assessment of investment risk, and we reaffirm our previous findings.

The Attorney General also contends that NSTAR Electric has lower investment risk because the Company's equity ratio is higher than the average equity ratios of the proxy groups (Exh. AG-JRW-1, at 30). Credit rating agencies take a company's capital structure into account in their ratings (see e.g., Exh. AG-1-11, Att. (a) at 18, Att. (d) at 7 (Supp.) (liquidity analysis includes company's management of its capital structure)). Therefore, the Department concludes that separate adjustments to the allowed ROE for NSTAR Electric's credit rating and NSTAR Electric's capital structure would overstate the impact of the Company's capital structure on its investment risk.

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. 20-120, at 431-432; D.P.U. 19-120, at 405-405; D.P.U. 18-150, at 494-495; D.P.U. 17-05, at 710-711. The Department has established in this Order a PBR plan specific to the Company. As described Section IV.D.5 above, the PBR plan allows NSTAR Electric to implement annual rate adjustments to provide revenue support for post-test-year expense increases and capital investments and includes an exogenous cost provision. The Department, however, also has approved a five-year stay-out provision (see Section IV.D.5.a. above).

Above, the Department found that NSTAR Electric's ROE should be in the upper half of the reasonable range because of extraordinary market conditions and the Company's qualitative factors. Based on a balancing of the provisions of the PBR plan approved in this Order and NSTAR Electric's credit rating relative to the proxy groups, the Department finds that NSTAR Electric's allowed ROE should be at the lower-end of the upper half of the reasonable range.

4. 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 9.80 percent is within a reasonable range of rates that will preserve NSTAR Electric's financial integrity, will 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.[194] 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.

XVII. 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 structure are to achieve efficiency and simplicity as well as to ensure continuity of rates, equity and fairness between rate classes, and corporate earnings stability. D.P.U. 19-120, at 409; D.P.U. 17-170, at 313; G.L. c. 25, § 1A.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and 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

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[194] 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 Fitchburg Gas and Electric Light Company et al. v. Department of Public Utilities, 467 Mass. 768 (2014).

in rate structure means it is cost based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 19-120, at 409; D.P.U. 17-170, at 313-314.

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 time to adjust their consumption patterns in response to a change in rate structure. In setting rates, the Department balances fairness and equity. Fairness means that each customer class 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.[195] Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 19-120, at 409-410; D.P.U. 17-170, at 314; G.L. c. 25, § 1A.

There are two parts to determining rate structure: cost allocation and rate design. The cost allocation step assigns a portion of a company's total costs to each rate class through an embedded ACOSS. The allocated cost of service represents the cost of serving each rate class at equalized rates of return ("EROR") given the company's level of total costs. D.P.U. 19-120, at 410; D.P.U. 17-170, at 314.

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[195] The Department addresses the low-income discount rate and compliance with G.L. c. 164, § 141 in Section XVII.C.3 below.

There are four steps to develop an ACOSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing 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 in order to determine the total costs of serving each rate class at EROR. D.P.U. 19-120, at 410; D.P.U. 17-170, at 315.

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 to equalize the rates of return and 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. 19-120, at 411; D.P.U. 17-170, at 315.

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 goal of equity, the Department also has ordered the establishment of special rate classes for certain low-income customers and has considered the effect of such rates and rate changes on low-income customers.[196] D.P.U. 19-120, at 411; D.P.U. 17-170, at 316; G.L. c. 25, § 1A. 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) (discounted low-income rates). In addition, G.L. c. 164, § 94I ("Section 94I") requires the Department, in each base distribution rate proceeding, to design rates based on EROR by customer class as long as the resulting impact for any one customer class is not more than ten percent.[197] The

196 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.

197 Section 94I provides:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment 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 [D]epartment 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 [D]epartment.

Department reaffirms its rate structure goals that are designed to result in rates that are fair, equitable, 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.

The second part of determining the rate structure is rate design. The level of the revenues 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 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. 19-120, at 412; D.P.U. 17-170, at 317.

B. Allocated Cost of Service Study and Rate Design

1. Introduction

NSTAR Electric currently consists of four legacy operating companies. They are Boston Edison Company ("Boston Edison"), Cambridge Electric Light Company ("Cambridge Electric Light"), Commonwealth Electric Company ("Commonwealth Electric") and WMECo (Exh. ES-RDC-1, at 2). In its previous base distribution rate case filing, D.P.U. 17-05, the Company filed a proposal to consolidate and align the rates and rate classes associated with its Boston Edison, Cambridge Electric Light, Commonwealth Electric, and WMECo operating companies into two sets of rates; Boston Edison, Cambridge Electric Light, and Commonwealth Electric rates comprised the EMA rate classes, and the WMECo rates comprised the WMA rate classes (Exh. ES-RDC-1, at 2-3). The proposal envisioned the consolidation of existing customers under a single set of tariffs for EMA and WMA territories, with separate distribution pricing for customers in EMA and in WMA, but consolidated transmission rates and certain reconciling rates (Exh. ES-RDC-1, at 3). The Department allowed certain components of NSTAR Electric's previous rate consolidation and alignment plan, but we did not accept the Company's entire plan and directed the Company to undertake a gradual implementation of a consolidated and aligned rate design for general service customers to ameliorate large bill impacts without a multi-year subsidy plan, to improve unclear tariffs, and to comply with Section 94I (Exh. ES-RDC-1, at 4). D.P.U. 17-05, at 96. Moreover, the Department encouraged the Company to provide for a more gradual plan for consolidation and alignment either through its next general rate filing or through a revenue neutral rate design filing(s) (Exh. ES-RDC-1, at 4). D.P.U. 17-05-B at 96.

In the current filing, the Company proposes to streamline and align its rate offerings for possible future consolidation or simplification (Exh. ES-RDC-1, at 5). The Company's proposal addresses the ACOSS, rate consolidation, distribution rate design, transmission rate allocation and design, reconciliation rate allocation factors, and revised LED streetlight pricing. Each of these areas is addressed below.

2. ACOSS

a. Company Proposal and Updates

NSTAR Electric performed an ACOSS that assigns or apportions, based on cost-causation principles, the Company's total cost of service to each rate class (Exh. ES-ACOS-1, at 5). NSTAR Electric developed its ACOSS using five main steps (Exh. ES-ACOS-1, at 6-7). First, the Company functionalized its rate base and costs into the main functions required to provide electricity to customers (Exh. ES-ACOS-1, at 7). NSTAR Electric followed the functional categories contained in the FERC Uniform System of Accounts ("USOA-FERC"),[198] which are production, transmission, distribution, customer services, and administrative and general (Exh. ES-ACOS-1, at 7).

Second, the Company performed a levelization of costs, which involves the disaggregation of costs by customers' voltage service levels, or voltage "splits" (Exh. ES-ACOS-1, at 7). The service level designations are a means of identifying and associating investment and expenses with customers and their loads at established points of service (Exh. ES-ACOS-1, at 7). The levelization is performed because typically, the lower the voltage level of service required by the customer, the greater the cost to provide service (Exh. ES-ACOS-1, at 7). The Company applied voltage splits using an analysis developed for the marginal cost study submitted in the Company's last base distribution rate case, D.P.U. 17-05 (Tr. 8, at 789). The marginal cost study was prepared in 2015 and encompassed year-by-year plant additions by FERC account for the 30-year period of 1986 through 2015 (Exh. CLC-ES 3-6, Att. (h) (Supp. 2)).

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[198] 18 CFR Part 1.

Third, the Company classified the functionalized and levelized costs into three primary "cost-causative" characteristics of investment and expenses (Exh. ES-ACOS-1, at 8). Each type of cost varies in response to changes in one or more of three categories: energy consumed (kWh), peak demand (kilowatt ("kW")), and number of customers (Exh. ES-ACOS-1, at 8).

Next, once the costs are classified, they were assigned to the group or groups of customers responsible for those costs (Exh. ES-ACOS-1, at 8). Finally, in the fifth step, the Company developed allocators to allocate common costs (costs that cannot be assigned to specific customers) among the rate groups (Exh. ES-ACOS-1, at 8).

The Company used 24 rate classes in the ACOSS study (Exh. ES-ACOS-1, at 8). The rate classes were mostly denominated as Residential and General Service, with differentiation of the former group by whether the customer has electric space heating, and of the latter group by legacy service area and by size, as defined by billing demand (Exh. ES-ACOS-1, at 8). Additional rate classes included two sets of streetlight customers, differentiated by equipment ownership (i.e., Company or customer) (Exh. ES-ACOS-1, at 8).

As discussed in further detail below, the Company proposed to consolidate some rate classes within its legacy service areas and to create improved alignment of rate class definitions across the service areas (Exh. ES-ACOS-1, at 9). The Company states that in implementing the consolidation and alignment, the ACOSS faced the challenge that the rate classes defined for the study are prospective, using rate class definitions submitted for approval in this filing (Exh. ES-ACOS-1, at 9). Several of the definitions differ from their predecessors, so the Company estimated customer numbers, peak demand, and energy consumption for the newly defined classes based upon numbers for the current classes (Exh. ES-ACOS-1, at 9).

On May 13, 2022, the Company filed its first revised ACOSS and rate design exhibits (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 1); ES-RDC-2 through ES-RDC-5 (Rev. 1); ES-RDC-7 (Rev. 1)). In these revised exhibits, the Company: (1) updated test-year billing determinants from 2020 to 2021 quantities; (2) updated the test-year revenue requirement to reflect the Company's revisions in its April 22, 2022 filing; (3) restricted revenue allocations to residential customers per the Department's directive in D.P.U. 20-120, at 485, and as discussed in the Company's prefiled testimony; and (4) revised the low-income discount from 36 percent to 42 percent (Exhs. ES-RDC-1, at 36-39; ES-ACOS-2 through ES-ACOS-5 (Rev. 1); ES-RDC-2 through ES-RDC-5 (Rev. 1); ES-RDC-7 (Rev. 1); LI-ES 1-4; LI-ES 1-5).

On July 1, 2022, the Company filed a second revised ACOSS and rate design exhibits to reflect another revenue requirement update filed earlier on June 24, 2022 (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 2); ES-RDC-2 through ES-RDC-5 (Rev. 2); ES-RDC-7 (Rev. 2)). In these revised exhibits, the Company: (1) corrected customer counts related to the existing WMA Rate T-4, and proposed WMA Rates G-1 and T-4; (2) updated primary and secondary voltage splits; and (3) updated the weighting favors for customer assistance and sales (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 2); ES-RDC-2 through ES-RDC-5 (Rev. 2); ES-RDC-7 (Rev. 2); CLC-ES 3-6 Att. (h) (Supp. 3)). Regarding the voltage splits, the Company applied a new method to determine voltage level line items based on more recently calculated 2020 values and provided an explanation of how the primary voltage level line items were determined (Exh. CLC-ES 3-6, Att. (h) (Supp. 3); Tr. 8, at 788-792). As noted above, in its initial ACOSS, the Company applied values used in its previous rate filing, D.P.U. 17-05 (Exh. CLC-ES 3-6, Att. (h) (Supp. 2); Tr. 8, at 789).

On July 22, 2022, in response to a record request issued at the evidentiary hearings by Cape Light Compact, the Company updated its second revised ACOSS (RR-CLC-3). In this response, the Company provided (i) an explanation and supporting documentation for the classification criteria used in the engineering assessment to classify retirement units for each plant account listed in Exhibit CLC-ES-3-6 Att. (h) (Supp. 3), which had been filed on July 12, 2022, and (ii) an update to voltage split information used in second revised ACOSS filed on July 1, 2022. As part of its response to Record Request CLC-3, the Company updated its second revised ACOSS, reflecting values from Exhibit CLC-ES-3-6 Att. (h) (Supp. 3), and inclusive of corrections to errors identified while responding to Record Request CLC-4 through Record Request CLC-6 (RR-CLC-3, Att. (d)).

On September 27, 2022, the Company filed a third revised ACOSS and rate design exhibits to reflect another revenue requirement update, which was filed on the same day (Exhs. ES-ACOS-2 through ES-ACOS-5 (Rev. 3); ES-RDC-2 through ES-RDC-5

(Rev. 3)).[199] Additionally, in this version of the ACOSS, the Company incorporated all of the changes it identified in responding to Record Request CLC-3 as discussed above (i.e., provided documentation and explanation for the classification criteria used in the engineering assessment to classify retirement units for each plant account, further updated voltage splits as provided in its second revised ACOSS filed on July 1, 2022, and corrected errors identified while responding to other record requests) (RR-CLC-3, Att. (d); RR-CLC-4; RR-CLC-5; RR-CLC-6; see Exh. CLC-ES 3-6, Att. (h) (Supp. 3)).

b. Positions of the Parties

i. Attorney General

The Attorney General challenges certain methods employed by the Company regarding cost allocation. Specifically, the Attorney General argues that the change of allocations between the first revised and second revised ACOSSs and between the second revised ACOSS and the Company's response to Record Request CLC-3, are significant and provided limited opportunity for Department and intervenor review (Attorney General Brief at 157-158). The Attorney General also asserts that NSTAR Electric's data is deficient, and that the Company does not have a complete understanding of the basis for the updated voltage allocations being applied in the most recent versions of the ACOSS (Attorney General Brief at 155, 158).

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199 The final revenue requirement shown in Exhibit ES-REVREQ-2 is slightly lower than the revenue requirement used to develop the rate design exhibits due to the timing of the debt issuance reflected in the cost of service.

The Attorney General asserts that the Department should require NSTAR Electric to use the original filed voltage splits reflective of the values used in its last base distribution rate case (Attorney General Brief at 158). The Attorney General also asserts that the Department should require that the Company include a comprehensive and thorough distribution plant voltage analysis as part of its initial filing in its next base distribution rate case (Attorney General Brief at 158-159).

ii. Cape Light Compact

Cape Light Compact supports the Company's corrections in its second revised ACOSS filing as well as the ACOSS filed as the Company's response to Record Request CLC-3, Att. (d) (CLC Brief at 18). Cape Light Compact also agrees with the updates made to reflect corrected primary and secondary share assignments as well as the change in method used by the Company to classify primary and secondary voltage splits using 2020 data (CLC Brief at 19, 21; CLC Reply Brief at 5). In addition, Cape Light Compact agrees with the changes to weighting factors updated for customer assistance and sales in the Company's second revised ACOSS (CLC Brief at 22).

Cape Light Compact, however, disagrees with the Company's use of amalgamation of primary shares for accounts 364 and 365, and for accounts 366 and 367 (CLC Brief at 23; CLC Reply Brief at 9-10). Cape Light Compact argues that the Company's use of amalgamation to assign weights to primary and secondary customers for these accounts should be rejected because it results in arbitrary cost allocation and unjustified cost shifts among rate classes (CLC Brief at 23; CLC Reply Brief at 9-10). Cape Light Compact also contends that amalgamated shares do not result in accurate cost allocation, are entirely unnecessary to avoid volatility between rate cases, and result in unjustified cost shifts between rate classes (CLC Brief at 23, 26-27). Cape Light Compact asserts that the Department should reject the Company's amalgamated shares for accounts 364 and 365, and for accounts 366 and 367, and recommends that the Department direct the Company to produce an updated ACOSS model to reflect this change (CLC Brief at 27-28).

iii. Company

NSTAR Electric rejects the notion that the data used to develop the voltage splits is deficient, and the Company contends that the categorization of its assets begins with the WAM System where individual work orders are created (Company Brief at 423). NSTAR Electric asserts that completed work orders that have met all work-management requirements are then classified based on a combination of guidance from the Company's Capital vs. Expense Policy ("APS#8"), the USOA-FERC, and the Company's retirement unit manual (Company Brief at 423, citing RR-CLC-3, Atts. (a) & (b); RR-CLC-4, Att. 4(c)). NSTAR Electric also claims that APS#8 lays out guidelines as to when assets may be capitalized, and the USOA-FERC and Company's retirement unit manual illustrate the types of assets that are capitalized in each plant account (Company Brief at 423, citing RR-CLC-3). According to NSTAR Electric, however, voltage information is not available in these plant records so Company engineers must use their knowledge and expertise to review the listed retirement units in each account in assessing their application for primary versus secondary service (Company Brief at 423, citing RR-CLC-3). Finally, the Company asserts that in its review of assets in accounts 365-368 it found erroneous assignments, and that it corrected these errors in the ACOSS model filed in response to Record Request CLC-3 (Company Brief at 424, citing RR-CLC-3 through RR-CLC-6).

NSTAR Electric also affirms its decision to use updated voltage allocations of distribution plan assets booked to FERC Accounts 366 and 367 in its second and third revised ACOSS (Company Brief at 422-423). The Company argues that its late-stage voltage split allocation update was appropriate, as it was first filed in response to a record request issued by Cape Light Compact and was based on the test year rather than extending the time series analysis or continuing using the historical method to allocate voltage splits as approved in D.P.U. 17-05 (Company Brief at 423, citing RR-CLC-2; RR-CLC-3).

Further, NSTAR Electric argues that its use of amalgamation of primary shares is consistent with Department precedent, in particular the Company's previous ACOSS approved in D.P.U. 17-05 (Company Brief at 418, 422; Company Reply Brief at 56-57). The Company also contends that using amalgamated shares is supported by the National Association of Regulatory Utility Commissioners ("NARUC") Cost of Service manual, particularly for Accounts 366 and 367 (Company Brief at 418, 422, citing NARUC manual at 91). Further, the Company asserts that Account 365 represents overhead conductors and devices that must be attached to the poles and towers recorded in Account 364, and therefore the primary voltage shares for those two accounts are set equal (Company Brief at 422, citing D.P.U. 17-05). In addition, the Company argues that it would be inappropriate to classify all poles as primary because poles that carry both primary and secondary lines are often classified as primary, while poles that carry secondary lines are classified as secondary (Company Brief at 422, citing D.P.U. 17-05). Therefore, NSTAR Electric concludes that changing the Company's accounting and separating the calculations for Accounts 364 and 365 would be inconsistent with Department precedent (Company Brief at 422, citing D.P.U. 17-05).

c. Analysis and Findings

First, the Department addresses the Company's updated ACOSS filings. The Company explained during evidentiary hearings the significance of accurately classifying assets to the correct account and between primary service and secondary service customers:

> The primary and secondary splits occur for the distribution asset accounts, or rate-base accounts, typically 364 to 368 under the FERC accounting system. And the purpose of the splits is to ensure that costs are allocated to customer groups that actually make use of the assets. So, one would want a primary-level customer not to be responsible for secondary-level costs. So, for each of these main distribution accounts, 364 to 368, the effort is made in typical rate cases and in this one to determine the share of assets that serves primary only and the share of assets that serves secondary or primary and secondary.
> (Tr. 8, at 783).

The Company, therefore, acknowledges that it is charged with tracking costs to each distinct account, and accurately splitting the shares of those costs between primary service and secondary service customers.

For concerns related to continuity and fairness, the Company should have a clear process by which it assigns and allocates costs across accounts and customers. The Department and intervenors need the opportunity in a base distribution rate case to examine the procedures and data behind the calculations. In the instant case, however, the Company, without explanation or support, filed, concurrent with its submission, new allocations and voltage splits in its second ACOSS, response to Record Request CLC-3, and third revised ACOSS, after the discovery period for this case closed. While the Company states that the values used in its revised ACOSSs are based on data that was not previously available (Tr. 8, at 790), the Department cannot find that such data has been adequately reviewed for consistency and accuracy. Absent clear, replicable processes or procedures documented to explain how the Company approaches the assignment and allocation of costs to primary service and secondary service customers for these accounts, the Department directs the Company to utilize the costs and voltage splits used in its initial filing (i.e., the data used in D.P.U. 17-05) in its current cost allocation process. In addition, the Department directs NSTAR Electric to undertake a review of the processes used to assign costs to individual accounts and primary service and secondary service customers and to report on the results of the review in the Company's initial filing in its next base distribution rate case.

Cape Light Compact expresses concerns with the Company's use of amalgamation for Accounts 364 and 365, as well as for Accounts 366 and 367, when assigning the revenue requirement associated with those accounts to primary service and secondary service customer rate classes (CLC Brief at 23; CLC Reply Brief at 9-10). Cape Light Compact argues that the Company's use of amalgamation to assign weights to primary and secondary customers for these accounts should be rejected because it results in arbitrary cost allocation and unjustified cost shifts among rate classes (CLC Brief at 23; CLC Reply Brief at 9-10). The Company does not claim that it is incapable of producing costs by account, or incapable of properly assigning them by voltage split; it simply contends that such practice was used in the prior rate filing, D.P.U. 17-05, and that share combinations are supported by the NARUC Cost of Service manual (Company Brief at 418, 422). Absent a lack of data, information, or other rationale pertaining to the actual data available, the Department is not persuaded that the continued amalgamation of Accounts 364 and 365, as well as Accounts 366 and 367, is necessary. The Company has distinct cost data for these accounts, which, by definition, will lead to more accurate cost allocation as it will accurately apply the principle of cost causation (Tr. 8, at 793). Further, we find that the Company has not provided analysis or sufficient information to convince us that amalgamation of voltage splits is necessary to avoid rate volatility (Exh. CLC-ES 3-6, Att. (h) (Supp. 2)). Additionally, our prior approval of amalgamating certain costs does not preclude us from reaching a different finding here, particularly where amalgamation was not raised as a contested issue in D.P.U. 17-05 and, as we do here, we explain the reason for our decision. United Automobile Workers v. National Labor Relations Board, 802 F.2d 969, 974 (1986); D.P.U. 20-120, at 325 n.158. Therefore, the Department directs the Company not to use amalgamation of accounts for which distinct detail exists and to file a revised ACOSS in compliance with this directive.

3. Rate Consolidation and Revenue Allocation

a. Introduction

The Company proposes to eliminate obsolete rate offerings, partially consolidate and align tariffs, and simplify existing rate designs (Exh. ES-RDC-1, at 5). In addition, the

Company proposes to refine certain tariff definitions, introduce a non-demand small C&I offering within Rate G-1, and eliminate or alter seasonal and time-of-use ("TOU") rates (Exh. ES-RDC-1, at 5).

The current rate groupings for C&I customers, which are born from legacy classifications, are classified differently, and assigned significantly different rate designs, which the Company states makes it difficult to consolidate rate classes without triggering unacceptable bill impacts (Exh. ES-RDC-1, at 17). For example, Cambridge Electric Light Rate G-2 includes customers with monthly demands greater than 100 kW, and these customers are categorized as medium/large general service customers; however, in WMA, customers with monthly demands up to 349 kW are categorized as small general service customers (Exh. ES-RDC-1, at 17). As the Company pursues consolidation among its legacy rate classes, the categorization of various classes is significant to ensure that customers are treated equitably across the Company's entire operating territory (Exh. ES-RDC-1, at 17).

NSTAR Electric states that it is not proposing entirely new rate classes, rather it is proposing new names and alternative definitions for some rate classes (Exh. ES-RDC-1, at 21). To establish consistency and simplicity, the Company proposes to establish: (1) Rate G-1 as its rate class for customers with demand annually equal to or less than 100 kW; (2) Rate G-2 for customers with demand annually greater than 100 kW; (3) Rate G-3 for customers with large loads who frequently receive service at the primary voltage level; and (4) WMA Rate T-5, which is unique to WMA and which serves a small number of customers (Exh. ES-RDC-1, at 21).

For small C&I customers, the Company proposes to introduce a common threshold throughout its service territory (Exh. ES-RDC-1, at 19). Currently, the demand threshold for Boston Edison Rate G-1 is 10 kW, Cambridge Electric Light Rate G-1 and Commonwealth Electric Rate G-1 is 100 kW, and WMA Rate G-0 is 349 kW (Exh. ES-RDC-1, at 19). The Company states that the most efficient and least disruptive way to establish consistency among customers is to adopt one of the existing demand thresholds (Exh. ES-RDC-1, at 19). Therefore, the Company chose a 100-kW demand threshold for small C&I customers (Exh. ES-RDC-1, at 19).[200]

The Company also proposes to introduce a new non-demand offering for small C&I customers under the proposed G-1 rate class (Exh. ES-RDC-1, at 5, 41). NSTAR Electric states that the non-demand offering and the Company's general attention toward energy-only rates for small C&I customers are in response to the evolving nature of rate design considering public policy, technology, and ever-shifting customer uses, such as electric vehicle charging (Exh. ES-RDC-1, at 42).

Further, the Company proposes to eliminate seasonal pricing in the Boston Edison service area, except for customers taking service under Rate T-1, because such pricing potentially results in higher bills in the summer through a combination of higher rates and

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[200] The Company also proposes to allow customers to take service on Rate G-2 if their average monthly demand over 12 consecutive months – rather than their monthly demand – exceeds 100 kW (RR-TEC-1).

usage (Exh. ES-RDC-1, at 41-42). The Company states that elimination of the summer price differential will provide some rate relief to customers (Exh. ES-RDC-1, at 41-42).

The Company also proposes that rate classes and customers falling into the medium general service category that build on the definitions established for small general service rate classes and the existing definitions for large general service rate classes (Exh. ES-RDC-1, at 19-20). As such, customers using more than 100 kW annually that are not otherwise assigned to a large general service rate class are considered medium general service customers (Exh. ES-RDC-1, at 20). The Company states that it is not proposing revisions to rate class definitions in the large general service category at this time, as the legacy class differences are not as significant as those seen in the small general service group (Exh. ES-RDC-1, at 20).

More specifically, the Company proposes: (1) expanding the Boston Edison Rate G-1 offering from 10 kW to 100 kW; (2) moving the current Boston Edison Rate G-2 customers to either the expanded Boston Edison Rate G-1or Boston Edison Rate T-2; (3) renaming the Boston Edison Rate T-2 as Boston Edison Rate G-2 and changing the availability from greater than ten kW to greater than 100 kW; (4) combining Cambridge Electric Light Rates G-0, G-1, and G-4 into Cambridge Electric Light Rate G-1 that encompasses customers with monthly demand up to 100 kW, and cancel Cambridge Electric Light Rates G-0 and G-4; (5) consolidating Commonwealth Electric Rate G-5 customers into new Commonwealth Electric Rate G-1; (6) closing Commonwealth Electric Rate G-7; (7) consolidating WMA Rate G-0, WMA Rate T-0, WMA Rate G-2, and WMA Rate T-4 with monthly demand up to 100 kW into a new WMA Rate G-1; (8) moving the remaining WMA Rate G-0, WMA Rate T-0, and WMA Rate G-2 customers with demand greater than 100 kW to revised WMA Rate G-2 with monthly demand greater than 100 kW and up to 349 kW, thereby eliminating WMA Rate T-0; (9) limiting WMA Rate T-4 to monthly demand greater than 100 kW and up to 349 kW; and (10) renaming WMA Rate T-2 as WMA Rate G-3 (Exh. ES-RDC-1, at 20, 71-72).

The Company also proposes to eliminate use of the declining block rate/demand charge design and, where appropriate, that the rate design would be replaced by a simple customer charge/energy charge design with no demand charge or demand ratchets (Exh. ES-RDC-1, at 8-9). The Company states that elimination of the current energy block design will improve the price signal to ratepayers of the cost of energy at the margin (Exh. ES-RDC-1, at 42). In addition, the Company proposes to maintain block demand charges, or demand ratchets only on those rates where there are continuity concerns (Exh. ES-RDC-1, at 10-11).

The Company states that currently effective optional TOU rate offerings have been closed for new customer enrollment, with the exception for Cambridge Electric Light Rate G-4, Commonwealth Electric Rate G-7, WMA Rate T-0, and WMA Rate T-4 (Exh. ES-RDC-1, at 11). The Company proposes to transfer Cambridge Electric Light Rate G-4 customers to the proposed Cambridge Electric Light Rate G-1, close Commonwealth Electric Rate G-7, and consolidate WMA Rate T-0 customers into proposed

WMA Rate G-1 (Exh. ES-RDC-1, at 11). In addition, the Company proposes to redefine WMA Rate T-4 (Exh. ES-RDC-1, at 11).

Finally, the Company states that it is not introducing new TOU energy rates at this time, as it asserts that volumetric TOU rates are not appropriate as distribution system costs are primary demand related (Exh. ES-RDC-1, at 11). The Company notes that the current optional TOU rate offerings are vestiges of electric deregulation and that that new TOU rate design would be addressed following the deployment of AMI (Exh. ES-RDC-1, at 11-12, citing Investigation into Time Varying Rates, D.P.U. 14-04-C at 2 (2014); Rulemaking Pursuant to Executive Order 562 to Reduce Unnecessary Regulatory Burden, D.P.U. 15-183 (2016); D.P.U. 1720.

The table below summarizes the Company's current and proposed rate classes and categories:

Rate Group	**Rate Class – current**	**Rate Class - proposed**
Residential (no changes)	Rates R-1, R-2, R-3, and R-4	Rates R-1, R-2, R-3, and R-4
Small General Service	Boston Edison: Rate G-1 (< =10 kW) Rate T-1 (< =10 kW TOU) Rate G-2 (> 10 kW) Cambridge Electric Light: Rate G-0 (< =10 kW) Rate G-6 (< =10 kW TOU) Rate G-1 (10< kW< =100) Rate G-4 (10< kW< =100 TOU) Rate G-5 (Comm. Space Heat) Commonwealth Electric: Rate G-1 (< =100 kW) Rate G-7 (< =100 kW TOU)	Boston Edison: Rate G-1 (< =100 kW) Rate T-1 (< =10 kW TOU) Cambridge Electric Light: Rate G-1 (< =100 kW) Rate G-6 (< =10 kW TOU) Rate G-5 (Comm. Space Heat) Commonwealth Electric: Rate G-1 (< =100 kW) Rate G-7 (< =100 kW TOU) Rate G-4 (General Power)

	Rate G-4 (General Power) Rate G-5 (Comm. Space Heat) Rate G-6 (All-Electric School) WMA: Rate 23 (Water Heating) Rate 24 (Church) Rate G-0 (<= 349 kW) Rate T-0 (<= 349 kW TOU)	Rate G-6 (All-Electric School) WMA: Rate 23 (Water Heating) Rate 24 (Church) Rate G-1 (<= 100 kW)
Medium General Service	Boston Edison: Rate T-2 (> 10 kW) Cambridge Electric Light: Rate G-2 (> 100 kW) Commonwealth Electric: Rate G-2 (100< kW <=500) WMA: Rate G-2 (<=349 kW; Primary) Rate T-4 (<=349 kW; Primary TOU)	Boston Edison: Rate G-2 (>100 kW) Cambridge Electric Light: Rate G-2 (> 100 kW) Commonwealth Electric: Rate G-2 (100< kW <=500) WMA: Rate G-2 (<=349 kW; Primary) Rate T-4 (<=349 kW; Primary TOU)
Large General Service (no changes)	Boston Edison: Rate G-3 (14 kV) Rate WR (MWRA) Cambridge Electric Light: Rate G-3 (>100 kW; 13.8 kV) Rate SB1/MS1/SS1 (MIT Standby) Commonwealth Electric: Rate G-3 (>500 kW) WMA: Rate T-2 (349< kW <= 2500) Rate T-5 (> 2500 kW)	Boston Edison: Rate G-3 (14 kV) Rate WR (MWRA) Cambridge Electric Light: Rate G-3 (>100 kW; 13.8 kV) Rate SB1/MS1/SS1 (MIT Standby) Commonwealth Electric: Rate G-3 (>500 kW) WMA: Rate G-3 (349< kW <= 2500) Rate T-5 (> 2500 kW)
Streetlights (no changes)	Rates S-1, S-2	Rates S-1, S-2

Exh. ES-RDC-1, at 18-19.

a. <u>Positions of the Parties</u>

i. <u>Attorney General</u>

The Attorney General argues that the Department should reject the Company's proposed elimination of seasonal and TOU rates and establish more efficient TOU windows without delay (Attorney General Brief at 171-173). The Attorney General asserts that the Company has not presented a viable reason to eliminate or reduce the availability of seasonal or TOU rates, and she contends that the implementation of new TOU rates could take several years to complete (Attorney General Brief at 173). In addition, the Attorney General claims that the Company's proposal to eliminate seasonal and TOU rates is inconsistent with Department policies favoring peak-demand reduction and optimizing benefits associated with alternative rates such as TOU rates (Attorney General Brief at 173, citing D.P.U. 14-04-C at 3). The Attorney General asserts that to maximize benefits associated with existing TOU rates, the Department should establish a more limited on-peak window and pricing ratios (Attorney General Brief at 175, citing Exh. AG-DED-Surrebuttal-1, at 12-17).

ii. DOER

DOES argues that the Company's peak periods for commercial TOU rates send the wrong incentives to commercial customers, conflict with the structure of the "Clean Peak" program and may result in increased curtailments of renewable generation (DOER Reply Brief at 7-8). Further, DOER contends that, while a future proceeding to establish AMI-supported time-varying rates is necessary and will produce new rates, future process is not a reason to avoid modifications to improve existing TOU rates in the current proceeding (DOER Reply Brief at 8).

iii. Acadia Center

Acadia Center argues that the Department should reject the Company's proposed elimination of seasonal and TOU rates and establish more efficient TOU windows, such as revising on-peak hours to include the hours between 3:00 p.m. and 7:00 p.m. on weekdays (Acadia Center Reply Brief at 2-3). Acadia Center also recommends that the Department consider establishing more efficient TOU windows (Acadia Center Reply Brief at 2-3). Finally, Acadia Center asserts that NSTAR Electric's timeline for its proposal to tie revising TOU rates to AMI deployment is "too slow" (Acadia Center Reply Brief at 2-3).

iv. TEC and PowerOptions

TEC and PowerOptions assert that the Company's peak periods for commercial TOU rates must be adjusted to reflect when peak loads occur, which TEC and PowerOptions claim tend to occur over a smaller number of hours than currently reflected in rates (TEC/PowerOptions Brief at 3). TEC and PowerOptions also express concern that customers with interval meters should be able to maintain such meters despite rate consolidation (TEC/PowerOptions Brief at 11). In this regard, TEC and PowerOptions contend that customers with interval meters are able to purchase retail energy based on their actual hourly consumption, and that many such customers have entered into retail energy supply contracts where pricing is based on the availability of interval data (TEC/PowerOptions Brief at 11). As such, TEC and PowerOptions contend that the Department should ensure that customers do not lose the ability to maintain interval meters with the proposed consolidation and streamlined definitions of rates (TEC/PowerOptions Brief at 11). Finally, TEC and PowerOptions assert that the Department should not wait until years after the full deployment of AMI to revise the Company's TOU periods (TEC/PowerOptions Brief at 3; TEC/PowerOptions Reply Brief at 6).

v. UMass

UMass argues that the current definition of on-peak periods used in the Company's distribution rates and tariffs are out of date, they do not accurately reflect when peak conditions occur on the system and, as a result, they send inefficient price signals that discourage efficient use of the grid and they frustrate the Commonwealth's clean energy and climate policies, particularly around investment in and operation of DG (UMass Brief at 30; UMass Reply Brief at 7). UMass asserts that the Department should require that NSTAR Electric revise its on-peak hours for all TOU customers to include the hours between 3:00 p.m. and 7:00 p.m. on weekdays, with all other hours considered off-peak (UMass Brief at 30). UMass also argues that the Company should not wait until deployment of AMI meters to make the recommended change to TOU rates (UMass Brief at 35; UMass Reply Brief at 7).

Further, UMass argues that the Department should direct NSTAR Electric to eliminate demand ratchets in all of its rate designs (UMass Brief at 40). UMass asserts that demand ratchets are misaligned with Department goals and Massachusetts climate policy, are inefficient, and are unfair and complex (UMass Brief at 40-42). UMass contends that demand ratchets place a floor on customers' demand charges, even if those customers draw no power from the grid across all on-peak hours, resulting in inaccurate price signals that do not elicit efficient behavior (UMass Brief at 41-42).

Finally, UMass argues that the Department should not approve the elimination of seasonally differentiated rates (UMass Brief at 45). UMass argues that discontinuing seasonally differentiated rates would be a "step in the wrong direction" with respect to recent legislation (UMass Reply Brief at 8).

vi. Company

The Company argues that its proposals regarding seasonal rates and TOU rates are reasonable and establish consistency (Company Brief at 429; Company Reply Brief at 58). Regarding seasonal rates, NSTAR Electric argues that it is attempting to establish some consistency in its rate design and that the legacy Boston Edison service area is the only area in Massachusetts with seasonal rates (Company Brief at 429, citing Exh. ES-RDC-Rebuttal-1, at 19; Company Reply Brief at 60). Further, the Company asserts that movement away from seasonally differentiated rates is consistent with electrification efforts (Company Brief at 429, citing Exh. ES-RDC-Rebuttal-1, at 19).

With respect to TOU rates, the Company clarifies that it is not seeking to eliminate all TOU rates in this proceeding (Company Brief at 430; Company Reply Brief at 58). Rather, the Company asserts that it is proposing only to end certain optional TOU rates with limited enrollment (Company Brief at 430; Company Reply Brief at 58). Regarding peak period definitions, the Company argues that this proceeding is not the appropriate time to propose changes, and that large bill impacts could result from such a change (Company Brief at 430). The Company contends that any change in TOU definitions will require a change in the pricing and the ratio of peak to off peak pricing (Company Brief at 430, citing Exh. ES-RDC-Rebuttal-1, at 11; Company Reply Brief at 59). According to the Company, a shorter peak window could narrow the revenue collection during peak hours, which would necessitate higher off-peak pricing over a longer window or much higher pricing during the peak hour (Company Brief at 430, citing Exh. ES RDC-Rebuttal-1, at 11; Company Reply Brief at 59). Further, the Company asserts that it will have more information to review alternative rate structures when AMI is fully developed (Company Brief at 430-431; Company Reply Brief at 60).

b. Analysis and Findings

In D.P.U. 17-05-B, at 96, the Department ordered the Company to provide for a more gradual plan for consolidation and alignment in its next general rate filing. The Department supports the eventual goal of consolidation of the Company's rates across its service territory and finds the Company's proposals related to rate class alignment to be a positive step toward achieving one set of rates for the Company. Rate class alignment also allows for greater flexibility to address current and future policy goals and customer needs.

When consolidating rates, the Department has noted that a proposal must consider our rate structure goals of simplicity, efficiency, continuity, equity, fairness, and earnings stability. D.P.U. 17-05-B at 86; D.P.U. 10-55, at 556; G.L. c. 25, § 1A. The proposals related to alignment in the current case speak directly to the rate structure goals of simplicity, efficiency, equity, and fairness, as customers across the Company's service territory will have more consistent rate definitions and offerings.

The Company has proposed to align general service offering demand thresholds (Exh. ES-RDC-1, at 19-20). Customers with average demand below 100 kW annually will generally be served on Rate G-1 (Exh. ES-RDC-1, at 19). Medium C&I customers will primarily be served under Rate G-2 and will be those with demand between 100 kW and 349 kW annually (Exh. ES-RDC-1, at 19). Large C&I customers will primarily be served under Rate G-3 and will be those with demand between 349 kW and 2,500 kW annually. The Large C&I customers are also frequently serviced at the primary voltage level. (Exh. ES-RDC-1, at 21). The Department finds these proposed rate class definitions to be appropriate and, therefore, they are approved.

NSTAR Electric also proposes a new offering within the G-1 rate class; a non-demand-based rate class (Exh. ES-RDC-1, at 5, 41). Such a rate class can provide appropriate price signals to assist new and advancing customer needs, such as electric vehicle charging (Exh. ES-RDC-1, at 42). Therefore, the Department approves the Company's proposed non-demand-based Rate G-1.

The Company also proposes to eliminate the seasonal rate offerings under Commonwealth Electric Rate G-1, and Commonwealth Electric Rate G-7, but maintain the closed seasonal Boston Edison Rate T-1 (Exh. ES-RDC-1, at 41). The Department finds that in order to align with the rest of NSTAR Electric's service territories, the Company's proposal to eliminate the seasonal offerings under Commonwealth Electric Rate G-1 and Commonwealth Electric Rate G-7 is appropriate at this time (Exh. ES-RDC-1, at 41). Therefore, the Department approves the Company's elimination of the seasonal rate offerings under Commonwealth Electric Rate G-1, and Commonwealth Electric Rate G-7. Additionally, the Department accepts the Company's maintaining the closed seasonal Boston Edison Rate T-1.

The Department also finds that the Company's following proposals meet the Department goal of simplicity, further assist in the alignment and consolidation process, and, therefore, are approved: (1) expanding the Boston Edison G-1 rate offering from 10 kW to 100 kW; (2) moving the current Boston Edison G-2 customers to either the expanded Boston Edison Rate G-1 or Boston Edison Rate T-2; (3) renaming the Boston Edison Rate T-2 as Boston Edison Rate G-2 and changing the availability from greater than ten kW to greater than 100 kW; (4) combining Cambridge Electric Light Rates G-0, G-1, and G-4 into Cambridge Electric Light Rate G-1 that encompasses customers with monthly demand up to 100 kW, and cancel Cambridge Electric Light Rates G-0 and G-4; (5) consolidating Commonwealth Electric Rate G-5 customers into new Commonwealth Electric Rate G-1; (6) closing Commonwealth Electric Rate G-7; (7) consolidating WMA Rate G-0, WMA Rate T-0, WMA Rate G-2, and WMA Rate T-4 with monthly demand up to 100 kW into a new WMA Rate G-1; (8) moving the remaining WMA Rate G-0, WMA Rate T-0, and WMA Rate G-2 customers with demand greater than 100 kW to revised WMA Rate G-2 with monthly demand greater than 100 kW and up to 349 kW, thereby eliminating WMA Rate T-0; (9) limiting WMA Rate T-4 to monthly demand greater than 100 kW and up to 349 kW; and (10) renaming WMA Rate T-2 as WMA Rate G-3 (Exh. ES-RDC-1, at 20, 71-72).

Next, the Department finds it reasonable and appropriate to approve the Company's proposal to eliminate the use of block energy rates (Exh. ES-RDC-1, at 8-9). The

Department finds that the Company's proposal to replace the block energy rates with a simple customer charge and energy charge design is consistent with the goal of simplicity.

The Company has reduced, but still maintains, some demand ratchets (Exh. ES-RDC-1, at 45). The Department recognizes that, in some instances, demand ratchets may be misaligned with the goals to establish efficient, fair, and simple rate structures. Further, demand ratchets may conflict with Massachusetts' climate policy and the Department's statutory mandates to prioritize reducing GHG emissions and increasing energy efficiency. Nonetheless, based on continuity concerns, we find it inappropriate to eliminate all demand ratchets in the instant proceeding. Thus, the Company shall retain a demand ratchet for existing customers currently taking service under proposed Boston Edison demand Rate G-1, in which customers with usage greater than 10 kW pay a demand charge but those customers with usage at or under 10 kW do not (Exhs. ES-RDC-1, at 45; ES-RDC-2, Sch. 1, at 1 (Rev. 3)). Similarly, the Company shall retain a demand ratchet for customers taking service under WMA Rate 24, and Commonwealth Electric proposed Rate G-1 demand, in which a demand ratchet is used for existing customers with demand meters and usage above 2 kW (Exhs. ES-RDC-1, at 45; ES-RDC-2, at 1 (Rev. 3)). Further, the Department directs the Company and all EDCs to address the merits of demand ratcheted rates in their next base distribution rate filings, and, if warranted, to include a proposal or plan to eliminate the use of ratcheted rates.

The Company states that all currently effective, optional TOU rates have been closed except for Cambridge Electric Light Rate G-4, Commonwealth Electric Rate G-7, WMA Rate T-0, and WMA Rate T-4 (Exh. ES-RDC-1, at 11). The Company proposes to transfer Cambridge Electric Light Rate G-4 customers to the non-demand, proposed Cambridge Electric Light Rate G-1; close Commonwealth Electric Rate G-7; and consolidate WMA Rate T-0 into the non-demand, proposed WMA Rate G-1 (Exh. ES-RDC-1, at 11). Several intervenors argue that the peak periods should be adjusted, and that the Department need not wait until AMI deployment to do so (Attorney General Brief at 171-173; DOER Reply Brief at 8; Acadia Center Reply Brief at 2-3; TEC/PowerOptions Brief at 3; TEC/PowerOptions Reply Brief at 6; UMass Brief at 35; UMass Reply Brief at 7).

The Department finds that the Company's peak and off-peak hours should be refined, and, for TOU rates, should better reflect actual distribution system demand costs. The current TOU time periods available to the Company's customers are very broad and pre-date electric industry restructuring. The TOU offerings proposed to be eliminated have limited enrollment as well. Nonetheless, we share the Company's concern that adjusting the peak period at this time may be disruptive to ratepayers (Exhs. ES-RDC-Rebuttal-1, at 11; AG 40-4). As such, we find that it is more appropriate to address revised peak periods once the Company has moved forward on AMI implementation and we have more information to review alternative rate structures that will benefit customers and achieve public policy objectives. See, e.g., G.L. c. 164, § 92B (electric sector modernization plans); D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 201, 327 & n.136. Based on these considerations, we approve the Company's proposal to transfer existing TOU customers to different rate classes, as identified above.

Finally, the Department finds that it is reasonable and appropriate for customers impacted by rate alignment efforts to continue to use interval meters to utilize the competitive retail electricity market. In particular, we recognize that many of these customers have entered into multi-year competitive electricity supply contracts that are predicated upon a load shape informed by interval metering data, and that a switch from interval meter data to a profiled load during a rate consolidation has the potential to disrupt pre-existing electricity supply contractual arrangements (Exh. SUR-TEC/PO-JDB-1, at 12).

4. Distribution Rate Design

a. Introduction

NSTAR Electric proposes to collect $1,261,038,188 in base distribution revenues (Exh. ES-REVREQ-2, Sch. 1 (Rev. 4)). In allocating revenues to rate groups, the Company departed from traditional revenue allocation in that it proposes to first develop target revenues by rate group, and then by rate classes within each group (Exh. ES-RDC-1, at 27-28, 30). The Company states that this variation of the traditional target class revenue allocation first to rate groupings, and then to rate classes, was utilized in an effort to align rate classes within each group and create a path to equalization of rates (Exh. ES-RDC-1, at 30). The Company developed rate groups by aggregating the revenue requirement for similar rate classes as follows: residential customers, small C&I customers, medium C&I customers, large C&I customers, Company-owned streetlights, and customer-owned streetlights (Exh. ES-RDC-1, at 30).

The Company performed four steps to construct the base distribution revenue requirement for each rate group (Exh. ES-RDC-1, at 27). First, the Company simulated current test-year revenues using rates in effect on January 1, 2022, and test-year billing quantities (Exhs. ES-RDC-1, at 27; ES-RDC-2 (Rev. 3)).[201] Second, the Company performed an ACOSS to determine the revenue requirement by rate class at EROR, as discussed in Section XVII.B.2 (Exhs. ES-RDC-1, at 27, 31; ES-ACOS-2 through ES-ACOS-5 (Rev. 3); ES-RDC-2 through ES-RDC-5 (Rev. 3)). Third, the Company summed the individual class revenue requirements at EROR for each of the proposed residential, small general service, medium general service, large general service, Company-owned streetlights, and customer-owned streetlights groups (Exh. ES-RDC-1, at 31). As part of the third step, the Company also included the proposed transfer of $46,794,254 associated with the SECRF, the RTW factor, and the SMART factor into current base distribution rates[202] for the purpose of applying the 200-percent base distribution rate cap (Exhs. ES-RDC-1, at 24-25; ES-RDC-2, Sch. 4-9 (Rev. 3); ES-REVREQ-2, Sch. 1, at 9 (Rev. 4)). The Company made an offsetting adjustment to reconciling revenues to reflect the change in the reconciling revenues to the total increase in rates when applying the ten-percent total revenue cap (Exhs. ES-RDC-2, Sch. 4-9 (Rev. 3); ES-REVREQ-2, Sch. 1,

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201 Beginning with its May 13, 2022, updated ACOSS, the Company provided its rate design using 2021 billing determinants to derive its allocated costs.

202 The Company proposed to transfer $21,700,536 for the SECRF, $23,200,000 for the RTW factor, and $1,893,718 for the SMART factor.

at 9). The adjustment also reflected the increase in basic service charges resulting from the alignment of some customer classes among the small and medium C&I rate groupings (Exh. ES-RDC-1, at 25-26). Further, the Company increased the Residential Assistance Adjustment factor ("RAAF") revenues resulting from the proposed increase in the low-income discount rate (Exhs. ES-RDC-1, at 27; ES-RDC-2, Sch. 4-10 (Rev. 3)).

Fourth, the Company applied rate group impact constraints of a ten-percent cap on the increase to total revenues, net of proposed reconciling mechanism revenue changes, from the change in base distribution revenues, followed by a 200-percent cap on base distribution revenues from the average increase to base distribution revenues, and then a zero-percent rate increase floor to derive target revenues by rate group (Exhs. ES-RDC-1, at 28, 30-34; ES-RDC-2, Sch. 5 (Rev. 3)).

Next, the Company calculated the rate class revenue targets using the following steps. First, the Company calculated an average distribution unit cost for each rate group by dividing its target revenue derived in the previous step by the amount of its test year kWh sales for the residential, small general service, and street lighting groups and by its test year billing demand for the medium general service and the large general service groups (Exhs. ES-RDC-1, at 31-34; ES-RDC-2, Sch. 5-9 (Rev. 3)). Second, for each rate class the applicable group average distribution unit cost was multiplied by the applicable test year billing determinants for that rate class to determine a total distribution revenue target prior to applying the rate class impact constraints (Exhs. ES-RDC-1, at 31-34; ES-RDC-2, Sch. 5-9 (Rev. 3)). Third, the Company applied a ten-percent cap on the increase to total revenues, net of proposed reconciling mechanism revenue changes, from the change in base distribution revenues and allocated any rate class revenue that exceeded the cap to rate classes within the rate group that did not exceed the cap. Similarly, the Company applied a 200 percent cap on base distribution revenues from the average increase to base distribution revenues and allocated any rate class revenue within the rate group that exceeded the cap to rate classes within the rate group that did not exceed the cap. Finally, the Company applied a zero-percent floor in distribution revenue decreases and allocated any excess distribution revenue to rate classes within the rate group that did not reach the floor (Exhs. ES-RDC-1, at 27, 30-31; ES-RDC-2, Sch. 6-9 (Rev. 3)).

With respect to rate class impact constraints and the rate class revenue allocation process, the Company states that in D.P.U. 13-90, the Department elaborated that to conform to Section 94I, the following steps should be taken: (1) calculate total revenues for each rate class using the most recently effective rates; (2) calculate the revenue cap for each rate class at ten percent of the total revenues for each rate class; (3) determine if any rate class will receive a base rate increase greater than this revenue cap when designing rates at EROR; and (4) for those rate classes that have a base distribution rate increase that exceeds the cap, allocate the total amount over the cap to the rate classes that are under the cap based on their current base rate revenue levels (Exh. ES-RDC-1, at 29). The Company also notes that in D.P.U. 15-155 and D.P.U. 15-80/15-81, the Department directed both companies to allocate the revenue requirement that exceeds the ten-percent cap to those rate classes that did not exceed the cap based on their distribution revenue requirements at EROR (Exh. ES-RDC-1, at 29). The Company states that it applied the aforementioned constraints to limit rate group and rate class revenue increases to ten percent of total revenue and 200 percent of the average distribution revenue increase (Exh. ES-RDC-1, at 28).

In D.P.U. 20-120, at 485, the Department directed all distribution companies to include a proposal in future base distribution rate cases to eliminate cross subsidies over time if the increase to any one rate class based on EROR exceeds ten percent (Exh. ES-RDC-1, at 36-37). In its initial filing, the Company proposed that an initial attempt to eliminate class cross-subsidies should be made by restricting allocations of revenues exceeding the ten-percent cap between residential and general service (including streetlights) customer groups (Exh. ES-RDC-1, at 36-37). The Company proposed that any revenue exceeding the ten-percent cap from a residential rate class would not be allocated to any general service rate class and no revenue exceeding the ten-percent cap from a general service rate class would be allocated to a residential rate class (Exh. ES-RDC-1, at 36-37). The Company also proposed that if this restriction could not be met (i.e., all rate classes in either the general service or residential group exceed the ten-percent cap), then the allocation of revenue across residential and general service groups would be allowed (Exh. ES-RDC-1, at 37). While the Company's streetlighting rate group exceeded the ten-percent cap when the ACOSS was initially filed, the Company did not implement the aforementioned reallocation in its initial filing, because the Department's Order in D.P.U. 20-120 was issued on September 30, 2021, and the Company's target revenue allocation process was at a late stage (Exh. ES-RDC-1 at 37). However, the Company took the opportunity to implement the reallocation when it filed its first revised ACOSS on May 13, 2022 (Exh. RDC-2, Sch. 5 (Rev. 1). The Company reallocated the excess revenues to other general service rate groups, but not to the residential rate group (Exh. ES-RDC-2, Sch. 5 (Rev. 3)).

After applying the ten-percent total revenue cap, the Company applied the 200-percent base distribution revenue cap, which was exceeded by Rate S-2, customer-owned streetlights, in the amount of $80,430 (Exh. ES-RDC-2, Sch. 5 (Rev. 3)). After allocating the excess revenues to the remaining non-residential rate groups, the Company implemented a revenue floor for base distribution revenue increases of zero dollars, though no rate group triggered this rate floor and, as such, no reallocation was necessary (Exh. ES-RDC-2, Sch. 5 (Rev. 3)). As explained above, the Company used the final revenue allocations by rate group to determine the target revenue allocation to individual rate classes (Exh. ES-RDC-1, at 31). In applying the rate class impact constraints to rate classes, numerous classes also experienced revenue increases in excess of the ten- and 200-percent caps (Exhs. ES-RDC-5; ES-RDC-2, Schs. 6 through 9 (Rev. 3)).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company, without justification or evidentiary support, applied the revenue allocation constraints in contravention of Department precedent established in D.P.U. 19-120 and that this error impacted the final revenue requirement (Attorney General Brief at 160, citing Exhs. AG-DED-Surrebuttal-1, at 9-10; CLC-JDW-1, at 6; Attorney General Reply Brief at 45-46). In particular, the Attorney General contends that NSTAR Electric's proposed revenue allocation process suffers from two significant errors: (1) the Company applied the Department's constraints (i.e., overall statutory ten-percent total revenue cap, rate increase floor, and relative distribution percent rate increase) in the wrong order; and (2) the Company's proposed allocation results in rate class revenue re-allocations being confined within each proposed rate group (Attorney General Brief at 160-162, citing Exhs. AG-DED-Surrebuttal-1, at 10-11; CLC-JDW-1, at 21).

The Attorney General recommends that the Department require the Company to implement its revenue allocation process consistent with the Department's Order in D.P.U. 19-120 (Attorney General Brief at 161, citing Exh. AG-DED-Surrebuttal-1, at 11). Specifically, the Attorney General argues that the Company should implement its approved revenue allocation with three constraints in the following order: (1) cap the overall total rate increases of no greater than ten percent; (2) apply a rate increase floor of zero percent ensuring that no rate class received a rate decrease in the context of an overall rate increase; and (3) cap the allowed base distribution rate increases equal to a percent multiple of the system average increase (Attorney General Brief at 161, citing D.P.U. 19-120, at 487 (Department Schedule 10); Tr. 8, at 859-862). According to the Attorney General, NSTAR Gas also implemented this order in its final revenue allocation compliance filing approved by the Department (Attorney General Brief at 160-161, citing Tr. 8, at 862).

The Attorney General also disagrees with the Company's proposal to restrict the reallocation of revenues that exceed a constraint to only other rate classes that were part of the same rate group (Attorney General Brief at 160). The Attorney General argues that because the Company performed its class cost of service study on a rate class basis, this restriction is unnecessary and counter-productive to an overall approach of bringing individual rate classes towards their full cost of service and reducing cross-subsidizes (Attorney General Brief at 162, citing Exh. AG-DED-Surrebuttal-1, at 10-11).

Further, the Attorney General argues that the Company's proposed class rate increases are excessive and inconsistent with rate continuity principles (Attorney General Brief at 162). The Attorney General contends that, to provide greater rate continuity, the Department should limit the base distribution rate increase to any single customer class by 1.25 times the overall system average increase, after the application of the statutory ten-percent cap in total overall rates (Attorney General Brief at 163, 165, citing Exh. AG-DED-1, at 11). According to the Attorney General, this limit would reduce the maximum revenue increase in base distribution rates to any single customer class to 15.88 percent, as opposed to the Company's proposed 25.4-percent maximum increase (Attorney General Brief at 163, 165, citing Exhs. AD-DED-1, at 12; AG-DED-3, Schs. 1, 2). Finally, the Attorney General recommends that rate increases that exceed the statutory ten-percent cap in total rates be phased in over the course of the Company's proposed multi-year rate plan (Attorney General Brief at 163-164, 165, citing Exh. AG-DED-1, at 12).

ii. Cape Light Compact

Cape Light Compact asserts that NSTAR Electric made two significant errors in following Department precedent in its revenue allocation (CLC Brief at 9). Specifically, Cape Light Compact argues that the Company performed the revenue increase constraints in the incorrect order and incorrectly applied the revenue floor to base distribution revenues rather than to total revenues (CLC Brief at 9-12, 17-18; CLC Reply Brief at 4). Cape Light Compact further contends that NSTAR Electric's proposed target revenue allocation process results in unjust and unreasonable rate decreases to four general service rate classes (CLC Brief a 14-16).[203] Cape Light Compact asserts that these four rate class decreases create an unfair class subsidy in favor of small and medium general legacy Boston Edison customers over small and medium general customers in other parts of the Company's service area (CLC Brief at 16).

Cape Light Compact argues that NSTAR Electric's proposed target revenue allocation should be rejected, and that the Company should be required to revise its revenue allocation consistent with Department precedent in D.P.U. 19-120 (i.e., proper ordering of the caps and floors and application of the floor based on total revenues) (CLC Brief at 16-18). According to Cape Light Compact, following the method established in D.P.U. 19-120 will result in small rate classes receiving a disproportionate credit or significant violations of the floor in subsequent application of the 200-percent cap because it is applied after the floor (CLC Brief at 16, citing Exh. CLC-JDW-1 at 10-11). Cape Light Compact asserts that this issue can be resolved with two modifications – (1) if more than one iteration of the floor is necessary, the credit from reapplying the floor in subsequent iterations could be allocated to rate classes that

203 The four rate classes are: Rate G-1/T-1 (Boston Edison); Rate G-5 (Commonwealth Electric); Rate G-2 (Boston Edison); and Rate WR (Boston Edison) (CLC Brief at 16).

already benefitted from the ten-percent cap, and (2) where the total revenue increase is very nearly zero, rather than applying the floor, each rate in the affected class could receive the same increase in the revenue requirement (CLC Brief at 16, citing Exh. CLC-JDW-Surrebuttal-1 at 13; CLC Reply Brief at 2-3).

iii. TEC and PowerOptions

TEC and PowerOptions argue that the Section 94I cap allocation process serves the dual purpose of limiting rate shock while moving closer to cost-based rates over time (TEC/PowerOptions Reply Brief at 10). Further, they contend that the dual purpose of the ten-percent and 200-percent caps, in that order, was important to ensure that rates are ultimately cost based and provide continuity in the form of measured increases for rates that are not delivering their costs of service at EROR (TEC/PowerOptions Reply Brief at 10). In addition, TEC and PowerOptions claim that the order in which the constraints are applied is important because a rate that is adjusted in excess of its cost of service should not be required to bear additional cross subsidies beyond the addition of revenue required for the revenue floor adjustment (TEC/PowerOptions Reply Brief at 11). TEC and PowerOptions, however, disagree with Cape Light Compact's recommendation to apply a total revenues floor (TEC/PowerOptions Reply Brief at 11).

According to TEC and PowerOptions, the Department should order that the sequence of operations proceed as follows: (1) apply the ten-percent cap; (2) apply base distribution revenue floor to ensure that no rate class experiences a rate decrease; (3) apply the revenue addition from the base distribution revenue floor as a credit to excess revenues allocated as part of the ten-percent cap; and (4) apply the 200-percent cap excluding rate classes subject to a revenue floor adjustment from bearing additional allocation of revenue from other classes in excess of the 200-percent cap (TEC/PowerOptions Reply Brief at 12).

iv. Company

The Company summarizes its distribution rate allocation process (Company Brief at 392-399). In response to the intervenor positions, NSTAR Electric asserts that, overall, the Company's process in developing its proposed rate design and subsequent revenue allocation through analyzing and applying the Department's long-standing rate design goals is consistent with Department precedent, despite not implementing the same process applied in D.P.U. 19-120 (Company Brief at 420-421, citing Exhs. ES-RDC-1, at 6; ES-RDC-Rebuttal-1, at 7-8). According to the Company, there is no Department requirement regarding the proposed sequencing of the overall statutory ten-percent cap, rate increase floor, or relative distribution-percent rate increase (Company Brief at 421). Rather, the Company contends that the Department is not precluded from considering appropriate alternative allocation methods than the method used D.P.U. 19-120 (Company Brief at 421, citing D.P.U. 19-120, at 421). The Company asserts that its revenue allocation process, although not consistent with D.P.U. 19-120, nevertheless is consistent with the Department's rate design objectives and balances various ratemaking objectives, such as efficiency and rate stability (Company Brief at 421, citing Exhs. ES-RDC-1, at 40; ES-RDC-Rebuttal-1, at 5, 7-8).

Further, NSTAR Electric argues that Cape Light Compact's recommendation to apply a total revenues floor is also inappropriate, as it would leave the Company with no control over the level of distribution pricing because the final distribution rates become a by-product of the total revenue floor (Company Brief at 421, citing Exh. ES-RDC-Rebuttal-1, at 7). The Company maintains that a floor on total revenue forces further reallocation of distribution revenue targets and prevents rates from ever reflecting the cost of service (Company Brief at 421, citing Exhs. ES-RDC-Rebuttal-1, at 7; DPU 36-6).

NSTAR Electric also rejects the Attorney General's argument that the Company's proposed allocation process results in rate class revenue reallocations being confined within each proposed rate group (Company Brief at 421). In addition, the Company disputes Cape Light Compact's assertion that the allocation process results in unjust and unreasonable rate decreases for four general service rate classes (Company Brief at 421). The Company argues that its proposed rate class groupings were established based on continuity and simplicity and are necessary to make progress in aligning the pricing among legacy rate classes (Company Brief at 421, citing Exhs. ES-RDC-1, at 21; DPU 11-6).

c. Analysis and Findings

As a first step in its revenue allocation process the Company appropriately began its allocation with revenues at EROR per the ACOSS (Exh. ES-RDC-1, at 28). The Company then grouped customer classes into six groups based on the proposed characteristics for each class and group: residential rate classes, small C&I rate classes, medium C&I rate classes, large C&I rate classes, Company-owned streetlights, and customer-owned streetlights

(Exh. ES-RDC-1, at 16). The Company grouped its rate classes in an effort to align the availably characteristics of similar rate classes, as a step toward rate consolidation in the future (Exh. ES-RDC-1, at 22). After determining the appropriate target revenue, by applying the rate constraints to the revenue requirement at EROR for each rate group, the Company applied the resulting target revenues' unit costs to each rate class within each group, and then within each rate group applied again the rate class revenue constraints to derive each rate class's final base distribution revenue requirement (Exh. ES-RDC-1, at 30-31). The Department finds that the foregoing steps reflect reasonable efforts to align the availability characteristics of similar rate classes.

In applying its group and rate class revenue constraints, the Company took into consideration its proposed transfer to base distribution rates of revenues currently recovered through the SECRF, SMART factor, and the RTW factor, along with the change to the RAAF associated with increasing the low-income discount rate (Exhs. ES-RDC-1, at 24-25, 27; ES-RDC-2, Sch. 4-10 (Rev. 3); ES-REVREQ-2, Sch. 1, at 9 (Rev. 4)). In Section XIV.A.4 above, the Department disallowed the transfer of SMART Program investments to base distribution rates, and in Section XI.C.4.b above, the Department disallowed the transfer of the RTW Program costs to base distribution rates. Moreover, in Section XVII.C.3 below, the Department approved an increase to the low-income discount from 36 percent to 42 percent. Also, in Section XV.C.2 above, the Department directed the Company to remove meter-related capital from base distribution rates and, instead, recover these costs through the AMI reconciling factor. Accordingly, in its compliance filing, the

Company shall adjust the base distribution revenues to comply with these directives, for the purpose of applying the 200-percent base distribution rate cap (Exhs. ES-RDC-2, Sch. 4-9 (Rev. 3); ES-REVREQ-2, Sch. 1, at 9 (Rev. 4)). In addition, to comply with these directives, the Company shall make offsetting adjustments to reconciling rate revenues for the purpose of applying the ten-percent total revenue cap.

Next, the Company applied a series of revenue constraints. The Company proposes a distribution rate allocation process that does not follow the order set forth in D.P.U. 19-120, at 487 (see Exhs. ES-RDC-1, at 28, 30-34; ES-RDC-2, Sch. 5 (Rev. 3)). In D.P.U. 19-120, the Department applied revenue constraints in the following order: ten-percent cap on the total revenue increase, followed by the zero percent floor on distribution revenue, followed by a 200 percent cap on overall distribution revenue increase. D.P.U. 19-120, at 487. However, we note that in D.P.U. 20-120, the Department applied revenue constraints in the following order: ten-percent cap on the total revenue increase, followed by a 200-percent cap on overall distribution revenues, and no revenue floor. D.P.U. 20-120, at 538-540. In the instant case, NSTAR Electric applied the ten-percent cap on total revenue increase, followed by a 200-percent cap on the overall distribution revenue increase, followed by the zero-percent floor on distribution revenue to ensure that a rate class does not receive a distribution rate decrease (Exhs. ES-RDC-1, at 28, 30-34; ES-RDC-2, Sch. 5 (Rev. 3)).

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 must prevent any class from subsidizing another class unless a clear record exists to support such subsidies, or unless such subsidies are required by statute. D.P.U. 19-120, at 431. To achieve such balance, flexibility in the revenue allocation method may be warranted, so long as the results do not violate our rate structure goals or result in unjust or unreasonable rates. Without such flexibility, the Department cannot develop rates that adequately allow for the consideration of efficiency, simplicity, continuity, fairness, and stability. As such, we decline to adopt the intervenors' recommendations to strictly follow the revenue constraints set forth in D.P.U. 19-120. In addition, we find that implementing a floor on distribution revenue increases at zero percent mitigates intervenor concerns regarding the subsidization of legacy Boston Edison small and medium general service customers by small and medium general service customers in other legacy service areas.

As noted, the Company began its allocation process by applying the ten-percent total revenue cap as mandated by Section 94I first to each customer rate group[204] to determine the unit cost and later to each proposed rate class within each customer rate group (Exh. RDC-2, at Sch. 5 (Rev. 3)). In D.P.U. 20-120, at 485, the Department directed all gas and electric companies to 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 EROR exceeds ten percent. The Company suggested that one option would be to restrict revenues that exceeded the ten-percent cap between residential and general service customer groups, inclusive of streetlights (Exh. ES-RDC-1, at 36-37). Beginning with its first revised ACOSS and

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[204] Residential, small C&I, medium C&I, large C&I, customer-owned streetlights, and Company-owned streetlights.

continuing through later iterations, the Company implemented this proposal to reallocate the overage from its streetlighting rate group; the overage was assigned to other general service rate groups, but not to the residential rate group (Exh. ES-RDC-2, Sch. 5 (Rev. 3)). Notwithstanding our decision below, to address our goals of continuity and fairness and to maintain the flexibility required to properly balance our rate structure goals, no rate group should be exempt from being allocated any revenues in excess of the ten-percent cap. The Department is not convinced that restricting revenues that exceed the ten-percent cap between residential and general service customer groups will assist in eliminating cross subsidies over time. Moreover, the Company did not submit a specific proposal regarding the D.P.U. 20-120 directive when applying the ten-percent cap to each rate class within each group. Nevertheless, in this instance, we accept the Company's implementation of the Section 94I ten-percent cap at the rate class level within each group because it will help with the future alignment of the Company's C&I rate classes. Therefore, in its compliance filing, the Company shall include all rate groups in the reallocation of revenues in excess of the rate group revenue constraint caps, and we accept the Company's application of the ten-percent cap to individual rate classes within each rate group. We reiterate that all gas and electric companies shall 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 EROR exceeds ten percent. D.P.U. 20-120, at 485.

The Company next proposes for each rate class a distribution revenue increase cap of 200 percent (or a multiplier of 2.0) of the system overall increase (Exh. ES-RDC-1, at 28).

The Attorney General argues that a multiplier of 1.25 is more appropriate (Attorney General Brief at 163, 165, citing Exh. AG-DED-1, at 11). As noted above, the Department balances numerous principles when determining the appropriate multiplier to apply to the average increase in base distribution rates. The Department finds that use of a 2.00 multiplier adequately balances the principle of fairness with resulting customer bill impacts. D.P.U. 18-150, at 583; D.P.U. 17-05-B at 325.

Next, the Company applied a zero-percent revenue floor to its proposed base distribution rates after applying the ten-percent and 200-percent rate caps (Exh. ES-RDC-2, Sch. 5 through Sch. 9 (Rev. 3)). Cape Light Compact argues that the floor should be applied to total revenues, not just base distribution revenues (CLC Brief at 17-18; CLC Reply Brief at 4-5). The Department finds it reasonable to accept the Company's zero-percent distribution revenue floor, as it will limit the increases to other rate classes and will meet the Department's goal of fairness (Exh. DPU 36-6). Further, we find that setting the revenue floor using base distribution revenues provides a more equitable result, as reconciling revenues, which vary from year to year, are excluded. 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 (Exh. ES-RDC-Rebuttal-1, at 7). For these reasons, the Department directs the Company in its compliance filing to apply a zero-percent floor on base distribution revenues as the last revenue constraint in its allocation process.

Based on our findings above, we conclude that the Company's revenue allocation process is reasonable and appropriate and will result in just and reasonable rates. Accordingly, we approve this aspect of the Company's rate design.

5. Transmission Rate Allocation and Design

a. Introduction

The Company states that transmission rates are currently allocated to rate classes based on the twelve-month coincident peak ("12 CP") method, meaning that the Company's total retail transmission revenue requirement is allocated to rate classes based on each class's contribution to the annual coincident peak experienced on the transmission system for a particular year (Exh. ES-RDC-1, at 22). The allocated revenue requirement is then translated into a rate using the approved rate design for the class (Exh. ES-RDC-1, at 22). As such, each rate class has its own unique transmission rate (Exh. ES-RDC-1, at 22). Individualized rates and unique rate designs present a challenge to any effort to consolidate rates, but the Company proposes to alter the transmission allocation method as part of its overall rate alignment efforts (Exh. ES-RDC-1, at 22-23).

As with distribution rates, the Company proposes to categorize rate classes into the five distinct rate groups discussed above, with the customer-owned streetlighting and the Company-owned streetlighting combined into one rate group and to allocate the transmission revenue requirement to each of the rate groups using the 12 CP method (Exh. ES-RDC-1, at 23). However, because the difference between an individualized rate class allocation and the applicable rate group allocation is too large for certain classes, the Company does not propose a single allocation by rate group to apply to all rate classes within a group (Exh. ES-RDC-1, at 23). With respect to WMA Rate T-5, the 12 CP method is applied to individual customer billing for transmission rates (Exh. ES-RDC-6, Sch. 2, at 188). In this method of billing, customers are first charged based on monthly non-coincident peak demand but are subsequently rebilled based on their coincident-peak demand (Exh. UMass 1-7; Tr. 8, at 827). For other large general service rate classes, the Company bills customers on their monthly non-peak demand (Exh. UMass 1-7).

The following table includes an illustrative depiction of the Company's proposed transmission revenue allocation:

Rate Group	**Proposed Rate Class**	**Allocation of Transmission Revenue Requirement**
Residential	R-1/R-2, R-3/R-4	44.14%
Small General Service	G-1 (ALL), T-1 (Boston Edison), G-5 (Cambridge Electric Light), G-6 (Commonwealth Electric), 24 (WMA) G-7 (Commonwealth Electric) 23 (WMA)	19.30% 0.22% 0.0002%
Medium General Service	G-2 (ALL), T-4 (WMA)	19.22%
Large General Service	G-3 (ALL), T-5 (WMA) WR (Boston Edison)	16.59% 0.26%
Streetlights	S-1/S-2	0.28%

Exh. ES-RDC-2, Sch. 3, at 3 (Rev. 3).

NSTAR Electric also proposes a change in transmission rate design for certain rate classes in the small general service group to better align with the proposed distribution rate designs and the Company's movement toward more energy-focused rate design for this group of customers (Exh. ES-RDC-1, at 23). The Company states that, while transmission rate design changes are only proposed for the small general service group, all rate classes will experience rate changes because the proposed allocation is revenue neutral in total (Exh. ES-RDC-1, at 24). The Company provides the following table to summarize the proposed transmission rate design changes:

Legacy Rate Class	**Proposed Transmission Rate Design Change**
G 1NDMD (Boston Edison), T-1 (Boston Edison), G-0 (Cambridge Electric Light), G-6 (Cambridge Electric Light), G-1 (Commonwealth Electric), G-5 (Commonwealth Electric), G-6 (Commonwealth Electric), 23 (WMA), 24 (WMA)	None
G-1DMD (Boston Edison)	Convert from two-part demand/energy rate to energy only rate
G-2 (Boston Edison) (< =100 kW customers only), T-2 (Boston Edison) (< =100 kW customers only), G-1 (Cambridge Electric Light), G-4 (Cambridge Electric Light), G-7 (Commonwealth Electric) G-0 (WMA) (< =100 kW customers only), T-0 (WMA) (< =100 kW customers only), G-2 (WMA) (< =100 kW customers only), T-4 (WMA) (< =100 kW customers only)	Convert from demand-only rate to energy-only rate
G-5 (Cambridge Electric Light)	Convert from inclining block energy rate to flat energy-only rate
G-4 (Commonwealth Electric)	Convert from two-part demand/energy rate to energy-only rate

Exh. ES-RDC-1, at 24.

b. Positions of the Parties

i. TEC and PowerOptions

TEC and PowerOptions request two revisions to the Company's transmission rate design and offerings (TEC/PowerOptions Brief at 5-10). First, TEC and PowerOptions request that the Company expand coincident peak transmission billing from customers taking service under WMA Rate T-5 to all large customers in the Company's EMA service territory (TEC/PowerOptions Brief at 5). TEC and PowerOptions argue that the Department should expand the availability of coincident peak transmission billing on an opt-in basis to large customers who have flexible loads and/or DG that can reduce demands during transmission system peak hours (TEC/PowerOptions Brief at 8).

TEC and PowerOptions assert that the Department has previously found that coincident peak billing for transmission eliminates inequities by charging customers based on their individual consumption at the time of system peak (TEC/PowerOptions Brief at 5, citing D.P.U. 10-70-B at 5). Further, TEC and PowerOptions contend that the Department has previously found that coincident peak billing is consistent with cost causation principles and can produce benefits by reducing congestion during system peak hours, leading to flatter load profiles and system utilization and reducing long-term transmission costs (TEC/PowerOptions Brief at 5, citing D.P.U. 10-70-B at 5; Western Massachusetts Electric Company, D.P.U. 12-97, at 13-14 (2013)). Furthermore, TEC and PowerOptions argue that customers taking service under Rate T-5 in the WMA service area have had coincident peak transmission billing for approximately eight years and appear to be responding to price signals and reducing load during monthly peak hours (TEC/PowerOptions Brief at 5, citing Exh. TEC/PO-JDB-1; Tr. 8, at 928).

TEC and PowerOptions assert that should the Department agree with expanding 12 CP billing to more large customers, that customers wishing to opt in to such a billing option should be required to post deposits and pay for incremental administrative costs associated with bill generation (TEC/PowerOptions Brief at 8, citing RR-DPU-35). TEC and PowerOptions also recommend that expansion of coincident peak billing in the Company's EMA service area should be limited to an initial pilot of approximately 35 customers in the G-3 customer group, with a waiting list if necessary (TEC/PowerOptions Brief at 8, citing RR-DPU-36). To address automating the Company's systems to accommodate 12 CP transmission billing in the future, TEC and PowerOptions assert that the Department should ensure that AMI and CIS systems have the ability to automate such billing structures to reduce the administrative effort associated with implementing this rate design at this time (TEC/PowerOptions Brief at 8-9).

Additionally, TEC and PowerOptions recommend changes to the Company's proposed consolidated Rate G-1, which has both non-demand and demand-based rate options (TEC/PowerOptions Brief at 9). TEC and PowerOptions argue that the Company's proposed G-1 demand customers' transmission rate is a volumetric charge, which would result in an inequity to high load factor customers with their paying much more for transmission service than they would under a demand charge (TEC/PowerOptions Brief at 9; TEC/PowerOptions Reply Brief at 3). Thus, TEC and PowerOptions assert that the Department should direct the

Company to implement a demand-based transmission rate for Rate G-1 demand customers (TEC/PowerOptions Brief at 9).

ii. UMass

UMass asserts that new laws require the Department to prioritize GHG emission reductions and to consider the impacts of rate design decisions on the deployment of DER that support the Commonwealth's climate and clean energy policies (UMass Brief at 20-21, citing 2022 Clean Energy Act, §§ 56 & 57; 2021 Climate Act, § 15; G.L. c.164, §§ 141, 142; UMass Reply Brief at 3-5). Thus, UMass argues that it is critical for the Department to prioritize efficient rate structures that support the Commonwealth's clean energy and climate policies (UMass Brief at 20-25). In this regard, UMass contends that the time is right to expand access to the T-5 rate structure (UMass Brief at 20; UMass Reply Brief at 5-6).

UMass asserts that transmission charges are particularly amenable to efficient rate design because they are assigned to the Company based on a known tariff formula (UMass Brief at 12). Further, UMass contends that the T-5 rate has been in effect for years in the WMA service area and has proven that it affects customers' decision-making on grid usage and that provides significant customer benefits (UMass Brief at 12-13). In addition, UMass argues that the T-5 rate should send efficient price signals that encourage customer action, such as deploying energy storage and on-site generation, which would support Massachusetts energy and climate policies (UMass Brief at 13-15). UMass also claims that a T-5 rate structure for transmission charges is superior to the other structures proposed by the Company vis-à-vis the Department's rate structure goals of simplicity, continuity, fairness, and earnings stability (UMass Brief at 13, 25-27). In particular, UMass asserts that amending transmission rates for large general service customers will affect only the Company's largest customers, who are well equipped to respond to the resulting price signals and capable of doing so (UMass Brief at 13).

UMass asserts that the Department should require that NSTAR Electric expand its T-5 rate design to all large general service customers in the EMA and WMA service areas starting in January 2024 (UMass Brief at 13, 27-29). Further, UMass asserts that the Department should require NSTAR Electric to assess monthly transmission charges to all its large general service customers based on their average 60-minute grid demand during the hour in which the Company's applicable Regional Network Service load peaks for that month, as the Company currently does for T-5 customers (UMass Brief at 13, citing Exh. UMASS-EP/RS-1, at 28).

iii. Company

The Company argues that 12 CP transmission billing should not be expanded to all large general service customers. First, the Company contends that it needs to collect the costs associated with the system that has been constructed to serve large general service customers, and if these large general service customers reduce demand during the system peak for the month, transmission costs for that month will be reduced only to the extent that such activity was not forecasted by the Company (Company Brief at 431-432, citing Exh. ES-RDC-Rebuttal-1, at 10).

Second, the Company claims that 12 CP transmission billing is inefficient in that it produces a price signal that cannot be acted upon since the coincident peak is not known until the billing month has concluded (Company Brief at 432, citing Exhs. ES-RDC-Rebuttal-1, at 11; DPU 58-4; UMASS-ES 1-7). The Company asserts that some customers with DG may be able to reduce load around a board time space to cover the anticipated coincident peak, but less sophisticated customers and those without DG may not be able to pinpoint accurately the moment at which they should curtail use in order to lower their overall cost (Company Brief at 432). Thus, the Company argues that 12 CP transmission billing provides an accurate basis for consumer decisions (Company Brief at 433-434).

c. Analysis and Findings

The Department has previously stated that pricing transmission service based on a customer's use at the time of system peak rather than based on the customer's peak, which may not coincide with the system peak, provides a more equitable assignment of cost responsibility. D.P.U. 17-05-B at 212; D.P.U. 10-70-B at 6. The 12 CP billing for Rate T-5 is one method of efficiently assigning accurate costs to those customers who utilize the transmission system during peak periods. While customer behavior benefits from 12 CP may not result in lower system costs immediately, lower system peak usage will eventually be reflected in transmission system peak forecasts, lowering costs for all customers.

In the Company's last base distribution rate case, the Department directed the Company to evaluate the further expansion of coincident peak transmission billing to NSTAR Electric customers; however, the Company did not undertake any such evaluation that could assist the Department in weighing the merits of the proposed use of 12 CP transmission billing for all large customers (Tr. 8, at 922-924). D.P.U. 17-05-B at 213. As the Company has made and continues to make efforts toward rate alignment, and as 12 CP billing supports numerous rate-making goals such as simplicity and efficiency, the Department finds that it is reasonable and appropriate for the Company to expand optional 12 CP transmission billing to all large general service customers.

The Department recognizes that, in the immediate future, there may be administrative challenges associated with the Company's ability to implement 12 CP transmission billing using its current billing system (Exhs. ES-RDC-Rebuttal-1, at 14; UMass 1-9; UMass 1-11; Tr. 8, at 833-835). Further, the Department acknowledges that not all customers have the appropriate information to evaluate and decide whether 12 CP transmission billing is a beneficial option. Based on these considerations, we find that it is prudent for the Company to implement 12 CP billing for transmission service on an opt-in basis for large general service customers, effective January 1, 2023. Further, the Company estimates an average cost of $500 to produce a single Rate T-5 bill each month under its current billing system (Exh. DPU 58-6; Tr. 8, at 946; RR-DPU-35). We find it reasonable for the Company to assess a $500 bill preparation fee for customers who choose to opt in to 12 CP transmission service; the $500 fee will not apply to a customer that does not elect this service. The overall $500 fee shall remain in place until the Company has transitioned to its new billing system at the end of 2024 (Exh. UMass 1-11).[205]

Finally, with respect Rate G-1 demand customers, we find that it is appropriate for the Company to bill those customers a demand charge for transmission service rather than a volumetric charge. The existence of both a demand and non-demand charge inherently recognizes that different customers utilize the electric system differently. For customers where a demand charge for distribution service is preferable, and more accurately reflects the costs to serve such customers, it follows that transmission charges should be demand based as well. As such, the Department directs the Company to develop demand-based transmission charges for the Rate G-1 demand classes effective January 1, 2023.

6. Reconciling Rate Allocation Factors

a. Introduction

The Company proposes to condense the number of distribution revenue allocators ("DRA") and labor allocators, by calculating rate group values rather than rate class values (Exhs. ES-RDC-1, at 25; ES-RDC-2, Sch. 4, at 1 (Rev. 3)). The proposed rate groups are the same as those proposed for base distribution rate allocation except for small general service and streetlights forming a single group (Exh. ES-RDC-1, at 25). The DRA is a

205 During evidentiary hearings, the Company noted that it as prepares to issue a request for proposals ("RFP") relative to its new billing system, it would be a "good opportunity" to evaluate the propriety of including automated 12 CP transmission service billing into system (Tr. 8, at 836). As such, we expect the Company to include this function as part of the RFP.

function of the proposed distribution revenue targets, and the labor allocator is developed in the ACOSS (Exh. ES-RDC-1, at 25).

The Company proposes to use these updated allocators to derive rate group target revenues for reconciling rates, by aggregating total revenue required for each reconciling rate and then assigning the appropriate allocator to each group to derive the total revenue target for each reconciling rate (Exhs. ES-RDC-1, at 25; ES-RDC-2, Sch. 5, at 1 (Rev. 3)). Next, the Company divides each group's target revenue by each group's test year kWh sales to derive a unit rate for each group for each reconciling factor (Exh. ES-RDC-2, Sch. 5, at 1 (Rev. 3)).

The proposed values are:

Rate Group	**Distribution Revenue Allocator**	**Labor Allocator**
Residential Service	52.254%	54.323%
Small General Service/Streetlights	20.282%	20.748%
Medium General Service	16.658%	14.836%
Large General Service	10.806%	10.092%

Exh. ES-RDC-2, Sch. 4, at 1 (Rev. 3). No other party addressed this issue on brief.

b. Analysis and Findings

The Company's proposed use of the rate group approach to calculate the DRA and labor allocator calculations is consistent with the Company's proposed alignment efforts in distribution and transmission rates. We find that the shift to rate group allocators for reconciling rates and the use of single values for all rate classes within a group for reconciling rates, are consistent with the rate design goals of efficiency, simplicity, and fairness. Accordingly, the Department approves the move to rate group allocators and the use of those allocation factors to calculate the applicable reconciling rates. The Company in its compliance filing shall revise its tariff accordingly to implement the approved changes to the DRA and labor allocators.

C. Energy Efficiency Surcharge and Low-Income Discount

1. Introduction

On December 10, 2020, the Department opened an investigation to revise its Energy Efficiency Guidelines ("EE Guidelines") to incorporate changes in laws and Department policies and experience gained concerning energy efficiency. Updating Energy Efficiency Guidelines, Order Opening Investigation, D.P.U 20-150 (December 10, 2020).[206] In that Order, the Department presented proposed revisions to the EE Guidelines ("Revised EE Guidelines"),[207] with seven categories of revisions. D.P.U. 20-150, at 2-3. In particular, the Department proposed to update EE Guidelines, § 3.2.1.6 with a revised annual electric energy efficiency surcharge ("EES") calculation to better align the electric and gas EES calculations and to account for Department directives in Cost Based Rate Design,

[206] The Department first established its EE 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 EE Guidelines. Updating Energy Efficiency Guidelines, D.P.U. 11-120-A (2013).

[207] The proposed Revised EE Guidelines were set forth in Appendix A to D.P.U. 20-150.

D.P.U. 12-126A through 12-126I at 23 (2013). D.P.U. 20-150, at 3, 13-14; Appendix A at 5-7.

The revised EES calculation would allocate low-income energy efficiency program costs between a single residential and low-income sector and the C&I sector using a DRA and collecting 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 12-126I at 23. This change would result in two surcharges, one for the residential sector, including low-income, and one for the C&I sector, which is the same structure as the gas EES. D.P.U. 20-150, at 14. Low-income customers would continue to receive a discount on their total electric bill. D.P.U. 20-150, at 14.

In its final Order adopting the Revised EE Guidelines, the Department agreed with comments from the Low-Income Network and other stakeholders that it would be better to implement the revised EES calculation as part of a proceeding where a full analysis of the bill impacts could be performed. D.P.U. 20-150-A at 34. The Department found that, given the interaction between the current electric EES structure and the low-income discount, it was appropriate to conduct this analysis as part of a base distribution rate case proceeding. D.P.U. 20-150-A at 34-35. The Department directed each electric distribution company to submit a revised EES tariff, consistent with the Revised EE Guidelines, as part of its next base distribution rate case proceeding. D.P.U. 20-150-A at 35-36.[208]

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[208] Throughout D.P.U. 20-150-A, the Department referred to the proposed revised EE Guidelines as the Straw Proposal.

In its initial filing, the Company submitted its Energy Efficiency Charges tariff, proposed M.D.P.U. No. 50D, which was not updated pursuant to the directives in D.P.U. 20-150-A (Exh. ES-RDC-6, Sch. 1, at 250-253). Subsequently, the Company submitted a revised tariff (proposed M.D.P.U. No. 50E) to address the Department's findings and directives in D.P.U. 20-150-A (Exh. DPU 1-2, Att.). During the proceedings, the Company also agreed to increase the low-income discount from 36 percent to 42 percent in order to mitigate the bill impact associated with the RPS solar carve out, the net metering recovery surcharge, and the transition to the revised EES (Exhs. DPU 39-1, Att. B (Supp. 1); LI-ES 1-4 & Att.; LI-ES 1-5; CLC-ES 7-2).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that implementing the revised EES calculation at this time will result in significant bill impacts for ratepayers (Attorney General Brief at 17, citing Exh. DPU 39-1, Att. (c) (Supp. 2)). As such, the Attorney General asserts that the Department should delay the implementation of the revised EES calculation until the 2025-2027 three-year energy efficiency cycle to alleviate cost pressure on ratepayers (Attorney General Brief at 178-179). She also notes that delaying the implementation of the revised calculation would obviate the need to increase the low-income discount to 42 percent (Attorney General Brief at 179).

The Attorney General also submits that by delaying the implementation of the revised EES calculation for several years, it is likely that National Grid (electric) and Unitil (electric) would have filed base distribution rate cases that would allow for the required EES-related tariff changes and implementation of the associated changes for those companies (Attorney General Brief at 179). The Attorney General also contends that this delay would allow for additional time to develop policies for the best long-term approach to low-income assistance in light of current economic uncertainties in the greater context of the Commonwealth's priorities for equity and affordability as the state transitions to a clean energy future (Attorney General Brief at 179).

b. DOER

DOER argues that implementation of the revised EES calculation will compound the effect of the Company's proposed increase in base distribution rates and cost increases external to the rate-making process (DOER Reply Brief at 6-7). DOER agrees with the Attorney General that implementation should be delayed until the 2025-2027 three-year energy efficiency cycle to allow for consistency in implementation for all EDCs (DOER Reply Brief at 7).

c. Low-Income Network

The Low-Income Network argues that the Department should not implement a new EES calculation at any time, and instead should retain the old calculation (Low-Income Network Brief at 1). The Low-Income Network points to significant bill increases for low-income customers if the new calculation is implemented (Low-Income Network Brief at 2-3, citing Exh. DPU 39-1, Att. (c) (Supp. 2)). The Low-Income Network contends that these bill impacts, combined with the "worldwide energy crisis", would adversely impact low-income customers (Low-Income Network Brief at 23). Thus, the Low-Income Network asserts that the Department should "withdraw" any proposed increase to the EES (Low-Income Network Brief at 2).

d. Cape Light Compact

Cape Light Compact also argues that implementation of the Company's revised EES calculation will have significant bill impacts on ratepayers (CLC Brief at 37, citing Exh. DPU 39-1 (Supp. 2)). Further, Cape Light Compact contends that the Company's low-income ratepayers should not be subject to higher rates any sooner than low-income customers of National Grid (electric) and Unitil (electric) (CLC Brief at 37). As such, Cape Light Compact asserts that the Department should delay the implementation of the revised EES calculation until it can be done consistently across all EDCs (CLC Brief at 3, 37). In this regard, Cape Light Compact agrees with the Attorney General's timeline for implementation (CLC Reply Brief 15-16). Further, Cape Light Compact asserts that the Department should consider the impact on moderate income ratepayers in any investigation into a long-term approach to low-income assistance (CLC Reply Brief at 16).

3. Analysis and Findings

As an initial matter, the Department has reviewed the Company's proposed Energy Efficiency Charges tariff (proposed M.D.P.U. No. 50E) filed in response to information request DPU 1-2. 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 EES calculation therein allocates low-income energy efficiency program costs between a single residential and low-income combined sector and the C&I sector using a DRA and collects the resulting allocation from each rate class in the sector using a volumetric charge (Exh. DPU 1-2, Att. at 1-3). D.P.U. 20-150-A at 34; D.P.U. 20-150, at 14, citing D.P.U. 12-126A through 12-126I at 23. We affirm that this EES calculation is reasonable. The Department conditionally approves the Company's proposed Energy Efficiency Charges tariff subject to the Company's providing a clean tariff as part of its compliance filing in this case.

Regarding the implementation of the revised EES calculation, the Department directs the Company to calculate a new EES, consistent with the formula presented in proposed M.D.P.U. No. 50E, for effect on July 1, 2023, as part of its next Energy Efficiency Reconciliation Factor ("EERF") filing.[209] The Department Order adopting the Revised EE Guidelines contemplated that each company would provide a revised EES calculation in its next base distribution rate case. D.P.U. 20-150-A at 34-35. Thus, we are not persuaded that the Department should wait until National Grid (electric) and Unitil (electric) have submitted their respective revised EES calculations to begin NSTAR Electric's implementation of the revised calculation. Nor will we revisit our decision to allow for the revised EES calculation, as suggested by the Low-Income Network. The Department, however, continues to share the Low-Income Network's concerns regarding the overall affordability of energy bills, as discussed below. Further, we find that the continuing discussion and development of policies to address low-income assistance are not dependent

209 The Cape Light Compact should also recalculate its EERFs based on the revised EES for July 1, 2023.

upon the Company's delaying the implementation of the revised EES calculation. The Department and relevant stakeholders will continue to examine these issues as appropriate in future dockets.

In light of the potential bill impacts resulting from changing the EES calculation and the adjustment to the low-income discount that reflects costs associated with the RPS solar carve out and the net metering recovery surcharge for low-income customers consistent with G.L. c. 164, § 141,[210] the Company agreed to increase the low-income discount from 36 percent to 42 percent (Exhs. DPU 39-1 & Atts. (Supp. 2); LI-ES 1-4 & Att.; LI-ES 1-5; CLC-ES 7-2). The Department finds that this increase in the discount rate is reasonable and approves the proposal. As low-income customers will continue to receive a discount on their total electric bill following implementation of the revised EES calculation, the increase in the discount to 42 percent will help to mitigate the actual impacts from the revised EES calculation, once implemented in the next EERF filing. Further, the Department notes that the implementation of the 42-percent low-income discount rate effective January 1, 2023, will help mitigate winter energy prices for low-income customers, prior to the implementation of

[210] Section 141 provides that in all decisions or actions regarding rate designs, the Department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. 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. The Department notes that Section 141 was amended after evidentiary hearings in this proceeding and, therefore, the Department will not consider the revised language in this proceeding. 2022 Clean Energy Act, § 56. Nevertheless, the amended Section 141 would not have changed the Department's analysis.

the revised EES. Thus, the Department is satisfied that the revised EES calculation should be implemented consistent with the directive above.

The Department recognizes that the revised low-income discount rate constitutes a significant bill discount for low-income customers, and we are mindful of the impacts that increasing the discount rate may have for other customers. Costs associated with providing a low-income discount are recovered from all distribution customers. Accordingly, the Department balances the impact of increasing the discount rate against the impact on other customers, particularly moderate-income residential and small C&I customers. While the Department finds that the revision to the EES, which will result in a EERF reduction for non-low-income residential customers, and the adjustment to the low-income discount are reasonable at this time, the Department notes that adjustments to the low-income discount and framework may be required in the future to provide equity for all customers. The low-income discount rate was historically fixed at 25 percent. Pursuant to G.L. c. 164, § 141, the low-income discount rate has increased in recent years to provide a full offset of DG resources that have, to date, not been as widely adopted by low-income customers.[211] As the low-income discount rate increases, the delta between moderate-income

[211] Recent changes in law and incentive programs, such as SMART and energy efficiency programs, seek to change the landscape of low-income solar adoption. See, e.g., 2021 Climate Act, §§ 54, 94; 2022 Clean Energy Act, §§ 24, 87A (each section establishing new solar incentive requirements or programs for low-income customers). As low-income participation increases, the Department may revisit the appropriate level of costs that should be offset by a low-income discount pursuant to G.L. c. 164, § 141.

and low-income customer energy costs has become significant. For future base distribution rate cases, EDCs should 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.

The Department recognizes that energy bills have strained many family budgets, and we have learned from the COVID-19 pandemic and our experience with arrearage management that there is a need for a deeper understanding of the impact energy costs are having on households. Further, with the upcoming electric supply issues, ensuring a more in-depth understanding of energy burdens has become essential. To begin collecting more detailed and utility-specific information on energy burden, the Department directs NSTAR Electric to make detailed utility burden index analysis on electricity residential bills in their Annual Returns to the Department, beginning with the 2022 Annual Return submitted in Spring 2023.

With this directive, the Company must establish a credible process for tracking and calculating customers' energy burdens with the intention of using this information to develop more advanced and meaningful strategies to enhance customer engagement and support. The Department expects that the Company will provide a detailed household economic burden index analysis evaluating residential energy electric utility customer bills as percentages of household income by county and to provide the summary results of a detailed household burden index analysis by, at least census, block group. An electric customer's total bill should include net metering from solar, low-income discounts, and other factors impacting the bill. Additionally, the Company shall show the analysis by household income for the statewide median household income and 50 percent, 100 percent, and 200 percent of the Federal Poverty Guidelines. This level of granularity in the data is intended to provide a clearer picture of specific areas of the Company's service territory with higher-than-average energy burden. The Department recognizes that for the beginning of this process, we are primarily focused on electric utility bills generated by EDCs. Therefore, the Department will issue directives to National Grid (electric) and Unitil (electric) to include in their 2022 Annual Returns to the Department similar analyses as discussed above. As more homes convert to electric heat, the Department may consider requiring an analysis of energy burden between heating and non-heating customers.

D. 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. 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 EROR. 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. 17-05-B at 261. Nonetheless, the Department must balance its goal of fairness with its goal of continuity.

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.

2. Rate Design Overview

The basic components of the Company's delivery service rates are the customer charge, which is a fixed monthly amount, and the distribution charge (Exh. ES-RDC-1, at 7). The distribution charge includes an energy (kWh) charge based on usage, and, for some C&I customers, can also include a demand (kW) charge (Exh. ES-RDC-1, at 7). The customer charge is intended to recover fixed costs that do not vary with customer electricity use, such as the costs of billing and metering (Exh. ES-RDC-1, at 7). Energy charges are a function of customer use, and, therefore, impact a customer's bill in proportion to how much electricity a customer has consumed in a given month (Exh. ES-RDC-1, at 7). A demand charge may be a per-kW charge or per-kilovolt-ampere ("kVA") charge that is billed on the customer's highest usage at a single point in time (Exh. ES-RDC-1, at 7).

Since fixed charges (i.e., customer charges) remain the same irrespective of usage, increases to fixed charges can have a negative bill impact on customers with low usage (Exh. ES-RDC-1, at 8). This impact may produce a high percentage bill impact, but not necessarily a large total dollar bill impact (Exh. ES-RDC-1, at 8). Conversely, higher customer charges benefit high volume users because a higher customer charge means a lower volumetric charge to recover the class revenue requirement, and, as such, fewer dollars need to be collected on a volumetric basis (Exh. ES-RDC-1, at 8). In addition, lower customer charges and higher volumetric rates may send price signals aligned with the Commonwealth's public policy objectives regarding on-site generation and energy efficiency. G.L. c. 164, § 141. Establishing the proper customer charge is a trade-off where the intra-class subsidization of costs between high- and low-consumption customers needs to be balanced against the customer bill impacts, as well as the relevant policy objectives under G.L. c. 164, § 141 (Exh. ES-RDC-1, at 8).

3. Residential Rates

a. Introduction

In D.P.U. 17-05-B at 89-92, the Department approved the consolidation of residential rates for all four legacy companies. Therefore, the Company has four residential rate classes offered across its EMA and WMA service areas: Rate R-1 is the residential non-heating rate class; Rate R-2 is the residential non-heating assistance rate class; Rate R-3 is the residential space heating rate class; and Rate R-4 is the residential space heating assistance rate class (Exhs. ES-RDC-1, at 16; ES-RDC-6, Sch. 1, at 8).

b. Company Proposal

i. Residential Rate R-1 and Residential Rate R-2

The Company's current residential Rate R-1 is available for all domestic purposes in individual private dwellings, individual apartments, or residential condominiums in which the principal means of heating the premises is not provided by permanently installed electric space heating equipment (Exh. ES-RDC-6, Sch. 2, at 53). The Company's current residential Rate R-2 is available to any Rate R-1 customer that is eligible for the Low-Income Home Energy Assistance Program ("LIHEAP"), or its successor program, or receives any means-tested public benefit for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. ES-RDC-6, Sch. 2, at 55-57). Currently residential Rate R-1 and R-2 customers have a customer charge of $7.00 per month and an energy charge of $0.05165 per kWh (Exh. ES-RDC-2, Sch. 11, at 1 (Rev. 3)). The Company proposes to increase the monthly customer charge to $10.00 per month, and energy charge to $0.06107 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

ii. Residential Rate R-3 and Residential Rate R-4

The Company's current residential Rate R-3 is available for all domestic uses in a single private dwelling, in an individual apartment, or in a residential condominium where the principal means of heating the premises is provided by permanently installed electric space heating equipment (Exh. ES-RDC-6, Sch. 2, at 58). The Company's current residential Rate R-4 is available to any Rate R-3 customer that is eligible for LIHEAP, or its successor program, or receives any means-tested public benefit for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. ES-RDC-6, Sch. 2, at 60, 62). Currently Rate R-3 and R-4 customers have a customer charge of $7.00 per month and an energy charge of $0.04494 per kWh (Exh. ES-RDC-2, Sch. 11, at 2 (Rev. 3)). The Company proposes to increase the monthly customer charge to $10.00 per month, and the distribution energy charge to $0.05679 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

c. Positions of the Parties

i. Attorney General

The Attorney General argues that the Department should reject the Company's proposed residential customer charge (Attorney General Brief at 166). According to the Attorney General, the proposed increase of $3.00, or 43 percent, from $7.00 to $10.00, is inconsistent with promoting energy efficiency because it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts (Attorney General Brief at 166). In addition, the Attorney General contends that an increase in the residential customer charge is not necessary, as the Company already collects a significant portion of its fixed costs through the current customer charge (Attorney General Brief at 168). Finally, the Attorney General asserts that the proposed increase in residential customer charges will have a disproportionately adverse impact on low-income ratepayers and fixed-income ratepayers, creating equity concerns (Attorney General Brief at 169).

ii. DOER

DOER argues that the proposed increase in the customer charge is not necessary for the Company's revenue stability and would cause rate shocks for consumers if the energy charge is not also reduced, especially considering other price increases across the economy (DOER Brief at 18). Further, DOER contends that if revenue decoupling is eliminated in the future, the method by which the Company will recover costs will change, and an increase in volumetric sales could lead to a decreased need to collect fixed costs (DOER Brief at 19).

iii. Cape Light Compact

Cape Light Compact argues that the Company's proposed increase in the residential customer charge is significant and should be rejected (CLC Brief at 28). In particular, Cape Light Compact asserts that the impact of the proposed increase would be difficult for those on a fixed income and who are low-income or low-use customers with little load to shift (CLC Brief at 28-31, citing Exh. CLC-JDW-1, at 5). Cape Light Compact recommends that the Company phase in the increase by $1.00 per year over a three-year period to achieve greater stability for customers (CLC Brief at 31-32, citing Exh. CLC-KFG-1, at 11, Table 3). Cape Light Compact asserts that the deficiency in revenue from this phased-in approach could be recovered through the residential energy charge (CLC Brief at 32).

iv. Company

The Company argues that the proposed residential customer charge increases are necessary because current charges are below the embedded cost levels that represent the customer cost to serve or are required to align classes more closely in the various legacy service areas (Company Brief at 426, citing Exh. CLF-1-4). Further, the Company contends that customer charges have barely increased since 1998 despite the addition of other rates that have made the customer charge an increasingly minor part of the total customer bill (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5). In addition, the Company asserts that the proposed $10.00 customer charge represents only seven percent of the total bill for an average customer, while the current customer charge of $7.00 represents five percent of the total bill for an average customer (Company Brief at 426, citing

Exh. ES-RDC-Rebuttal-1, at 5). According to the Company, this comparison demonstrates that more than 90 percent of an average customer bill is volumetric under both proposed and current rates (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5). Thus, the Company asserts that it does not recover most of its fixed customer-related costs outside of customer volumetric charges and average customers will continue to have the ability to reduce a vast portion of their bill (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5). The Company contends that the proposed customer charge is not a dramatic increase and will not impede conservation, but it will improve efficiency by more properly assigning fixed costs to fixed charges (Company Brief at 426, citing Exh. ES-RDC-Rebuttal-1, at 5).

Further, the Company argues that its proposed increase to the residential customer charge is intended to send the correct price signal to customers and to stabilize customer costs and is not intended to maintain revenue stability for the Company (Company Brief at 427, citing Exh. ES-RDC-Rebuttal-1, at 5). Moreover, the Company contends that the increased customer charge to low-income customers will be mitigated by the proposed increase in the low-income discount to 42 percent from 36 percent (Company Brief at 427, citing Exhs. LI-ES 1-4; LI-ES 1-5; CLC-ES 5-1; CLC-ES 7-2). Finally, the Company asserts that the rate burden to lower-use customers is not increased significantly more than for higher-use customers because, as noted above, more than 90 percent of an average customer bill is volumetric under both proposed and current rates (Company Brief at 427, citing Exhs. LI-ES 1-4; LI-ES 1-5; CLC-ES 5-1; CLC-ES 7-2).

d. Analysis and Findings

In recent years, the Department has frequently required companies to set demand and energy volumetric rates based on the revenue requirement remaining after revenues from the proposed customer charges have been taken into consideration. See, e.g., D.P.U. 18-150, at 542-562; D.P.U. 17-05-B at 260-323. The Department is charged with reviewing the resulting rates that the customer will experience, as well as the associated bill impact from changes to those rates, requiring us to weigh the goals of fairness, efficiency, simplicity, stability, and continuity. D.P.U. 18-150, at 543; D.P.U. 17-05-B at 260. As discussed in numerous places in this Order, the Department considers multiple factors in making its decisions regarding allowable costs, the resulting change in rates, and the resulting customer bills. There is no single optimal method of setting rates that will impact all customers equally. 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 that fixed charge than a customer with high usage. 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.

The Company has demonstrated that its customer charges represent a relatively small amount of the total bill and, as such, the proposed increases will still provide appropriate price signals to customers to encourage implementation of conservation measures to lower their overall bill (Exh. ES-RDC-Rebuttal-1, at 5). Further, as noted in Section XVII.C.3

above, the Department approved an increase in the low-income discount rate from 36 percent to 42 percent. We find that the increase in the low-income discount rate will assist in mitigating the bill impacts to low-income customers of any rate increase. Based on these considerations, we are not persuaded that a phase-in of the proposed increase to the customer charge is warranted.

According to the Company's ACOSS, the existing embedded customer charge for rate classes R-1 and R-2 is $10.73 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for rate classes R-1 and R-2 best meets our rate design goals and objectives. Therefore, the Department approves a monthly customer charge of $10.00 for rate classes R-1 and R-2. The Company shall set the volumetric rate for rate classes R-1 and R-2 to recover the remaining class distribution revenue requirement approved in this Order.[212]

According to the Company's ACOSS, the existing embedded customer charge for rate classes R-3 and R-4 is $13.10 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $10.00 for rate classes R-3 and R-4 best meets our rate design goals and objectives. Therefore, the Department approves a monthly customer charge of

[212] The Department also directs NSTAR Electric, when designing the rates for the individual rate classes, to truncate the variable per kWh charges after five decimal places and truncate the variable per kW demand charges after two decimal places so that rates are designed to collect no more than the allowed revenue requirement.

$10.00 for rate classes R-3 and R-4. The Company shall set the volumetric rate for rate classes R-3 and R-4 to recover the remaining class distribution revenue requirement approved in this Order.

4. Small General Service Rates

a. Introduction

As discussed in Section XVII.B.3.b above, the Department approved the Company's proposal to group customers with less than 100 kW of demand annually into a small general service rate group. In doing so, some customers currently served on certain rate classes moved to different rate classes to allow for this alignment, and the Department allowed the Company's proposal to cancel multiple rate classes. Further, as discussed in Section XVII.B.3.b above, the Department allowed the Company's proposal to eliminate seasonal rate offerings (except for Rate T-1), to eliminate the energy block rate design and some demand ratchets where currently used, and to introduce a non-demand rate pricing option for proposed Rate G-1 (Exh. ES-RDC-1, at 41).[213]

b. Boston Edison Service Area

i. Company Proposal

(A) Rate G-1 Demand and Non-Demand

NSTAR Electric proposes Rate G-1 to be available for all non-residential uses of electricity to all customers in the Boston Edison service area where the service voltage is less

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213 In their next respective base distribution rate proceeding, the EDCs shall examine rate designs for all electric buildings to align with the Commonwealth's electrification policies.

than 14,000 volts and the load for billing purposes does not exceed or is estimated not to exceed 100 kW for twelve consecutive months (Exh. ES-RDC-6, Sch. 1, at 136). This offering will consist of two pricing options: (1) a non-demand pricing option, as currently exists for Rate G-1, and (2) a demand pricing option (Exhs. ES-RDC-1, at 44-45; ES-RDC-6, Sch. 1, at 136). The Company proposes that demand meters be installed for all new customers regardless of their elected price option but will assign new customers to the non-demand price option unless otherwise requested (Exh. ES-RDC-6, Sch. 1, at 136). Customers with demand that does not exceed 10 kW for twelve consecutive months may not elect the demand price option (Exh. ES-RDC-6, Sch. 1, at 136).

Currently, Rate G-1 non-demand customers have a monthly customer charge of $8.00, and summer and winter energy charges of $0.08267 per kWh and $0.05133 per kWh, respectively (Exh. ES-RDC-2, Sch. 12, at 1 (Rev. 3)). The Company proposes a monthly customer charge of $15.00 for the non-demand offering and an energy charge of $0.04874 for both summer and winter (Exh. ES-RDC-2, Sch. 12, at 1 (Rev. 3)).

Currently, Rate G-1 demand customers have a monthly customer charge of $11.00, summer and winter demand charges for customers with greater than 10 kW annual use of $0.97 per kW and $0.31 per kW, respectively, and declining block rate pricing for energy ranging from $0.02899 per kWh to $0.07679 per kWh for summer, and $0.02758 per kWh to $0.04778 per kWh for winter (Exh. ES-RDC-2, Sch. 12, at 1 (Rev. 3)). The Company proposes a monthly customer charge of $20.00 for the demand offering and a demand charge of $18.25 (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

As noted in Section XVII.B.3.b above, to align small C&I customers across the legacy companies, the Department allowed the Company's proposed transfer of some customers currently taking service under Rate G-2 and Rate T-2 to the newly introduced demand pricing option under Rate G-1. Further, the Department approved the Company's proposal to cancel current Rate G-2, given the alignment in definitions for small and medium rate classes. Current Rate G-2 customers have a customer charge of $18.00 per month, and a distribution demand charge for those using more than 10 kW annually of $22.90 per kW in the summer and $10.68 per kW in the winter (Exh. ES-RDC-2, Sch. 12, at 2-3 (Rev. 3)). Current Rate T-2 customers have monthly inclining block customer charges ranging from $27.00 to $360.00, summer demand charges of $22.21 per kW, and winter demand charges of $12.66 per kW (Exh. ES-RDC-2, Sch. 12, at 3 (Rev. 3)).

(B) Rate T-1 (Closed)

Rate T-1 is an optional TOU rate that is closed to new customers (Exh. ES-RDC-1, at 46). The rate is available for non-residential customers in the Boston Edison service area who take their electric service through a single meter, subject to the availability of TOU meters as determined by the Company (Exh. ES-RDC-6, Sch. 1, at 143). This rate is not available when a customer's load for billing purposes either exceeds or is estimated to exceed 10 kW in any billing month (Exh. ES-RDC-6, Sch. 1, at 143). This rate is used primarily by customers with standalone net metering facilities (Exh. ES-RDC-1, at 71).

Currently, Rate T-1 customers have a monthly customer charge of $10.00 and an energy charge of $0.17851 per kWh during the summer peak period[214] and $0.02353 per kWh during the summer off-peak period[215] (Exh. ES-RDC-2, Sch. 12, at 2 (Rev. 3)). Rate T-1 customers also have energy charges of $0.08369 per kWh and $0.02133 per kWh for the winter peak hours period and off-peak hours period, respectively (Exh. ES-RDC-2, Sch. 12, at 2 (Rev. 3)). The Company proposes to increase the monthly customer charge to $20.00 but make no changes to the current energy rates (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-1 and Rate T-1 is $11.39 per month (Exh. ES-ACOS-2, at 9, (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $15.00 for the Rate G-1 non-demand offering best meets our rate design goals and objectives. Similarly, the Department finds that a monthly customer charge of $20.00 and demand charge of $18.25 per kW for the Rate G-1 demand

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214 For Boston Edison Rate T-1, the Company defines the peak period as the hours between 9:00 a.m. and 6:00 p.m. on weekdays during the months of June through September and the hours between 8:00 a.m. and 9:00 p.m. during the months of October through May, when the peak period is the hours between 8 a.m. and 9 p.m. weekdays (Exh. ES-RDC-6, Sch. 2, at 77).

215 For Boston Edison Rate T-1, the Company defines off-peak hours as those that are not peak hours, including all hours during twelve Massachusetts holidays (Exh. ES-RDC-6, Sch. 2, at 77-78).

offering meets our rate design goals and objectives. Therefore, the Department approves (a) a monthly customer charge of $15.00 for the Rate G-1 non-demand offering and (b) a monthly customer charge of $20.00 for the Rate G-1 demand offering. The Company shall set a single volumetric rate for Rates G-1 demand and non-demand options. For Rate T-1, the Department finds a monthly charge of $20.00 to be appropriate and consistent with our rate design goals and objectives, therefore, we approve it. The Company shall set volumetric rates to recover the remaining class distribution revenue requirements approved in this Order, keeping the energy charges for the peak and off-peak hours and for the summer and winter periods in proportion with current rates. Further, the Department accepts the cancellation of current Rate G-2, given the proposed common definition of a small general service customer.

c. Cambridge Electric Light Service Area

i. Company Proposal

(A) Rate G-1

In Section XVII.B.3.b above, the Department allowed the Company's proposed realignment and consolidation of Cambridge Electric Light Rate G-1 to serve current Rate G-0, Rate G-1, and Rate G-4 customers (Exh. ES-RDC-1, at 20).[216] Cambridge Electric Light Rate G-1 will be available for all non-residential uses of electricity to all customers in the Cambridge Electric Light service area where the service voltage is less than 13,800 volts and demand does not exceed or is estimated not to exceed 100 kW in each of

[216] In addition, the Department allowed the Company's proposal to cancel Rate G-0 and Rate G-4 (Exhs. ES-RDC-1, at 20; ES-RDC-6, Sch. 1, at 152, 162).

twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 153). Current Rate G-0 has a customer charge of $5.00 and an energy charge of $0.03870 per kWh (Exh. ES-RDC-2, Sch. 12, at 4 (Rev. 3)). Current Rate G-1 has a customer charge of $8.00 and demand charges of $4.28 per kW for customers using 10 kW or less, and $7.98 for customers using more than 10 kW, as well as an energy charge of $0.01288 per kWh (Exh. ES-RDC-2, Sch. 12, at 4 (Rev. 3)). Current Rate G-4 has a customer charge of $12.00 per month and a demand charge of $4.74 per kW and an energy charge of $0.01188 per kWh (Exh. ES-RDC-2, Sch. 12, at 5 (Rev. 3)).

For proposed Rate G-1, the Company proposes a monthly customer charge of $15.00, no demand charge, and an energy charge of $0.03448 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(B) Rate G-5 (Closed)

Cambridge Electric Light Rate G-5 is proposed to be available only at existing service locations to customers in the Cambridge Electric Light service area who were taking service under this rate prior to December 1, 1985, for electric space heating through a separate meter where electricity is the sole means of heating the premises (Exh. ES-RDC-6, Sch. 1, at 163). Currently, customers taking service on Rate G-5 have a customer charge of $8.00 per month, as well as energy charges of $0.02024 per kWh for energy use equal to or less than 5,000 kWh, and $0.02659 per kWh for customers using more than 5,000 kWh per month (Exh. ES-RDC-2, Sch. 12, at 5 (Rev. 3)). The Company proposes to increase the customer charge to $15.00 per month and proposes an energy charge for all levels of use of $0.02527 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(C) Rate G-6 (Closed)

Cambridge Electric Light Rate G-6 is an optional TOU rate that is closed and used by standalone net metering customers (Exh. ES-RDC-1, at 47). The rate is available upon written application and the execution of an electric service agreement, for non-residential customers in the Cambridge Electric Light service area who take their electric service through a single meter, subject to the availability of TOU as determined by the Company (Exh. ES-RDC-6, Sch. 1, at 165). This rate is not available when a customer's load for billing purposes either exceeds or is estimated to exceed 10 kW in any three consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 165). The current monthly customer charge for Rate G-6 is $9.00, and the energy charges for the peak load period ("peak use")[217] is $0.06346 per kWh, and for the low load period ("low load use")[218] is $0.02338 per kWh (Exh. ES-RDC-2, Sch. 12, at 4 (Rev. 3)). The Company proposes to increase the customer

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217 For purposes of Cambridge Electric Light Rate G-6, the Company defines the peak load period as that portion of the year when eastern daylight savings time is in effect, the period beginning at 9:00 a.m. and ending at 6:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 110). When eastern standard time is in effect, the peak load period is the period beginning at 4:00 p.m. and ending at 9:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 110).

218 For purposes of Cambridge Electric Light Rate G-6, the Company defines the low load period as all hours not included in the peak load period (Exh. ES-RDC-6, Sch. 2, at 110).

charge to $20.00 per month but proposes no changes to the current volumetric charges (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-1, Rate G-4, and Rate G-6 is $23.03 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). The embedded customer charge for proposed Rate G-5 is $33.88 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of $15.00 for Rate G-1 and Rate G-5 best meet our rate design goals and objectives. Therefore, the Department approves (a) a monthly customer charge of $15.00 for Rate G-1 and (b) a monthly customer charge of $15.00 for Rate G-5. For Rate G-1, the Company shall eliminate the current demand charge and recover the remaining class distribution revenue requirements approved in this Order using a single volumetric rate. For Rate G-5 the Company shall also implement a single volumetric rate to recover the remaining class distribution revenue requirements approved in this Order. In addition, for Rate G-6 the Department finds that a monthly customer charge of $20.00 also meets our rate design goals and objectives and, therefore, we approve it. For Rate G-6, the Company shall recover the remaining class distribution revenue requirements approved in this Order through the energy charges using the proposed method for establishing these rates.

d. Commonwealth Electric Service Area

i. Company Proposal

(A) Rate G-1

Commonwealth Electric Rate G-1 is proposed to be available to all customers in the South Shore, Cape Cod, and Martha's Vineyard service area except those customers whose load for billing purposes either exceeds or is estimated to exceed 100 kW in each of twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 183). The Company states that demand meters will be installed for all new customers (Exh. ES-RDC-6, Sch. 1, at 183). Commonwealth Electric Rate G-1 is proposed to serve customers currently taking service under both the annual and seasonal offerings, as well as current Rate G-5 customers (Exh. ES-RDC-1, at 72).[219] These rate classes currently have a monthly customer charge of $6.00 (Exh. ES-RDC-2, Sch. 12, at 6, 8 (Rev. 3)). Customers currently taking service under this offering have a demand charge of $5.59 per kW for customers using greater than 10 kW, as well as energy charges of $0.04684 per kWh for customers with less than or equal to 2,300 kWh of use, and $0.01269 per kWh for customers with greater than 2,300 kWh of use (Exh. ES-RDC-2, Sch. 12, at 6 (Rev. 3)). Current Rate G-1 for seasonal customers has a demand charge of $4.93 per kW for customers using greater than 10 kW, as well as energy charges of $0.08697 per kWh for customers with less than or equal to

[219] In Section XVII.B.3.b above, the Department allowed the Company's consolidation and alignment plan, and, therefore, allowed the Company's proposal to cancel Rate G-5 (Exh. ES-RDC-1, at 72).

1,800 kWh of use and \$0.02763 per kWh for customers with greater than 1,800 kWh of use (Exh. ES-RDC-2, Sch. 12, at 6 (Rev. 3)).

For proposed Rate G-1, the Company proposes to eliminate the seasonal offering and the demand charge; and set the monthly customer charge at \$15.00 and energy charge at \$0.03755 per kWh for all hours of use (Exhs. ES-RDC-1, at 47; ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(B) Rates G-7

Rate G-7 is an optional TOU rate offering available for all non-residential uses of electricity to customers in the South Shore, Cape Cod and Martha's Vineyard service area except those whose load for billing purposes either exceeds or is estimated to exceed 100 kW in each of twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 201). This rate currently serves annual as well as seasonal customers (Exh. ES-RDC-6, Sch. 1, at 201). The current Rate G-7 monthly customer charge is \$10.00, and, for annual customers, the demand charge is \$3.81 per kW, the peak use[220] energy charge is \$0.02621 per kWh, and the low load use[221] energy charge is \$0.01836 per kWh (Exh. ES-RDC-2, Sch. 12, at 7 (Rev. 3)).

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220 For purposes of Commonwealth Electric Rate G-7, the Company defines the peak load period as that portion of the year when eastern daylight savings time is in effect, the period beginning at 9:00 a.m. and ending at 6:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 110). When eastern standard time is in effect, the peak load period is the period beginning at 4:00 p.m. and ending at 9:00 p.m. on all weekdays, Monday through Friday (Exh. ES-RDC-6, Sch. 2, at 164).

221 For purposes of Commonwealth Electric Rate G-7, the Company defines the low load period as all hours not included in the peak load period (Exh. ES-RDC-6, Sch. 2, at 164).

For current seasonal customers, the demand charge is $3.86 per kW, the peak use energy charge is $0.05113 per kWh, and the low load use energy charge is $0.04300 per kWh (Exh. ES-RDC-2, Sch. 12, at 7 (Rev. 3)).

The Company proposes to eliminate the seasonal offering and set the monthly customer charge at $20.00, the demand charge at $3.81 per kW, the peak use energy charge at $0.03747 per kWh, and the low load use energy charge at $0.02625 per kWh (Exhs. ES-RDC-1, at 47-48; ES-RDC-2, Sch. 1, at 1 (Rev. 3)). Furthermore, the Department allowed the Company's proposal to close Rate G-7 to curb the growth of discounted legacy rates and to facilitate alignment (Exh. ES-RDC-1, at 72).

(C) Rate G-4 (Closed)

Rate G-4 is closed to new customers (Exh. ES-RDC-1, at 48). It is available for general power purposes only at existing service locations to customers in the South Shore, Cape Cod, and Martha's Vineyard service area who were taking service under this rate schedule as of February 8, 1980 (Exh. ES-RDC-6, Sch. 1, at 194). This rate is not available for standby service in idle plants or buildings, or where operations have been reduced to a small part of normal capacity of the plant (Exh. ES-RDC-6, Sch. 1, at 194). For industrial service where the connected load is 50 horsepower or more, incidental lighting is allowed (Exh. ES-RDC-6, Sch. 1, at 194). The current monthly customer charge for Rate G-4 is $6.00, the demand charge is $1.99 per kW, and the energy charge is $0.02282 per kWh (Exh. ES-RDC-2, Sch. 12, at 8 (Rev. 3)). The Company proposes a monthly customer charge of $15.00, a demand charge of $2.17 per kW, and an energy charge of $0.02490 per kWh (Exh. ES-RDC-2, Sch. 1, at 1, (Rev. 3)).

(D) Rate G-6 (Closed)

Rate G-6 is also closed to new customers (Exh. ES-RDC-1, at 48). It is available only at existing service locations to customers in the South Shore, Cape Cod, and Martha's Vineyard service area who were taking service as of February 8, 1980, under an all-electric school rate schedule or under a special contract for all-electric school service (Exh. ES-RDC-6, Sch. 1, at 198). This rate is available for annual service in public and private school buildings where electricity supplies the total energy requirements of the premises served (Exh. ES-RDC-6, Sch. 1, at 198).

The current monthly customer charge for Rate G-6 is $30.00, and the energy charge is $0.01867 per kWh. The Company proposes a monthly customer charge of $15.00 and an energy charge of $0.01974 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charges for proposed Rate G-1 and Rate G-7 is $15.32 per month, and for Rate G-5 is $16.07 per month (Exh. ES-ACOS-2, at 10-11 (Rev. 3)). For proposed Rate G-4, the embedded monthly customer charge is $35.90, and for proposed Rate G-6 the embedded monthly customer charge is $41.33 (Exh. ES-ACOS-2, at 11 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that a monthly customer charge of

$15.00 for Rate G-1, Rate G-4, and Rate G-6, as well as $20.00 for Rate G-7 best meet our rate design goals and objectives. Therefore, the Department approves (a) a monthly customer charge of $15.00 for Rate G-1, Rate G-4, and Rate G-6 and (b) a monthly customer charge of $20.00 for Rate G-7. As stated in Section XVII.B.3.b above, the Department approves the Company's proposal to eliminate the seasonal offerings under Rates G-1 and G-7. For Rate G-1, the Department also approves the Company's proposal to eliminate the demand charge as it meets the rate design goal of simplicity. Further, the Department approves the Company's proposed demand charges of $3.81 per kW for Rate G-7 customers and $2.17 per kW for customers taking service under Rate G-4 as they best meet our rate design goals and objectives at this time.

The Company shall recover the remaining distribution revenue requirement for Rate G-1 approved in this Order using a single volumetric rate. For Rate G-7, the Company shall change current peak use and low load use energy charges in proportion with current energy rates to collect the remaining distribution revenue requirement approved in this Order. For Rate G-4 and Rate G-6, the Company shall recover the remaining distribution revenue requirements approved in this Order for each class using a single volumetric rate for each rate class.

e. WMA Service Area

i. Company Proposal

(A) Rate 23 (Closed)

Rate 23 has not been available to new customers since February 1, 2011 (Exh. ES-RDC-6, Sch. 1, at 205). This rate is applicable to the use of electricity for water heating of any customer other than residential in the WMA service territory (Exh. ES-RDC-6, Sch. 1, at 205). This rate is available to residential customers where electricity supplies a portion of, but is not the sole source of, domestic hot water heating (Exh. ES-RDC-6, Sch. 1, at 205). It is also available for centrally supplied water heating in apartment buildings (Exh. ES-RDC-6, Sch. 1, at 205).

The monthly customer charge for Rate 23 is currently $17.00 and the energy charge is $0.03125 per kWh (Exh. ES-RDC-2, Sch. 12, at 9 (Rev. 3)). The Company proposes to increase the monthly customer charge to $20.00 and decrease the energy charge to $0.02356 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(B) Rate 24 (Closed)

Rate 24 is applicable to the use of electricity for lighting and incidental power in an edifice set apart exclusively for public worship and only for those customers in the WMA service territory already receiving service on this rate (Exh. ES-RDC-6, Sch. 1, at 208).

The monthly customer charge for Rate 24 is currently $65.00, the demand charge is $4.84 per kW for demand over 2 kW, and the energy charge is $0.00617 per kWh (Exh. ES-RDC-2, Sch. 12, at 9 (Rev. 3)). The Company proposes no change to the customer or demand charges and proposes to increase the energy charge to $0.00902 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)).

(C) <u>Rate G-1</u>

In Section XVII.B.3.b above, the Department allowed the Company's consolidation and alignment proposal for Rate G-1 to serve those customers currently taking service under Rate G-0, as well as Rate T-0, Rate T-4, and Rate G-2 customers using less than or equal to 100 kW of demand (Exhs. ES-RDC-1, at 72-73; ES-RDC-6, Sch. 2, at 171). Therefore, we allowed the Company's proposal to rename current Rate G-0 as Rate G-1, and to cancel Rate T-0 (Exh. ES-RDC-1, at 72). This rate is applicable to all uses of electricity at a single location in the WMA service territory that does not exceed a demand of 100 kW (Exh. ES-RDC-6, Sch. 1, at 210). The Company states that demand meters will be installed for all new customers regardless of the elected price option (Exh. ES-RDC-6, Sch. 1, at 210). Further, NSTAR Electric states that all electricity delivered under this rate shall be measured through one metering equipment, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of the amount of electricity consumed may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 210). The Company states that all electricity supplied shall be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 210). The Company further states that, with its permission, a customer may furnish electricity to persons or entities who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure or control the use of, any of the electricity furnished (Exh. ES-RDC-6, Sch. 1, at 210). Finally, the Company states that all new customers will be assigned the non-demand price option unless otherwise requested by the customer, and that unmetered customers may not elect the demand price option (Exh. ES-RDC-6, Sch. 1, at 210).

The current monthly customer charge for Rate G-0 is $30.00 for metered customers and $15.00 for unmetered customers (Exh. ES-RDC-2, Sch. 12, at 10 (Rev. 3)). The demand charge for customers with demand more than 2 kW is $10.83 per kW and the energy charge is $0.00213 per kWh (Exh. ES-RDC-2, Sch. 12, at 10 (Rev. 3)). Current Rate T-0 is a TOU rate, with a current monthly customer charge of $30.00, a demand charge of $10.50 per kW for use over 2 kW, a peak period energy charge of $0.00329 per kWh, and an off-peak period energy charge of $0.00088 per kWh (Exh. ES-RDC-2, Sch. 12, at 11 (Rev. 3)). Current Rate T-4 is also a TOU rate,[222] with a monthly customer charge of $353.00, a demand charge for customers using less than or equal to 50 kW of $1.99 per kW, a demand charge of $9.37 per kW for customers using more than 50 kW, a peak energy charge of $0.00315 per kWh, and an off-peak energy charge of $0.00089 per kWh (Exh. ES-RDC-2, Sch. 12, at 12 (Rev. 3)). Current Rate G-2 has a monthly customer charge of $353.00, a demand charge of $1.99 per kW for use equal to or less than 50 kW, a

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222 For Rate T-4 and all WMA TOU rates, the Company defines the peak period as weekdays from noon to 8 p.m., while all other hours are the off-peak period (Exh. ES-RDC-6, Sch. 2, at 178, 182, 186).

demand charge of $9.37 per kW for use over 50 kW, and an energy change of $0.00210 per kWh (Exh. ES-RDC-2, Sch. 12, at 12 (Rev. 3)).

The Company proposes the new Rate G-1 offerings to have a monthly customer charge of $30.00 for metered customers and $15.00 for unmetered customers (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). For non-demand Rate G-1 customers, the Company proposes an energy charge of $0.03614 per kWh. For demand Rate G-1 customers, the Company proposes a demand charge for customers using more than two kW of $10.83 per kW and an energy charge of $0.00434 per kWh (Exh. ES-RDC-2, Sch. 1, at 1 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded monthly customer charge for proposed Rate 23 is $20.00 and the embedded monthly customer charge for proposed Rate 24 is $50.08 (Exh. ES-ACOS-2, at 11 (Rev. 3)). For proposed Rate G-1, the embedded monthly customer charge is $26.49 per month (Exh. ES-ACOS-2, at 12 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $20.00 for Rate 23 and $65.00 for Rate 24 best meets our rate design goals and objectives and, therefore, are approved. Similarly, monthly customer charges of $30.00 for metered and $15.00 for unmetered Rate G-1 customers best meets our rate design goals and objectives and, therefore, are approved.

The Department also finds that the proposed demand charge of $4.84 per kW for Rate 24 customers using more than two kW meets our rate design goals and objectives and, therefore, is approved. Similarly, for the Rate G-1 demand offering, the Department approves the Company's proposed demand charge of $10.83 per kW for customers using more than two kW as it is equal to the current charge for customers taking service under Rate G-0, and, therefore, meets the Department's goal of continuity. Further, the Company shall set energy rates for Rate 23, Rate 24, and Rate G-1 to recover each class's remaining class distribution revenue requirements approved in this Order.

5. Medium General Service Rates

a. Introduction

As previously mentioned, in Section XVII.B.3.b the Department accepted the Company's proposal to group customers with less than 100 kW of demand annually into a small general service rate group (Exh. ES-RDC-1, at 19). In doing so, the Company moved some customers previously considered to be in the small C&I rate group into the medium C&I rate group (Exh. ES-RDC-1, at 19-20). Therefore, some customers currently served at rates previously defined as small and medium C&I will move to different rate classes to allow for this alignment (Exh. ES-RDC-1, at 19-20). Generally, the definition for the medium C&I rate group is customers with demand greater than 100 kW that are not otherwise served by a large C&I rate class (Exh. ES-RDC-1, at 20). Similar to its approach to small C&I rates, the Department allowed the Company's proposal to eliminate seasonal pricing in the Boston Edison service area and to eliminate most instances of demand block design where used (Exh. ES-RDC-1, at 50).

b. Boston Edison Service Area

i. Company Proposal

(A) Rate G-2

Above, the Department allowed the Company to rename current Rate T-2 as Rate G-2. Rate G-2 is available for all non-residential uses of electricity to all customers in the Boston Edison service area where the service voltage is less than 14,000 volts and the demand is equal to or greater than 100 kW for twelve consecutive months (Exhs. ES-RDC-1, at 20; ES-RDC-6, Sch. 1, at 146). Currently, Rate T-2 has a four-block customer charge ranging from $27.00 to $360.00 per month, a summer period demand charge of $22.21 per kW, and a winter period demand charge of $12.66 per kW (Exh. ES-RDC-2, Sch. 13, at 2 (Rev. 3)). The Company proposes no changes to the monthly customer charges for the first three blocks, and to increase the fourth block from $360.00 per month to $370.00 per month (for customers using more than 1,000 kW) (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). Further, the Company proposes a single demand charge of $17.31 per kW (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-2 is $66.07 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the current monthly customer charge structure, $27.00 for customers using up to 150 kW, $110.00 for customers using more than 150 kW but equal to or less than 300 kW, $160.00 for customers using more than 300 kW but less than or equal to 1,000 kW, and $370.00 for customers using more than 1,000 kW, for current Rate T-2 best meets our rate design goals and objectives and, therefore, we approve these customer charges for proposed Rate G-2. The Company shall set a single demand rate for all Rate G-2 customers to recover the remaining class revenue requirement approved in this Order.

c. Cambridge Electric Light Service Area

i. Company Proposal

(A) Rate G-2

Cambridge Electric Light Rate G-2 is available for all uses of electricity to customers in the Cambridge Electric Light service area where the service voltage is less than 13,800 volts and the demand exceeds or is estimated to exceed 100 kW for at least twelve consecutive billing months (Exh. ES-RDC-6, Sch. 1, at 155). The current monthly customer charge for Rate G-2 is $97.00, the demand charge for customers using less than or equal to 100 kVA is $4.63 per kVA, and $5.73 per kVA for customers using more than 100 kVA, and the energy charge is $0.01085 per kWh (Exh. ES-RDC-2, Sch. 13, at 3 (Rev. 3)). The Company proposes to increase the monthly customer charge to $110.00, to broaden the current demand charge of $4.63 per kVA to all customers taking service under this rate, and to increase the energy charge to $0.01479 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-2 is $89.69 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $110.00 best meets our rate design goals and objectives and, therefore, is approved. The Company shall set the demand charge to $4.63 per kW, as proposed, as it is equal to the current first block demand charge and therefore meets our goal of continuity. The Company shall further develop a single energy charge to recover the remaining class distribution revenue requirement approved in this Order.

d. Commonwealth Electric Service Area

i. Company Proposal

(A) Rate G-2

Commonwealth Electric Rate G-2 is a TOU rate, available for all uses of electricity to customers in the South Shore, Cape Cod, and Martha's Vineyard service area with demands in excess of 100 kW but not greater than 500 kW for at least twelve consecutive months (Exh. ES-RDC-6, Sch. 1, at 186). The current monthly customer charge for Rate G-2 is $370.00, the demand charge is $1.78 per kW, and the energy charges are $0.02076 per kWh for peak load period, $0.01747 per kWh for low load period A, and $0.01133 per kWh for low load period B[223] (Exh. ES-RDC-2, Sch. 13, at 5 (Rev. 3)). The Company proposes to maintain the current monthly customer charge, set the demand charge to $3.02 per kW, and set the energy charge for all hours to $0.01401 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-2 is $205.68 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $370.00 best meets our rate design goals and objectives and,

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223 The Company defines the load periods for this rate as follows:

> Peak Load Period: During that portion of the year when eastern daylight savings time is in effect, the period beginning at 9:00 a.m. and ending at 6:00 p.m. on all weekdays, Monday through Friday. During that portion of the year when eastern standard time is in effect, the period beginning at 4:00 p.m. and ending at 9:00 p.m. on all weekdays, Monday through Friday.
>
> Low Load Period: All hours not included in the Peak Load Period. The Low Load Period shall be further divided into 2 separate time periods as follows:
>
> Low Load Period A: All hours not included in the Peak Load Period or Low Load Period B.
>
> Low Load Period B: During both eastern daylight savings time and eastern standard time, the period beginning at 10:00 p.m. and ending at 7:00 a.m. on all weekdays, Monday through Friday, and all hours on Saturday and Sunday.

(Exh. ES-RDC-6, Sch. 2, at 140).

therefore, is approved. The Department also finds that the proposed demand charge of $3.02 per kW meets our rate design goals and objectives and, therefore, is approved. The Company shall develop a single volumetric rate for Rate G-2 to recover the remaining class revenue requirement approved in this Order.

e. WMA Service Area

i. Company Proposal

(A) Rate G-2

WMA Rate G-2 is available only to the entire use of electricity at a single location in the WMA service area with demand use greater than 100 kW, but not in excess of 349 kW (Exh. ES-RDC-6, Sch. 1, at 214). All electricity use is required to be measured through one meter, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of electricity use may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 214). All electricity supplied is required to be for the exclusive use of the customer and cannot be resold (Exh. ES-RDC-6, Sch. 1, at 214). With the approval of the Company, the customer may furnish electricity to persons or entities who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure or control the use of, any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 214). Rate 23 may be used in conjunction with this rate and is separately billed (Exh. ES-RDC-6, Sch. 1, at 214).

Rate G-2 is proposed to serve customers using more than 100 kW of demand from current Rate G-0 and Rate G-2 (Exh. ES-RDC-1, at 61, 63).

The current monthly customer charge for Rate G-0 is $30.00 for metered service and $15.00 for unmetered service, the demand charge is $10.83 per kW for customers with demand greater than 2 kW, and the energy charge is $0.00213 per kWh (Exh. ES-RDC-2, Sch. 13, at 5 (Rev. 3)). The current monthly customer charge for Rate G-2 is $353.00, the demand charge is $1.99 per kW for demand less than or equal to 50 kW, $9.37 per kW for demand over 50 kW, and the energy charge is $0.00210 per kWh (Exh. ES-RDC-2, Sch. 13, at 6 (Rev. 3)). For Rate G-2 the Company proposes a monthly customer charge of $110.00, a demand charge of $9.37 per kW, and an energy charge of $0.00417 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)).

(B) Rate T-4

WMA Rate T-4 is a TOU offering applicable only to the entire use of electricity at a single location in the WMA service area, for demand greater than 100 kW but not to exceed 349 kW (Exh. ES-RDC-6, Sch. 1, at 217). All electricity delivered is required to be measured through one meter (Exh. ES-RDC-6, Sch. 1, at 217). Also, all electricity supplied is required to be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 217). With the approval of the Company, the customer may furnish electricity to persons or concerns who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure, or control the use of, any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 217). Rate T-4 is proposed to serve customers using more than 100 kW of demand from current Rates T-0 and T-4 (Exh. ES-RDC-1, at 63).[224]

The current monthly customer charge for Rate T-0 is $30.00, the demand charge is $10.50 per kW for customers with demand greater than 2 kW, the peak energy charge is $0.00329 per kWh, and the off-peak energy charge is $0.00088 per kWh (Exh. ES-RDC-2, Sch. 13, at 6 (Rev. 3)). The current monthly customer charge for Rate T-4 is $353.00, the demand charge is $1.99 per kW for demand under or equal to 50 kW, and $9.37 per kW for demand over 50 kW, the peak energy charge is $0.00315 per kWh, and the off-peak energy charge is $0.00089 per kWh (Exh. ES-RDC-2, Sch. 13, at 7 (Rev. 3)). For Rate T-4 the Company proposes a monthly customer charge of $110.00, a demand charge of $9.37 per kW, a peak energy charge of $0.00891 per kWh, and an off-peak energy charge of $0.00252 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for proposed Rate G-2 and Rate T-4 is $122.79 per month (Exh. ES-ACOS-2, at 12 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $110.00 best meets our rate design goals and

[224] As noted above, the Department approved the cancellation of Rate T-0.

objectives and, therefore, is approved for each rate. The Company shall set the demand charge, as proposed, to $9.37 per kW as this is less than or equal to all current demand charges for most of the relevant customers, and therefore meets our goal of continuity. For Rate G-2 the Company shall set the energy charge to recover the remaining class distribution revenue requirement approved in this Order. For Rate T-4 to recover the remaining class distribution revenue requirement approved in this Order, the Company shall set the peak and off-peak energy charges such that they maintain the same ratio to the current energy charges.

6. Large General Service Rates

a. Introduction

Similar to the medium C&I rate grouping, in Section XVII.B.3.b above, the Department allowed the Company's proposal to eliminate seasonal pricing and eliminate the demand block design where used (Exh. ES-RDC-1, at 53). The rate structure for Boston Edison and Cambridge Electric Light will not change (Exh. ES-RDC-1, at 18).

b. Boston Edison Service Area

i. Company Proposal

(A) Rate G-3

Boston Edison Rate G-3 is available for all use at a single location in the Boston Edison service area on contiguous private property if service is supplied to the customer and metered at 14,000 volts nominal or greater and if the customer furnishes, installs, owns, and maintains at its expense all protective devices, transformers, and other equipment required by the Company (Exh. ES-RDC-6, Sch. 1, at 140). The current monthly customer charge for Rate G-3 is $250.00, the summer period demand charge is $16.60 per kW, and the winter period demand charge is $9.78 per kW (Exh. ES-RDC-2, Sch. 14, at 1 (Rev. 3)). The Company proposes to increase the monthly customer charge to $370.00 and to implement a single demand charge of $15.34 per kW (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)).

(B) Rate WR

Rate WR is available for electricity supplied and delivered in bulk for the purpose of construction and operation of the Deer Island Wastewater Treatment Facility from NSTAR Electric's K Street Transmission Station (Exh. ES-RDC-6, Sch. 1, at 149). The customer charge is currently $150.48 per month and there are no volumetric charges (Exh. ES-RDC-2, Sch. 14, at 1 (Rev. 3)). The Company proposes to increase the customer charge to $157.16 per month (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 is $129.72 per month (Exh. ES-ACOS-2, at 9 (Rev. 3)). The existing embedded monthly customer charge for proposed Rate WR is $127.32 (Exh. ES-ACOS-2, at 9 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of $370.00 for Rate G-3 best meets our rate design goals and objectives and, therefore, is approved. The Company shall set a single demand rate for Rate G-3 to recover the remaining class distribution revenue requirement for Rate G-3 approved in this Order. Further, the Company shall set a single customer charge for Rate WR to recover the class revenue requirement as approved in this

Order. Such rate design satisfies our simplicity goal, as well as our continuity goal because it produces bill impacts that are moderate and reasonable, considering the size of the increase.

c. Cambridge Electric Light Service Area

i. Company Proposal

(A) Rate G-3

Cambridge Electric Light Rate G-3 is available for all uses of electricity to customers in the Cambridge Electric Light service area whose metered load exceeds or is estimated to exceed 100 kW for at least twelve consecutive billing months and the service voltage is 13,800 volts or higher (Exh. ES-RDC-6, Sch. 1, at 159). The current monthly customer charge for Rate G-3 is $97.00, the demand charge is $4.74 per kVA for customers with load greater than 100 kVA of demand, and the energy charge at $0.00381 per kWh (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The Company proposes to increase the monthly customer charge to $370.00, set the demand charge for all levels of use at $5.92 per kW, and to maintain the energy charge at $0.00381 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3); Sch. 14, at 2 (Rev. 3)).

(B) Rate SB-1/MS-1/SS-1 (Closed)

Rate SB-1 is a closed rate for customers with a written application and execution of an electric service agreement, for those in the Cambridge Electric Light service area with an alternative source of power who requests firm delivery of standby service and for whom the Company has an obligation to serve (Exh. ES-RDC-6, Sch. 1, at 168). The Company must have the ability to meter the alternative source of power (Exh. ES-RDC-6, Sch. 1, at 168). Standby service is intended to deliver to the customer a replacement supply of power when the customer's alternative source of power is either partially or totally unavailable (Exh. ES-RDC-6, Sch. 1, at 168). A customer requesting standby service is required to take service under this rate schedule if the customer's alternative source of power (1) exceeds 100 kW, and (2) supplies at least 20 percent of the customer's total integrated electrical load (Exh. ES-RDC-6, Sch. 1, at 168).

Rate MS-1 is a closed rate for customers with a written application and execution of an electric service agreement, for those in the Cambridge Electric Light service area with an alternative source of power who requests delivery of maintenance service, and for whom the Company has an obligation to serve (Exh. ES-RDC-6, Sch. 1, at 173). The Company must have the ability to meter the alternative source of power. Maintenance service is intended to deliver to the customer electric energy and capacity to replace energy and capacity ordinarily generated by the facilities that make up the customer's alternative source of power when such facilities are withdrawn from service for maintenance scheduled in accordance with defined provisions (Exh. ES-RDC-6, Sch. 1, at 173). A customer requesting maintenance service is required to take service under this rate schedule if the customer's alternative source of power (1) exceeds 100 kW, and (2) supplies at least 20 percent of the customer's total integrated electrical load (Exh. ES-RDC-6, Sch. 1, at 173).

Rate SS-1 is a closed rate for customers with a written application and execution of an electric service agreement, for those in the Cambridge Electric Light service area with an alternative source of power in operation prior to October 31, 2003, and for whom the Company has an obligation to serve (Exh. ES-RDC-6, Sch. 1, at 178). The Company must have the ability to meter the alternative source of power (Exh. ES-RDC-6, Sch. 1, at 178). Supplemental service is intended to deliver power to supplement the output of the customer's alternative source of power where the alternative source of power is less than the customer's maximum electrical load (Exh. ES-RDC-6, Sch. 1, at 178). A customer requesting supplemental service is required to take service under this rate schedule if the customer's alternative source of power (1) exceeds 100 kW, and (2) supplies at least 20 percent of the customer's total integrated electrical load (Exh. ES-RDC-6, Sch. 1, at 173).

Proposed rates Rate SB-1 and Rate MS-1 have a current monthly customer charge of $781.00 (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The standby demand charge for these rate classes is $6.48 per kW (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The supplemental demand charge for Rate SS-1, for customers with demand greater than 100 kVA, is $4.74 per kVA (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The supplemental energy charge for Rate SS-1 is equal to the energy charge for the otherwise applicable rate schedule, or Rate G-3, which is currently $0.00381 per kWh (Exh. ES-RDC-2, Sch. 14, at 2 (Rev. 3)). The Company proposes to increase the standby demand charge for Rates SB-1 and MS-1 to $7.59 per kW and the supplemental demand charge for Rate SS-1 to $5.92 per kVA, assuming the otherwise applicable rate class for the supplemental service customer is Rate G-3, for all demand levels (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). The Company proposes to maintain the current customer charge and supplemental distribution energy charge (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 is \$97.10 per month (Exh. ES-ACOS-2, at 10 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charge of \$370.00 best meets our rate design goals and objectives and, therefore, is approved. The Company shall set the demand charge as proposed to \$5.92 per kW, as this also best meets our rate design goals and objectives at this time. The Company shall develop a single energy rate for Rate G-3 to recover the remaining class revenue requirement for Rate G-3 approved in this Order. The Department further approves the Company's current and proposed monthly customer charge of \$781.00 for Rate SB-1 and Rate MS-1. The Company shall set a single demand charge to recover the remaining class revenue requirement approved in this Order for Rate SB-1 and a single demand charge to recover the remaining class revenue requirement approved in this Order for Rate MS-1. Rate SS-1 shall be charged using the rates approved for the otherwise applicable rate, usually Rate G-3.[225]

225 The Department notes that the Company's proposed Rate SS-1 tariff appears to incorrectly refer to "Standby Service" in the last sentence of the Availability clause (Exh. ES-RDC-6, Sch. 1, at 178). The Company is directed to make any necessary corrections to this sentence in its compliance filing.

d. Commonwealth Electric Service Area

i. Company Proposal

(A) Rate G-3

Commonwealth Electric Rate G-3 is available for all uses of electricity to customers in the South Shore, Cape Cod, and Martha's Vineyard service area who establish demands in excess of 500 kW for at least twelve consecutive months (Exh. ES-RDC-6, Sch. 1, at 190). The current monthly customer charge for Rate G-3 is $930.00, the demand charge is $1.01 per kVA, the peak load energy charge is $0.01443 per kWh, the low load A period energy charge is $0.01328 per kWh, and the low load B period energy charge is $0.00919 per kWh (Exh. ES-RDC-2, Sch. 12, at 3 (Rev. 3)). The Company proposes to maintain the monthly customer charge at $930.00, increase the demand charge to $3.33 per kW, and implement a single energy charge for all hours of $0.01156 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed this issue on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 is $494.05 per month (Exh. ES-ACOS-2, at 11 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that maintaining the monthly customer charge of $930.00, as proposed, and a demand charge of $3.33 per kW best meet our rate design goals and objectives and, therefore, are approved. Finally, the Company shall develop a single energy rate to recover the remaining class distribution revenue requirement for Rate G-3 approved in this Order.

e. WMA Service Area

i. Company Proposal

(A) Rate G-3

Proposed WMA Rate G-3 is applicable to current customers taking service under Rate T-2 (Exh. ES-RDC-1, at 65). This proposed rate class is only for use of electricity at a single location in the WMA service area. All electricity is required to be measured through a single TOU meter installed by the Company, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of electricity may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 220). All electricity supplied shall be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 220). With the approval of the Company, the customer may furnish electricity to persons or concerns who occupy space in the building to which service is supplied, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure, or control the use of, any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 220).

The current monthly customer charge for Rate T-2 is a three-block rate, ranging from $760.00 to $2,700.00 (Exh. ES-RDC-2, Sch. 14, at 3 (Rev. 3)). The current demand charge is $7.29 per kW, the current peak energy charge is $0.00297 per kWh, and the current off-peak energy charge is $0.00087 per kWh (Exh. ES-RDC-2, Sch. 14, at 3 (Rev. 3)). For Rate G-3, the Company proposes to maintain the existing customer charges and energy charges for current Rate T-2, as well as proposes to increase the distribution demand charge to $10.28 per kW (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)).

(B) Rate T-5

Rate T-5 is only available where the entire use of electricity is at a single location in the WMA service area (Exh. ES-RDC-6, Sch. 1, at 223). All electricity is measured through a single TOU meter installed by the Company, except that, where the Company deems it impractical to deliver electricity through one service, or where more than one meter has been installed, then the measurement of electricity may be by two or more meters (Exh. ES-RDC-6, Sch. 1, at 223). Also, all electricity supplied is required to be for the exclusive use of the customer and shall not be resold (Exh. ES-RDC-6, Sch. 1, at 223). With the approval of the Company, the customer may furnish electricity to persons or concerns who occupy space in the building to which service is supplied hereunder, but on the express condition that the customer shall not resell, make a specific charge for, or re-meter (or sub-meter) or measure or control the use of any of the electricity so furnished (Exh. ES-RDC-6, Sch. 1, at 223).

The current customer charge for Rate T-5 is $3,800.00 per month and the current demand charge is $5.18 per kW (Exh. ES-RDC-2, Sch. 14, at 4 (Rev. 3)). The Company also has a peak energy charge of $0.00296 per kWh and an off-peak energy charge of $0.00087 per kWh (Exh. ES-RDC-2, Sch. 14, at 4 (Rev. 3)). The Company proposes to maintain the current customer charge and off-peak energy charge but increase the demand charge to \$8.08 per kW and to increase the peak energy charge to \$0.00297 per kWh (Exh. ES-RDC-2, Sch. 1, at 2 (Rev. 3)). No party addressed these issues on brief.

ii. Analysis and Findings

According to the Company's ACOSS, the existing embedded customer charge for proposed Rate G-3 (i.e., current Rate T-2) is \$432.36 per month and for proposed Rate T-5 is \$1,910.10 per month (Exh. ES-ACOS-2, at 12 (Rev. 3)). Based on a review of embedded costs and the bill impacts on customers, the Department finds that the proposed monthly customer charges of \$760.00 for use between 350 kW and 1,000 kW, \$1,625.00 for customers using equal to or greater than 1,000 kW but less than 1,500 kW, and \$2,700.00 for customers using equal to or greater than 1,500 kW but less than 2,500 kW for proposed Rate G-3 and \$3,800.00 for Rate T-5 best meet our rate design goals and objectives. Therefore, the Department approves each of these monthly customer charges. The Company shall develop separate demand charges for Rate G-3 and Rate T-5, as well as peak and off-peak energy rates for both Rate G-3 and Rate T-5 together, to recover the remaining class distribution revenue requirements approved in this Order in proportion with the current energy rates.

7. Streetlighting and LED Streetlight Rates

a. Introduction

The Company proposes new rate design for Rates S-1 and S-2; Company and customer-owned streetlights, respectively (Exh. ES-RDC-1, at 65). The Company states that currently, similar to distribution rates for other customers, streetlight rates contain customer and demand components that represent the cost of service to provide them (Exh. ES-RDC-1, at 65-66). In addition, streetlight rates have direct assigned costs that constitute a facilities charge, which differentiates the rates for Company-owned streetlights from customer-owned streetlights (Exh. ES-RDC-1, at 66). The Company proposes to use the total costs for customer, demand, O&M, and facility components for Rate S-1, and the total costs for customer and demand for Rate S-2 (Exh. ES-RDC-1, at 66).

For Rate S-1, the Company proposes to adjust all rates by the percentage needed to reach the target revenue requirement (Exh. ES-RDC-1, at 66). Specifically, for Rate S-1, the Company proposes to increase the rates for each luminaire, pole, and accessory by 19.9 percent to meet the adjusted class target revenue for Rate S-1 (Exhs. ES-RDC-1, at 66; ES-RDC-5, Sch. 1 (Rev. 3)). The class target revenue requirement was adjusted to exclude the proposed revenues from LED lights (Exh. ES-RDC-5, Sch. 2, at 2-4 (Rev. 3)).

As LED light pricing has decreased in recent years, the Company proposes to revise LED streetlight pricing to reflect the total installed cost for each offering (Exhs. ES-RDC-1, at 67; ES-RDC-5, Sch. 3, at 1 (Rev. 3). The Company proposes to then apply a carrying charge to the LED installed cost, to derive the total revenue requirement, which is then divided by twelve to derive a monthly fixed charge (Exh. ES-RDC-1, at 67).

For Rate S-2, the Company proposes to develop a per-kWh charge to meet the target revenue requirement (Exhs. ES-RDC-1, at 66, ES-RDC-5, Sch. 2, at 6 (Rev. 3). Rate S-2 customers in the EMA service area have a customer charge and an energy charge; Rate S-2 customers in the WMA service area are billed based on lamp wattage (Exh. ES-RDC-1, at 68). For both the EMA and WMA service areas the Company proposes to implement a per-kWh energy rate calculated by dividing the class target revenue by the annual kWh sales for the rate class (Exh. ES-RDC-1, at 67-68). No party addressed these issues on brief.

b. Analysis and Findings

The Department has reviewed the Company's proposed changes for calculating streetlighting rates (Exhs. ES-RDC-1, at 65-68; ES-RDC-5 (Rev. 3)). 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, are approved. In addition, the Department approves the revised LED streetlight pricing as proposed. Accordingly, the Department approves the rate design for streetlighting using the method proposed by the Company.

XVIII. TARIFF CHANGES

A. Terms and Conditions – Distribution Service

1. Introduction

The Company proposes four categories of changes to the appendices within its Terms and Conditions – Distribution Service tariff: (1) updates to the Schedule of Fees and Charges in Appendix A; (2) updates to the revenue multiplier in Appendix B used to credit customers for any contribution in aid of construction ("CIAC"); (3) the addition of "clarifying language" to the Appendix B sections that address line extension responsibilities; and (4) updates to the list of cities and towns in Appendix C (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 20, 25, 26, 34, 35, 39, 44, 46, 48, 50-52). No party addressed these proposed changes on brief.

2. Analysis and Findings

With respect to the Schedule of Fees and Charges in Appendix A, the Company proposes to maintain the Returned Check Fee of $11.00; increase its Account Restoration Charge for meters from $30.00 to $103.00; increase its Account Restoration Charge for poles from $101.00 to $123.00; increase its Account Restoration Charge for manholes from $161.00 to $181.00; increase its Warrant Fee from $98.00 to $240.00; and decrease its Sales Tax Abatement Fee from $52.00 to $32.00 (Exhs. ES-RDC-6, Sch. 2, at 20; ES-RDC-7, WPs 3 through 5 (Rev. 2)).

Fees for ancillary services such as processing returned checks are intended to reimburse a company for actual costs incurred in providing these services. See, e.g., D.P.U. 17-05, at 735; D.P.U. 95-118, at 84; Whitinsville Water Company, D.P.U. 89-67, at 4-5 (1989); D.P.U. 956, at 62. The Department has found that fees for these various services must be based on the costs associated with these functions that the company actually incurred. DPU 17-05, at 735; D.P.U. 08-35, at 58; D.P.U. 89-67, at 4; D.P.U. 956, at 62. While the Department has accepted gradual adjustments to fees, excessive increases in a single step may violate the Department's continuity goal. D.P.U. 17-05, at 735; D.T.E. 05-27, at 354-355.

The Department has reviewed NSTAR Electric's proposed changes to its Schedule of Fees and Charges and the supporting calculations and assumptions, and we find that the changes are reasonable and based on the costs associated with these functions that the Company incurs (Exhs. ES-RDC-6, Sch. 2, at 20; ES-RDC-7, WPs 3 through 5 (Rev. 2); DPU 11-21; DPU 31-12; Tr. 8, at 868-879). Further, the Department finds that the Company has correctly incorporated the additional revenues associated with the fee increases as a revenue credit in its proposed costs of service (Exhs. ES-REVREQ-1, at 50-51; ES-REVREQ-2, Schs. 1, 6 (Rev. 4); ES-REVREQ-3, WP 6 (Rev. 4)). We note, however, that the Company rounded, rather than truncated, the proposed fees and charges identified in Appendix A. To ensure that the proposed fees and charges do not collect more than the costs for providing the particular service, the Department directs the Company to truncate the amounts at whole dollars (Exh. DPU 31-12). Accordingly, the Company's approved Schedule of Fees and Charges are: Returned Check Fee of $10.00;[226] Account Restoration Charge for meters of $102.00; Account Restoration Charge for poles of $123.00; Account Restoration Charge for manholes of $180.00; Warrant Fee of $240.00; and Sales Tax Abatement Fee of $31.00 (Exhs. DPU 31-4 & Att.; ES-RDC-7, WPs 3 through 5 (Rev. 2)). The effect of the approved fees and charges on the Company's revenues are reflected in the Department's Schedule 9 below.

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[226] NSTAR Electric proposed to maintain the current Returned Check Fee of $11.00 based on the Company's proposed ten-year PBR term (Exh. DPU 31-4). The Company concedes, however, that the cost for this service is $10.00 (Exh. DPU 31-4). Moreover, the Department has rejected the Company's proposed ten-year PBR term (see Section IV.D.5.a above).

Next, the Company proposes to update the revenue multiplier in Appendix B used to credit customers for any CIAC (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 39, 48). NSTAR Electric's current line extension policy provides that if a developer makes a CIAC for a line extension located within a way that is accepted by the municipality as a public way, that developer shall be refunded an amount equal to 3.6 times the annual revenues estimated to be received by the Company associated with the line extension for the development, subject to a maximum refund that is no greater than the contribution itself (Exh. ES-RDC-6, Sch. 2 at 39, 48). The Company proposes to increase this revenue multiplier to 4.1 times the annual revenues that the Company estimates will be received from the line extension (Exhs. ES-RDC-6, Sch. 2 at 39, 48; ES-RDC-7, WP 6, (Rev. 2)). The Department has reviewed the Company's supporting calculations (Exhs. ES-RDC-6, Sch. 2, at 39, 48; ES-RDC-7, WP 6 (Rev. 2); DPU 11-21; Tr. 8, at 880). The Department directs the Company to recalculate the CIAC revenue multiplier using the revenue requirement components as determined in this Order and submit the calculations as part of its compliance filing.

NSTAR Electric also proposes to include in Appendix B language regarding certain responsibilities for costs that arise during maintenance, repair, or restoration work by the Company on customer property (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 25, 26, 34, 35, 44, 46). The Department has reviewed the proposed language and the supporting record, and we find the proposed language acceptable (Exhs. DPU 29-1; Tr. 8, at 885-894;

RR-AG-21 through RR-AG-24). As such, the Company may include this language in its Terms and Conditions – Distribution Service tariff.

Finally, NSTAR Electric proposes to update the list of cities and towns that the Company serves in its EMA and WMA service areas (Exhs. ES-RDC-1, at 70; ES-RDC-6, Sch. 2, at 50-52). The Department finds this proposal to be reasonable and appropriate and, therefore, we approve the proposed changes to Appendix C.

Based the considerations above, NSTAR Electric is directed to file a revised Terms and Conditions – Distribution Service tariff with its compliance filing, consistent with the findings above.

B. Other Tariff Provisions

The Company proposes changes to its other tariffs to reflect the proposals submitted in this case or to update current tariff language (see generally Exh. ES-RDC-6, Sch. 2). In the various sections of this Order, the Department has addressed Company proposals that implicate a number of the proposed tariff changes (e.g., PBR mechanism proposals, vegetation management proposals, storm fund proposals). The Department directs the Company to make all appropriate tariff changes consistent with the Department's findings in those sections. The Department has reviewed all remaining proposed tariff changes not specifically addressed elsewhere in this Order or not associated with an issue that is specifically addressed in this Order. We find these proposed changes to be reasonable, and, therefore, we approve the changes. The Company shall file revised tariffs, as appropriate, with its compliance filing.

XIX. SCHEDULES

A. Schedule 1 – Revenue Requirements and Calculation of Revenue Increase

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER	
COST OF SERVICE					
Total O&M Expense	461,098,686	1,264,605	(34,145,265)	428,218,026	
Uncollectible O&M due to increase	619,920	27,280	(202,161)	445,039	
Depreciation & Amortization	252,847,877	(7,740,625)	(27,087,735)	218,019,517	
Taxes Other Than Income Taxes	147,739,020	12,868,998	(5,919,880)	154,688,138	
Income Taxes	92,636,063	(4,567,460)	(8,987,989)	79,080,614	
Return on Rate Base	311,997,775	(7,753,952)	(26,938,141)	277,305,682	
Total Cost of Service	1,266,939,341	(5,901,154)	(103,281,171)	1,157,757,016	
OPERATING REVENUES					
Total Distribution Revenues	1,146,568,761	(11,390,573)	(74,004,799)	1,061,173,390	
Other Revenues	30,892,717	1,523,794	(88,188)	32,328,323	
Total Operating Revenues	1,177,461,478	(9,866,779)	(74,092,987)	1,093,501,713	
Total Revenue Deficiency	**89,477,863**	**3,965,625**	**(29,188,185)**	**64,255,303**	*

* The Total Revenue Deficiency is adjusted for AMR/legacy CIS & MDMS, Vegetation Management, and SMART Program that are currently recovered or were proposed to be recovered in base rates and will be transferred or remain for recovery through reconciling mechanisms pursuant to the directives in this proceeding.

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

B. Schedule 2 – Operations and Maintenance Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Test Year O&M Expense	410,768,033	(2,150,638)	0	408,617,395
ADJUSTMENTS TO O&M EXPENSE:				
Compensation: Payroll Expense	13,138,206	105	0	13,138,311
Compensation: Variable Compensation	(6,821,176)	0	(3,232,371)	(10,053,547)
Dues and Memberships	0	0	(363,166)	(363,166)
Employee Benefits Costs	7,164,314	955,023	0	8,119,337
Enterprise IT Projects Expense (includes AMI and SMART)	10,869,443	(2,963,414)	(3,657,238)	4,248,791
Insurance Expense And Injuries & Damages	1,462,386	709,186	(500,410)	1,671,162
Work Asset Management Training	0	0	(2,777,920)	(2,777,920)
Postage Expense	100,368	0	0	100,368
Lease Expense	942,762	(303,318)	0	639,444
Regulatory Assessments	0	(1,182,653)	0	(1,182,653)
Rate Case Expense	763,234	(141,596)	0	621,638
Uncollectible Expense	(1,166,264)	(4,238)	0	(1,170,502)
Resiliency Tree Work Program	0	0	(23,200,000)	(23,200,000)
Storm Fund Adjustment	21,000,000	0	0	21,000,000
Storm Cost Adjustment	(4,200,000)	0	0	(4,200,000)
Residual O&M Inflation Adjustment	7,077,380	6,346,148	(414,160)	13,009,368
Total Adjustment to O&M Expense	50,330,653	3,415,243	(34,145,265)	19,600,631
Total O&M Expense	**461,098,686**	**1,264,605**	**(34,145,265)**	**428,218,026**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

C. Schedule 2A – Inflation Table

Test Year O&M Expense	$ 408,617,395
	$ 408,617,395
Less: Company Adjustments	
Compensation: Payroll Expense	$ 144,958,863
Compensation: Variable Compensation	$ 16,503,810
Dues and Memberships	$ 802,347
Employee Benefits Costs	$ 15,617,670
Enterprise IT Projects Expense	$ 33,020,432
Insurance Expense and Injuries & Damages	$ 4,035,454
Postage Expense	$ 4,338,141
Lease Expense	$ 7,010,708
Regulatory Assessments	$ 11,804,920
Uncollectibles Expense	$ 15,281,020
Vegetation Management Expense[227]	$ 43,207,619
Storm Fund Adjustment	$ 10,000,000
Storm Cost Adjustment	$ 12,000,000
Total Company O&M Adjustments	$ 318,580,984
Residual O&M Expense Subject to Inflation per Company	$ 90,036,411
Inflation Factor	14.909%
Inflation Allowance per Company	$ 13,423,528
Less: Department Adjustments	
Work Asset Management Training	$ 2,777,920
Department Sub-total	$ 2,777,920
Residual O&M Expense Subject to Inflation per DPU	$ 87,258,491
Inflation Factor	14.909%
Inflation Allowance per DPU	$ 13,009,368

[227] The Department transferred $23,200,000 from the Company's test year Vegetation Management expense to a reconciling mechanism in Section XI.C.4.b above. That transfer, however, is not reflected here because it would necessitate a corresponding adjustment to the test year O&M expense of $408,617,395, and thus, would result in no change to the approved inflation allowance.

D. Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation and Amortization Expense	231,820,683	(7,126,708)	(27,087,735)	197,606,240
Amortization of Deferred Assets	21,027,194	(613,917)	0	20,413,277
Total Depreciation and Amortization Expense	**252,847,877**	**(7,740,625)**	**(27,087,735)**	**218,019,517**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

E. Schedule 4 – Rate Base and Return on Rate Base

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Utility Plant in Service	8,158,167,577	(257,233,638)	(328,863,241)	7,572,070,698
LESS:				
Reserve for Depreciation	2,611,720,164	(62,449,509)	(120,017,193)	2,429,253,462
Reserve for Amortization	49,613,183	(2,196,844)	0	47,416,339
Net Utility Plant in Service	5,496,834,230	(192,587,285)	(208,846,048)	5,095,400,897
ADDITIONS TO PLANT:				
Cash Working Capital	53,688,003	1,276,279	(3,616,840)	51,347,443
Materials and Supplies	52,956,389	4,165,283	0	57,121,672
Total Additions to Plant	106,644,392	5,441,562	(3,616,840)	108,469,115
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	733,301,500	11,030,397	(47,343,789)	696,988,108
FAS 109 Regulatory Liability (net)	560,994,216	(28,674,651)	0	532,319,565
Customer Deposits	5,032,962	(789,353)	0	4,243,609
Customer Advances	40,487,331	(237,788)	0	40,249,543
Total Deductions from Plant	1,339,816,009	(18,671,395)	(47,343,789)	1,273,800,825
RATE BASE	4,263,662,613	(168,474,328)	(165,119,099)	3,930,069,187
COST OF CAPITAL	7.32%	0.11%	-0.37%	7.06%
RETURN ON RATE BASE	**311,997,775**	**(7,753,952)**	**(26,938,141)**	**277,305,682**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

F. Schedule 5 – Cost of Capital

PER COMPANY

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$4,020,000,000	45.71%	3.60%	1.65%
Preferred Stock	$43,000,000	0.49%	4.56%	0.02%
Common Equity	$4,731,109,220	53.80%	10.50%	5.65%
Total Capital	$8,794,109,220	100.00%		7.32%
Weighted Cost of				
Debt				1.65%
Preferred				0.02%
Equity				5.65%
Cost of Capital				7.32%

ADJUSTED PER COMPANY

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$4,470,000,000	46.34%	3.93%	1.82%
Preferred Stock	$43,000,000	0.45%	4.56%	0.02%
Common Equity	$5,133,109,220	53.21%	10.50%	5.59%
Total Capital	$9,646,109,220	100.00%		7.43%
Weighted Cost of				
Debt				1.82%
Preferred				0.02%
Equity				5.59%
Cost of Capital				7.43%

PER ORDER

	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$4,470,000,000	46.34%	3.93%	1.82%
Preferred Stock	$43,000,000	0.45%	4.56%	0.02%
Common Equity	$5,133,109,220	53.21%	9.80%	5.22%
Total Capital	$9,646,109,220	100.00%		7.06%
Weighted Cost of				
Debt				1.82%
Preferred				0.02%
Equity				5.22%
Cost of Capital				**7.06%**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

G. Schedule 6 – Cash Working Capital

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Electric O&M Expenses	461,098,686	1,264,605	(34,145,265)	428,218,026
Less Uncollectible Accounts	14,114,756	(4,238)	0	14,110,518
Taxes Other Than Income	147,739,020	12,868,998	(5,919,880)	154,688,138
Total Costs Applicable to Cash Working Capital	**594,722,950**	**14,137,841**	**(40,065,145)**	**568,795,646**
Cash Working Capital Factor (32.95 Days/365)	9.03%	9.03%	9.03%	9.03%
Cash Working Capital Adjustment	**53,688,003**	**1,276,279**	**(3,616,840)**	**51,347,443**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

H. Schedule 7 – Taxes Other Than Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Property Taxes	134,635,202	12,868,998	(5,919,880)	141,584,320
FICA	9,519,756	0	0	9,519,756
Medicare	2,893,609	0	0	2,893,609
Federal Unemployment	33,112	0	0	33,112
State Unemployment	281,813	0	0	281,813
State Insurance Premium Excise Tax	86,154	0	0	86,154
Universal Health (MA)	34,708	0	0	34,708
State Sales and Use Tax	253,980	0	0	253,980
Paid Family Medical Leave	686	0	0	686
Total Taxes Other Than Income Taxes	**147,739,020**	**12,868,998**	**(5,919,880)**	**154,688,138**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

I. Schedule 8 – Income Taxes

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Rate Base	4,263,662,613	(168,474,328)	(165,119,099)	3,930,069,187
Return on Rate Base	311,997,775	(7,753,952)	(26,938,141)	277,305,682
ADJUSTMENTS				
Flow Through and Permanent Items	4,100,992	0	0	4,100,992
FAS 109 Income Taxes and ITC	147,235	0	0	147,235
Interest Expense	(70,196,941)	(4,396,914)	3,027,295	(71,566,560)
Excess ADIT Amortization	0	0	0	0
Total Deductions	(65,948,714)	(4,396,914)	3,027,295	(67,318,333)
Taxable Income Base	246,049,061	(12,150,866)	(23,910,847)	209,987,349
Gross Up Factor	1.3759	1.3759	1.3759	1.3759
Taxable Income	338,538,904	(16,718,376)	(32,898,934)	288,921,593
Mass Income Tax (8%)	27,083,112	(1,337,470)	(2,631,915)	23,113,727
Federal Taxable Income	311,455,792	(15,380,906)	(30,267,019)	265,807,866
Federal Income Tax (21%)	65,405,716	(3,229,990)	(6,356,074)	55,819,652
Total Income Taxes Calculated	92,488,828	(4,567,460)	(8,987,989)	78,933,379
FAS 109 Income Taxes and ITC	147,235	0	0	147,235
Less: Excess ADIT Amortization	0	0	0	0
Total Income Taxes	**92,636,063**	**(4,567,460)**	**(8,987,989)**	**79,080,614**

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

J. Schedule 9 – Revenues

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Distribution Revenue *	973,557,967	0	(48,911,081)	924,646,886
Revenue Decoupling - (Prior Year Billed)	13,545,230	0	0	13,545,230
Revenue Decoupling - Accrual	34,496,381	0	0	34,496,381
Resiliency Tree Work Pilot- RTW	23,200,000	0	(23,200,000)	0
Solar Expansion Revenue	21,700,536	0	0	21,700,536
Solar Program WMA Revenue	33,394	(33,394)	0	(0)
MA Smart Solar Revenue	1,893,718	0	(1,893,718)	0
Grid Mod Tracked Revenue	11,357,179	(11,357,179)	0	0
Additional PBR Revenue	66,784,356	0	0	66,784,356
Total Distribution Revenue	1,146,568,761	(11,390,573)	(74,004,799)	1,061,173,390
Other Revenues				
Sales for Resale	43,330	0	0	43,330
Provision for Rate Refunds	0	0	0	0
Forfeited Accounts	704,134			704,134
Misc. Service Revenues	5,046,344	43,916	(88,188)	5,002,072
Rent from Electric Property	15,197,523	1,479,878	0	16,677,401
Other Electric Revenue	9,901,386	0	0	9,901,386
Revenues from Transmission of Electricity of Others	0	0	0	0
Total Other Revenues	30,892,717	1,523,794	(88,188)	32,328,323
Adjusted Total Operating Revenues	**1,177,461,478**	**(9,866,779)**	**(74,092,987)**	**1,093,501,713**

* The DPU Adjustment is to remove revenue to be collected through the new AMI factor.

Numbers may not add due to rounding. Minor discrepancies between these numbers and those in the text are due to rounding.

K. Schedule 10 – Allocation to Rate Groups and Rate Classes

Schedule 10 – Group – For illustrative purposes only

Rate Group	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates*	Base Rate Transfers	Base Distribution Revenue at EROR	Change in Reconciling Revenue	Base Distribution Revenue Increase at EROR
	(a)	(b)	(c)	(d)	(e)	(f)
Residential	$2,082,953,605	$519,018,176	-$13,403,878	$574,063,620	$35,189,655	$55,045,444
Small General Service	$965,130,376	$223,538,825	-$5,772,991	$217,025,171	$9,717,048	-$6,513,655
Medium General Service	$1,007,330,174	$194,675,611	-$5,027,585	$193,655,596	-$2,844,217	-$1,020,015
Large General Service	$823,018,000	$105,805,745	-$2,732,481	$125,912,174	$3,654,648	$20,106,429
Lighting - Company	$15,029,424	$8,115,357	-$209,583	$10,393,544	$28,617	$2,278,187
Lighting - Customer	$11,316,117	$2,143,829	-$55,365	$2,701,846	-$42,848	$558,017
Total Company	$4,904,777,696	$1,053,297,543	-$27,201,883	$1,123,751,951	$45,702,903	$70,454,408

* The Total Company Base Distribution Revenue at Current Rates shown in column (b) differs from the Total Distribution Revenues shown on Schedule 1 because the total shown above in column (b) was calculated using rates in effect January 1, 2022 and 2021 calendar year billing quantities, while the total distribution revenues shown on Schedule 1 was determined by taking normalized test year distribution revenues and adjusting them for the additional PBR revenues, transfers from reconciling items, and revenue decoupling. The difference in the distribution revenues between the two schedules also results in a difference in the revenue deficiency between these two schedules.

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Group	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
	(g)	(h)	(i)	(j)	(k)	(l)
Residential	$208,295,360	$0	$574,063,620	$414,483	$90,649,582	$0
Small General Service	$96,513,038	$0	$217,025,171	$156,695	$3,360,089	$0
Medium General Service	$100,733,017	$0	$193,655,596	$139,822	-$3,724,409	$0
Large General Service	$82,301,800	$0	$125,912,174	$90,910	$23,851,988	$0
Lighting - Company	$1,502,942	$803,861	$0	$0	$1,502,942	$0
Lighting - Customer	$1,131,612	$0	$2,701,846	$1,951	$517,120	$0
Total Company	$490,477,770	$803,861	$1,113,358,407	$803,861	$116,157,311	$0

Schedule 10 – Group continued – For illustrative purposes only

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Group	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
	(m)	(n)	(o)	(p)	(q)	(r)
Residential	$69,433,597	$0	$574,063,620	$3,908,501	$59,368,428	$0
Small General Service	$29,904,742	$0	$217,025,171	$1,477,612	-$4,879,347	$0
Medium General Service	$26,043,458	$0	$193,655,596	$1,318,500	$438,308	$0
Large General Service	$14,154,559	$6,042,780	$0	$0	$14,154,559	$0
Lighting - Company	$1,085,662	$388,664	$0	$0	$1,085,662	$0
Lighting - Customer	$286,799	$273,169	$0	$0	$286,799	$0
Total Company	$140,908,816	$6,704,613	$984,744,387	$6,704,613	$70,454,408	$0

BASE DISTRIBUTION REVENUE FLOOR					
	ITERATION 1				
Rate Group	**Base Distribution Revenue Decrease**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenue Decrease**	**Base Distribution Revenue After Reallocation**	**Base Distribution Revenue Decrease**
	(s)	(t)	(u)	(v)	(w)
Residential	$0	$574,063,620	$3,089,195	$56,279,233	$0
Small General Service	$4,879,347	$0	$0	$0	$0
Medium General Service	$0	$193,655,596	$1,042,114	-$603,807	$603,807
Large General Service	$0	$125,912,174	$677,568	$13,476,991	$0
Lighting - Company	$0	$10,393,544	$55,931	$1,029,732	$0
Lighting - Customer	$0	$2,701,846	$14,539	$272,259	$0
Total Company	$4,879,347	$906,726,780	$4,879,347	$70,454,408	$603,807

Schedule 10 – Group continued – For illustrative purposes only

	ITERATION 2			
Rate Group	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenue Decrease**	**Base Distribution Revenue After Reallocation**	**Base Distribution Revenue Decrease**
	(x)	(y)	(z)	(aa)
Residential	$574,063,620	$486,099	$55,793,134	$0
Small General Service	$0	$0	$0	$0
Medium General Service	$0	$0	$0	$0
Large General Service	$125,912,174	$106,619	$13,370,372	$0
Lighting - Company	$10,393,544	$8,801	$1,020,931	$0
Lighting - Customer	$2,701,846	$2,288	$269,971	$0
Total Company	$713,071,184	$603,807	$70,454,408	$0

Rate Group	**Final Base Distribution Revenue Increase**	**Rate Group Base Distribution Revenue Target**	**Total Revenue Increase**	**Rate Group Total Revenue Target**
	(ab)	(ac)	(ad)	(ae)
Residential	$55,793,134	$574,811,310	$90,982,789	$2,173,936,393
Small General Service	$0	$223,538,825	$9,717,048	$974,847,424
Medium General Service	$0	$194,675,611	-$2,844,217	$1,004,485,957
Large General Service	$13,370,372	$119,176,117	$17,025,020	$840,043,021
Lighting - Company	$1,020,931	$9,136,287	$1,049,547	$16,078,972
Lighting - Customer	$269,971	$2,413,800	$227,124	$11,543,240
Total Company	$70,454,408	$1,123,751,951	$116,157,311	$5,020,935,007

Rate Group	Percent Increase in Distribution Revenue	Percent Increase in Total Revenue	Unit Distribution Demand Cost at EROR (per kWh or kW)
	(af)	(ag)	(ah)
Residential	10.75	4.37	$0.07051
Small General Service	-	1.01	$0.04961
Medium General Service	-	(0.28)	$15.10
Large General Service	12.64	2.07	$11.27
Lighting - Company	12.58	6.98	$0.17967
Lighting - Customer	12.59	2.01	$0.67188
Total Company	6.69	2.37	

Column definitions:

(a): Exh. ES-RDC-2, Sch 5, (Rev. 3)

(b): Exh. ES-RDC-2, Sch 5, (Rev. 3)

(c): Exh. ES-RDC-2, Sch 4, (Rev. 3) adjusted for allowed transfers and RAAF adjustment per low-income discount increase

(d): Exh. ES-ACOS-2, (Rev. 3) adjusted per Order

(e): Exh. ES-RDC-2, Sch 5 (Rev. 3) adjusted for allowed transfers and RAAF adjustment per low-income discount increase

(f): (d) – (b)

Total Revenue Cap:

(g): 10% of (a)

(h): if (e) + (f) > (g), then (e) + (f); else 0

(i): if (h) = 0, (d); else 0

(j): [total (h)] * {(i) / [total (i)]}

(k): (e) + (f) - (h) + (j)

(l): if (k) > (g), then (k) - (g); else 0

Base Distribution Revenue Cap:

(m): 200% of (b) * {[total (k)] – [total (e)]} / [total (b)]

(n): if [(k) - (e)] > (m), then [(k) - (e)] – (m); else 0

(o): if (n) = 0, then (d); else 0

(p): if (o) > 0, then [total (n)]*{p / [total (p)]}; else 0

(q): (k) – (e) - (n) + (p)

(r): if [(q) > m], then [(q) – (m)]; else 0

Base Distribution Revenue Floor:

(s): if (q) > 0, then 0; else -(q)

(t): if (s) = 0, then (d); else 0

(u): if (t) > 0, then [total (s)] * (t) / [(total (t)]

(v): (q) + (s) – (u)

(w): if (v) > 0, then 0; else -(v)

(x): if (w) = 0 AND (s) = 0, then (d); else 0

(y): if (x) > 0, then [total (w)] * (x) / [(total (x)]

(z): (v) + (w) – (y)

(aa): if (z) < 0, (z); else 0

Per Order:

(ab): (z)

(ac): (b) + (z)

(ad): (e) + (ab)

(ae): (a) + (ad)

(af): [(ab) / (b)] * 100

(ag): [(ad) / (a)] * 100

(ah): (ac) / test year kWh (residential, small C&I, streetlighting) or kW (medium C&I and large C&I)

Schedule 10 – Residential – For illustrative purposes only

Rate Class	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates	Base Rate Transfers	Unit Distribution Demand Cost at EROR (per kWh)
R-1/R-2 Residential	$1,860,455,924	$468,373,502	$(12,099,808)	$0.07051
R-3/R-4 Residential Heating	$222,497,681	$50,644,673	$(1,308,338)	$0.07051
Total Residential	$2,082,953,605	$519,018,176	$(13,408,146)	

Rate Class	Base Distribution Revenue at Group Unit Cost	Change in Reconciling Revenue	Base Distribution Revenue Increase at Group Unit Cost
R-1/R-2 Residential	$1,860,455,924	$27,470,018	$40,277,922
R-3/R-4 Residential Heating	$222,497,681	$7,719,637	$15,515,257
Total Residential	$1,860,455,924	$35,189,655	$55,793,179

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
R-1/R-2 Residential	$186,045,592	$-	$508,651,424	$985,127	$68,733,066	$0
R-3/R-4 Residential Heating	$22,249,768	$985,127	$-	$-	$22,249,768	$0
Total Residential	$208,295,360	$985,127	$508,651,424	$985,127	$90,982,834	$0

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
R-1/R-2 Residential	$62,658,470	$-	$508,651,424	$7,754,944	$49,017,993	$-
R-3/R-4 Residential Heating	$6,775,186	$7,754,944	$-	$-	$6,775,186	$-
Total Residential		$7,754,944	$508,651,424	$7,754,944	$55,793,179	$-

BASE DISTRIBUTION REVENUE FLOOR					
Rate Group	Base Distribution Revenue Decrease	Final Base Distribution Revenue Increase	Rate Group Base Distribution Revenue Target	Total Revenue Increase	Rate Group Total Revenue Target
R-1/R-2 Residential	$-	$49,017,993	$517,391,495	$76,488,010	$1,936,943,934
R-3/R-4 Residential Heating	$-	$6,775,186	$57,419,860	$14,494,824	$236,992,505
Total Residential	$-	$55,793,179	$574,811,355	$90,982,834	$2,173,936,439

Rate Group	Percent Increase in Distribution Revenue	Percent Increase in Total Revenue
R-1/R-2 Residential	10.47	4.11
R-3/R-4 Residential Heating	13.38	6.51
Total Residential	10.75	4.37

Schedule 10 – Small C&I – For illustrative purposes only

Rate Class	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates	Base Rate Transfers	Unit Distribution Demand Cost at EROR (per kWh)
G-1/T-1 (<=100 kW) (Boston Edison)	$597,554,938	$145,618,566	$(3,761,863)	$0.04961
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$45,370,801	$8,374,859	$(216,353)	$0.04961
G-5 Comm. Space Heat (Cambridge Electric Light)	$864,930	$118,103	$(3,051)	$0.04961
G-1 Gen. Serv. (Commonwealth Electric)	$189,569,184	$38,532,022	$(995,424)	$0.04961
G-7 Optional TOU (Commonwealth Electric)	$12,137,989	$2,119,466	$(54,754)	$0.04961
G-4 General Power (Commonwealth Electric)	$453,460	$83,949	$(2,169)	$0.04961
G-5 Comm. Space Heat (Commonwealth Electric)	$1,976,099	$411,198	$(10,623)	$0.04961
G-6 All Electric School (Commonwealth Electric)	$861,601	$94,725	$(2,447)	$0.04961
23 Optional Water Heating (WMA)	$12,952	$5,247	$(136)	$0.04961
24 Optional Church (WMA)	$1,004,634	$303,975	$(7,853)	$0.04961
G-1 (<=100 kW) (WMA)	$115,323,788	$27,876,714	$(720,158)	$0.04961
Total Small C&I	$965,130,376	$223,538,825	$(5,774,829)	

Rate Class	Base Distribution Revenue at Group Unit Cost	Change in Reconciling Revenue	Base Distribution Revenue Increase at Group Unit Cost
G-1/T-1 (<=100 kW) (Boston Edison)	$133,224,258	$3,058,335	$(12,394,308)
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$11,513,911	$1,326,544	$3,139,051
G-5 Comm. Space Heat (Cambridge Electric Light)	$229,098	$23,567	$110,995
G-1 Gen. Serv. (Commonwealth Electric)	$45,429,184	$3,235,565	$6,897,161
G-7 Optional TOU (Commonwealth Electric)	$3,161,495	$225,169	$1,042,029
G-4 General Power (Commonwealth Electric)	$118,265	$13,716	$34,317
G-5 Comm. Space Heat (Commonwealth Electric)	$447,650	($27,494)	$36,452
G-6 All Electric School (Commonwealth Electric)	$245,741	$59,460	$151,016
23 Optional Water Heating (WMA)	$2,605	$115	$(2,642)
24 Optional Church (WMA)	$234,306	$10,312	$(69,670)
G-1 (<=100 kW) (WMA)	$28,932,312	$1,791,760	$1,055,598
Total Small C&I	$223,538,825	$9,717,048	$0

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
G-1/T-1 (<=100 kW) (Boston Edison)	$59,755,494	$-	$133,224,258	$138,489	$(9,197,484)	$-
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$4,537,080	$-	$11,513,911	$11,969	$4,477,564	$-
G-5 Comm. Space Heat (Cambridge Electric Light)	$86,493	$48,070	$-	$-	$86,493	$-
G-1 Gen. Serv. (Commonwealth Electric)	$18,956,918	$-	$45,429,184	$47,225	$10,179,951	$-
G-7 Optional TOU (Commonwealth Electric)	$1,213,799	$53,398	$-	$-	$1,213,799	$-
G-4 General Power (Commonwealth Electric)	$45,346	$2,686	$-	$-	$45,346	$-
G-5 Comm. Space Heat (Commonwealth Electric)	$197,610	$-	$447,650	$465	$9,424	$-

G-6 All Electric School (Commonwealth Electric)	$86,160	$124,316	$-	$-	$86,160	$-
23 Optional Water Heating (WMA)	$1,295	$-	$2,605	$3	$(2,525)	$-
24 Optional Church (WMA)	$100,463	$-	$234,306	$244	$(59,114)	$-
G-1 (< =100 kW) (WMA)	$11,532,379	$-	$28,932,312	$30,076	$2,877,434	$-
Total Small C&I	$96,513,038	$228,470	$219,784,225	$228,470	$9,717,048	$-
BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distributi on Revenue Increase Greater Than 200%**
G-1/T-1 (< =100 kW) (Boston Edison)	$19,480,685	$-	$133,224,258	$3,769,018	$(8,486,801)	$-
G-1/G-6 (< =100 kW) (Cambridge Electric Light)	$1,120,379	$2,030,641	$-	$-	$1,120,379	$-
G-5 Comm. Space Heat (Cambridge Electric Light)	$15,800	$47,126	$-	$-	$15,800	$-
G-1 Gen. Serv. (Commonwealth Electric)	$5,154,770	$1,789,616	$-	$-	$5,154,770	$-
G-7 Optional TOU (Commonwealth Electric)	$283,540	$705,091	$-	$-	$283,540	$-
G-4 General Power (Commonwealth Electric)	$11,231	$20,400	$-	$-	$11,231	$-
G-5 Comm. Space Heat (Commonwealth Electric)	$55,010	$-	$447,650	$12,664	$49,582	$-
G-6 All Electric School (Commonwealth Electric)	$12,672	$14,028	$-	$-	$12,672	$-
23 Optional Water Heating (WMA)	$702	$-	$2,605	$74	$(2,566)	$-
24 Optional Church (WMA)	$40,665	$-	$234,306	$6,629	$(62,797)	$-
G-1 (< =100 kW) (WMA)	$3,729,315	$-	$28,932,312	$818,518	$1,904,192	$-
Total Small C&I	$29,904,767	$4,606,902	$162,841,131	$4,606,902	$0	$-

BASE DISTRIBUTION REVENUE FLOOR		
Rate Group	**Base Distribution Revenue Decrease**	Since there is no change to the current distribution revenue for the entire group, revenue floor iterations would continue until each rate class received no change in base distribution revenues.
G-1/T-1 (<=100 kW) (Boston Edison)	$-	
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$-	
G-5 Comm. Space Heat (Cambridge Electric Light)	$-	
G-1 Gen. Serv. (Commonwealth Electric)	$-	
G-7 Optional TOU (Commonwealth Electric)	$-	
G-4 General Power (Commonwealth Electric)	$-	
G-5 Comm. Space Heat (Commonwealth Electric)	$-	
G-6 All Electric School (Commonwealth Electric)	$(43,619)	
23 Optional Water Heating (WMA)	$-	
24 Optional Church (WMA)	$-	
G-1 (<=100 kW) (WMA)	$-	
Total Small C&I	$(43,619)	

Rate Group	Final Base Distribution Revenue Increase	Rate Group Base Distribution Revenue Target	Total Revenue Increase	Rate Group Total Revenue Target	Percent Increase in Distribution Revenue	Percent Increase in Total Revenue
G-1/T-1 (<=100 kW) (Boston Edison)	$-	$145,618,566	$3,058,335	$600,613,273	-	0.51
G-1/G-6 (<=100 kW) (Cambridge Electric Light)	$-	$8,374,859	$1,326,544	$46,697,344	-	2.92
G-5 Comm. Space Heat (Cambridge Electric Light)	$-	$118,103	$23,567	$888,498	-	2.72
G-1 Gen. Serv. (Commonwealth Electric)	$-	$38,532,022	$3,235,565	$192,804,749	-	1.71
G-7 Optional TOU (Commonwealth Electric)	$-	$2,119,466	$225,169	$12,363,158	-	1.86
G-4 General Power (Commonwealth Electric)	$-	$83,949	$13,716	$467,176	-	3.02
G-5 Comm. Space Heat (Commonwealth Electric)	$-	$411,198	$(27,494)	$1,948,605	-	(1.39)
G-6 All Electric School (Commonwealth Electric)	$-	$94,725	$59,460	$921,061	-	6.90
23 Optional Water Heating (WMA)	$-	$5,247	$115	$13,066	-	0.89

24 Optional Church (WMA)	$-	$303,975	$10,312	$1,014,945	-	1.03
G-1 (<=100 kW) (WMA)	$-	$27,876,714	$1,791,760	$117,115,549	-	1.55
Total Small C&I	$-	$223,538,825	$9,717,048	$974,847,424	-	1.01

Schedule 10 – Medium C&I – For illustrative purposes only

Rate Class	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates	Base Rate Transfers	Unit Distribution Demand Cost at EROR (per kW)
G-2 TOU (Boston Edison)	$773,206,844	$160,011,887	$(4,133,695)	$15.10
G-2 TOU (Cambridge Electric Light)	$99,209,689	$13,658,395	$(352,847)	$15.10
G-2 TOU (Commonwealth Electric)	$72,882,017	$10,357,394	$(267,570)	$15.10
G-2/T4 (WMA)	$62,031,623	$10,647,936	$(275,075)	$15.10
Total Medium C&I	$1,007,330,174	$194,675,611	$(5,029,186)	

Rate Class	Base Distribution Revenue at Group Unit Cost	Change in Reconciling Revenue	Base Distribution Revenue Increase at Group Unit Cost
G-2 TOU (Boston Edison)	$142,147,912	($7,471,813)	$(17,863,975)
G-2 TOU (Cambridge Electric Light)	$20,131,914	$2,745,488	$6,473,519
G-2 TOU (Commonwealth Electric)	$17,171,062	$1,669,464	$6,813,668
G-2/T4 (WMA)	$15,224,724	$212,644	$4,576,788
Total Medium C&I	$194,675,611	$(2,844,217)	$0

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
G-2 TOU (Boston Edison)	$77,320,684	$-	$142,147,912	$956,916	$(24,378,872)	$-
G-2 TOU (Cambridge Electric Light)	$9,920,969	$-	$20,131,914	$135,525	$9,354,532	$-
G-2 TOU (Commonwealth Electric)	$7,288,202	$1,194,931	$-	$-	$7,288,202	$-
G-2/T4 (WMA)	$6,203,162	$-	$15,224,724	$102,490	$4,891,922	$-

Total Medium C&I	$100,733,017	$1,194,931	$177,504,550	$1,194,931	$(2,844,217)	$-

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
G-2 TOU (Boston Edison)	$21,406,207	$-	$142,147,912	$12,269,786	$(4,637,273)	$-
G-2 TOU (Cambridge Electric Light)	$1,827,204	$4,781,840	$-	$-	$1,827,204	$-
G-2 TOU (Commonwealth Electric)	$1,385,600	$4,233,137	$-	$-	$1,385,600	$-
G-2/T4 (WMA)	$1,424,469	$3,254,810	$-	$-	$1,424,469	$-
Total Medium C&I	$26,043,480	$12,269,786	$142,147,912	$12,269,786	$0	$-

BASE DISTRIBUTION REVENUE FLOOR		
Rate Group	**Base Distribution Revenue Decrease**	Since there is no change to the current distribution revenue for the entire group, revenue floor iterations would continue until each rate class received no change in base distribution revenues.
G-2 TOU (Boston Edison)	$(4,637,273)	
G-2 TOU (Cambridge Electric Light)	$-	
G-2 TOU (Commonwealth Electric)	$-	
G-2/T4 (WMA)	$-	
Total Medium C&I	$(4,637,273)	

Rate Group	**Final Base Distribution Revenue Increase**	**Rate Group Base Distribution Revenue Target**	**Total Revenue Increase**	**Rate Group Total Revenue Target**	**Percent Increase in Distribution Revenue**	**Percent Increase in Total Revenue**
G-2 TOU (Boston Edison)	$-	$160,011,887	$(7,471,813)	$765,735,032	-	(0.97)
G-2 TOU (Cambridge Electric Light)	$-	$13,658,395	$2,745,488	$101,955,177	-	2.77

G-2 TOU (Commonwealth Electric)	$-	$10,357,394	$1,669,464	$74,551,481	-	2.29
G-2/T4 (WMA)	$-	$10,647,936	$212,644	$62,244,267	-	0.34
Total Medium C&I	$-	$194,675,611	$(2,844,217)	$1,004,485,957	-	(0.28)

Schedule 10 – Large C&I – For illustrative purposes only

Rate Class	Total Revenue at Current Rates	Base Distribution Revenue at Current Rates	Base Rate Transfers	Unit Distribution Demand Cost at EROR (per kW)
Rate G-3 TOU (Boston Edison)	$476,406,008	$70,293,999	$(1,815,952)	$11.27
Rate WR (Boston Edison)	$15,594,462	$1,806	$(47)	
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$97,910,318	$8,201,486	$(211,875)	$11.27
Rate G-3 TOU (Commonwealth Electric)	$69,184,332	$6,863,136	$(177,300)	$11.27
Rate G-3 TOU (WMA)	$105,722,954	$14,976,652	$(386,902)	$11.27
Rate T-5 TOU (WMA)	$58,199,925	$5,468,667	$(141,276)	$11.27
Total Large C&I	$823,018,000	$105,805,745	$(2,733,351)	

Rate Class	Base Distribution Revenue at Group Unit Cost	Change in Reconciling Revenue	Base Distribution Revenue Increase at Group Unit Cost
Rate G-3 TOU (Boston Edison)	$65,326,833	-$2,036,435	-$4,968,971
Rate WR (Boston Edison)		-$83,047	
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$15,639,075	$2,146,030	$7,437,589
Rate G-3 TOU (Commonwealth Electric)	$12,013,668	$1,411,501	$5,150,532
Rate G-3 TOU (WMA)	$17,368,563	$387,012	$2,391,912
Rate T-5 TOU (WMA)	$8,827,991	$1,829,587	$3,359,324
Total Large C&I	$119,176,130	$3,654,648	$13,370,386

TOTAL REVENUE CAP						
	ITERATION 1					
Rate Class	**10% Total Revenue Cap**	**Total Revenue Increase Greater Than 10%**	**Base Distribution Revenue Allocator**	**Allocation of Revenues Greater Than 10%**	**Total Revenue Increase After Reallocation**	**Total Revenue Increase Greater Than 10%**
Rate G-3 TOU (Boston Edison)	$47,640,601	$0	$65,326,833	$0	-$7,005,406	$0
Rate WR (Boston Edison)	$1,559,446	$0	$0	$0	-$83,047	$0

Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$9,791,032	$0	$15,639,075	$0	$9,583,619	$0
Rate G-3 TOU (Commonwealth Electric)	$6,918,433	$0	$12,013,668	$0	$6,562,033	$0
Rate G-3 TOU (WMA)	$10,572,295	$0	$17,368,563	$0	$2,778,923	$0
Rate T-5 TOU (WMA)	$5,819,992	$0	$8,827,991	$0	$5,188,912	$0
Total Large C&I	$82,301,800	$0	$119,176,130	$0	$17,025,034	$0

BASE DISTRIBUTION REVENUE CAP						
	ITERATION 1					
Rate Class	**200% Base Distribution Revenue Increase Cap**	**Base Distribution Revenue Increase Greater Than 200%**	**Base Distribution Revenue Allocator**	**Allocation of Base Distribution Revenues Greater Than 200%**	**Base Distribution Revenue Increase After Reallocation**	**Base Distribution Revenue Increase Greater Than 200%**
Rate G-3 TOU (Boston Edison)	$9,403,850	$0	$65,326,833	$13,588,878	$8,619,906	$0
Rate WR (Boston Edison)	$242	$0	$0	$0	$0	$0
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$1,097,185	$6,340,404	$0	$0	$1,097,185	$0
Rate G-3 TOU (Commonwealth Electric)	$918,142	$4,232,390	$0	$0	$918,142	$0
Rate G-3 TOU (WMA)	$2,003,559	$388,352	$0	$0	$2,003,559	$0
Rate T-5 TOU (WMA)	$731,592	$2,627,732	$0	$0	$731,592	$0
Total Large C&I	$14,154,571	$13,588,878	$65,326,833	$13,588,878	$13,370,386	$0

BASE DISTRIBUTION REVENUE FLOOR					
Rate Group	**Base Distribution Revenue Decrease**	**Final Base Distribution Revenue Increase**	**Rate Group Base Distribution Revenue Target**	**Total Revenue Increase**	**Rate Group Total Revenue Target**
Rate G-3 TOU (Boston Edison)	$0	$8,619,906	$78,913,905	$6,583,472	$482,989,480
Rate WR (Boston Edison)	$0	$0	$1,806	-$83,047	$15,511,416
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	$0	$1,097,185	$9,298,671	$3,243,215	$101,153,534
Rate G-3 TOU (Commonwealth Electric)	$0	$918,142	$7,781,279	$2,329,643	$71,513,975
Rate G-3 TOU (WMA)	$0	$2,003,559	$16,980,211	$2,390,571	$108,113,526
Rate T-5 TOU (WMA)	$0	$731,592	$6,200,259	$2,561,179	$60,761,104
Total Large C&I	$0	$13,370,386	$119,176,130	$17,025,034	$840,043,034

Rate Group	Percent Increase in Distribution Revenue	Percent Increase in Total Revenue
Rate G-3 TOU (Boston Edison)	12.26	1.38
Rate WR (Boston Edison)	-	(0.53)
Rate G-3/SB1/MS1/SS1 (Cambridge Electric Light)	13.38	3.31
Rate G-3 TOU (Commonwealth Electric)	13.38	3.37
Rate G-3 TOU (WMA)	13.38	2.26
Rate T-5 TOU (WMA)	13.38	4.40
Total Large C&I	12.64	2.07

XX. ORDER

Accordingly, after due notice, hearing, opportunity for comment, and consideration, it is

ORDERED: That the tariffs filed by NSTAR Electric Company on January 14, 2022, to become effective February 1, 2022, are DISALLOWED; and it is

FURTHER ORDERED: That NSTAR Electric Company shall file new schedules of rates and charges designed to collect the cost of service as set forth in the Schedules above; and it is

FURTHER ORDERED: That NSTAR Electric 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 NSTAR Electric Company shall comply with all other directives contained in this Order; and it is

<u>FURTHER ORDERED</u>: That the new rates shall apply to electricity consumed on or after January 1, 2023, 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,

Matthew H. Nelson, Chair

Robert E. Hayden, Commissioner

Cecile M. Fraser, 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.