The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

September 30, 2024

D.P.U. 23-150

Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, 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, a Performance-Based Ratemaking Plan, and a Capital Recovery Mechanism.

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SUMMARY

The Department of Public Utilities ("Department") issues this Order addressing the petition filed by Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid ("National Grid" or "Company") on November 16, 2023, seeking an increase in electric base distribution rates. Pursuant to G.L. c. 164, § 94, the Department conducted an intensive ten-month investigation of the Company's petition, which included reviewing and evaluating National Grid's annual revenues and expenses; current and proposed cost-recovery mechanisms; residential and commercial and industrial rate design; and capital structure and return on equity. To facilitate our investigation, the Department required the parties to submit written testimony; gathered evidence through written discovery; held eight public hearings to receive public comments; conducted twelve days of evidentiary hearings to cross-examine witnesses and collect additional information; and weighed the parties' arguments submitted through legal briefs. As noted in our decision below, the evidentiary record in these proceedings includes approximately 2,500 exhibits.

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

As part of today's decision to allow an electric rate increase, the Department reduces the Company's initially requested revenue deficiency by approximately 40 percent. This reduction includes lowering the Company's requested return on equity from 10.50 percent to 9.35 percent.

The Department also recognizes the disproportionate impact of high electricity bills on low-income customers. As such, the Department approves with modifications the Company's proposal to implement a five-tiered discount for qualifying electric income-eligible customers ranging from a discount of 32 percent to 71 percent, which does not require a customer to receive Low-Income Home Energy Assistance Program benefits. The discount structure is designed to offer higher discounts to customers at lower income levels, and to assist the spectrum of income-eligible customers in managing their electric energy burden. The Department also allows the Company, in a future filing, to seek costs associated with the hiring of additional employees as part of expanded education, outreach, and verification efforts to increase enrollment of eligible customers into the discount program. The Department also directs the Company to establish a two-year self-attestation pilot for customers to demonstrate eligibility for the discount offering. Resources are available for customers having difficulty paying their utility bills. Please visit: https://www.mass.gov/info-details/help-paying-your-utility-bill.

The Department supports customer conversion to electrified and decarbonized heating technologies, including heat pumps. The Company proposed a heating electrification pricing option for Rate R-1 that the Department rejects. Instead, the Department directs the Company to submit for approval a residential heat-pump rate available to all customers in rate classes R-1 and R-2 who install and use heat pumps in all or part of their homes similar to a heat-pump rate

approved for Fitchburg Gas and Electric Light Company. The heat pump rate offerings will reduce the variable kilowatt hour rate associated with electric use during the winter when heat pumps would result in increased electricity use to replace traditional fossil fuel heating equipment. The Company's heat-pump rate will be a reasonable, cost-efficient solution to assist in the reduction of greenhouse gas emissions and encourage non-emitting renewable sources of energy. The Department directs the Company to engage in meaningful outreach and education efforts to raise awareness of the heat-pump rate option once it is approved.

The Department recognizes the importance of establishing a regulatory paradigm that enables utilities to navigate the Commonwealth's transition to clean energy in a cost-effective manner that provides significant benefits to customers. In today's Order, the Department approves a five-year performance-based ratemaking ("PBR") plan relative to the Company's operations and maintenance expenses. The plan is intended to incentivize the Company to identify and implement operating efficiencies to minimize future cost increases to customers. As part of the plan, the Company agrees not to a file a petition that seeks to increase base distribution rates during the five-year term. To measure progress towards the objectives of the PBR plan, the Department approves a set of performance scorecard metrics in the following categories, which are tied to the goals of the PBR and consistent with the Department's regulatory objectives: (1) improvements to customer service and engagement; (2) reductions in greenhouse gas emissions; and (3) enrollment in clean energy programs.

Over the next five years, the Company expects to complete capital projects designed to protect and improve the electric delivery system by repairing failed or damaged equipment, addressing load growth and migration, sustaining system viability through targeted capital investments driven primarily by asset condition, and maintaining a continuing level of inspection and maintenance. The Department approves a cost recovery mechanism for core investments, planned investments to maintain the safety and reliability of the electric distribution system, to provide the Company with necessary funding to complete these important tasks, but with cost control and prudency measures to ensure that customers are protected from over- or mis-investment.

The Department also approves two performance incentive mechanisms that are designed to create new benefits and value for customers based on the Company's targeted achievement of specific policy goals or outcomes. The performance incentive mechanisms will measure the Company's efforts to enroll new customers in the enhanced low-income discount program discussed above, as well as the Company's rate of deployment of solar and storage projects interconnected to the distribution system to support the Commonwealth's clean energy transition. The performance incentive mechanisms are symmetrical, such that the Company is rewarded for exceptional performance and penalized if it fails to deliver results above a target range.

Under even normal operations, it is essential that utilities maintain a safe and reliable distribution system. As the Commonwealth moves toward electrification, there is heightened scrutiny on the ability of the distribution system to deliver for customers. To that end, the Department reviewed and modified, as necessary, the Company's vegetation management program, which is designed to reduce outages during storms by minimizing the potential for tree and vegetation contact with overhead utility lines and reducing tree exposure along select circuits. The Department also made changes to the Company's storm cost recovery mechanism to provide necessary resources to ensure safe and timely service restoration following major storm events.

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

I. INTRODUCTION

On November 16, 2023, Massachusetts Electric Company ("MECo") and Nantucket Electric Company ("Nantucket Electric"), each doing business as National Grid ("National Grid" or "Company"), filed a petition with the Department to increase its electric base distribution rates to generate $131,232,856 in additional base distribution revenues. Based on changes made during the proceeding, the Company's total proposed revenue deficiency decreased to $118,277,373 (Exh. NG-RRP-7, at 1 (Rev. 4)).[1, 2]

In addition to the requested rate increase, National Grid seeks approval of a five-year performance-based ratemaking ("PBR") plan applicable to operation and maintenance ("O&M") expenses ("PBR-O"), a new reconciling mechanism to recover capital costs and certain expenses, and numerous other ratemaking proposals as discussed in the sections below. National Grid bases its proposed base distribution rate increase on a twelve-month test year of April 1, 2022 through March 31, 2023. The Company was last granted an increase in electric base distribution rates in 2019. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 18-150 (2019). The Department docketed the instant petition as D.P.U. 23-150 and suspended the effective date of the proposed rate increase until October 1, 2024, for further investigation. The Company requests approval for new rates approved in this proceeding,

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1 The Company proposed to transfer costs recovered through certain reconciling mechanisms, along with associated income taxes, which results in an increase of $389,766 to distribution revenues, effective October 1, 2024 (see Exh. NG-RRP-2, Sch. 1, at 1). Based on these proposals, the initially proposed overall increase to distribution revenues was $131,622,621. Schedule 1 below provides the Company's initially requested, adjusted, and final approved revenue requirement.

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

though effective October 1, 2024, to be implemented and billed beginning on November 1, 2024 (Exh. NG-PP-1, at 48).[3]

National Grid is engaged in the retail distribution and sale of electricity in Massachusetts across a service territory that spans approximately 4,625 square miles in 172 cities and towns (Exh. NG-MECO-1, at 8). The Company serves approximately 1.3 million customers (Exh. NG-MECO-1, at 8). MECo and Nantucket Electric are wholly owned subsidiaries of National Grid USA, which is an indirect wholly owned subsidiary of National Grid plc, a public limited company incorporated under the laws of England and Wales (Exhs. NG-MECO-1, at 8; AG 1-98, Att.). National Grid plc owns and operates electricity transmission and gas transmission and distribution networks in the United Kingdom (Exh. NG-MECO-1, at 8). In addition to MECo and Nantucket Electric, National Grid USA also owns affiliated electric and gas distribution companies operating in New York and an affiliated gas distribution company operating in Massachusetts (Exh. NG-MECO-1, at 8). Additionally, National Grid USA owns National Grid USA Service Company ("NGSC"), which provides executive and administrative, legal, financial, engineering, human resources, information systems, shared services, and other services to National Grid USA subsidiaries, including MECo and Nantucket Electric (Exhs. NG-MECO-1, at 1, NG-RRP-1, at 1; AG 1-26, Att. 2, at 41-42; AG 1-98, Att. at 2). As

[3] National Grid states that its proposal to implement new rates on November 1, 2024, will provide sufficient time to complete the compliance phase of this proceeding, and the Company can avoid having to hold October bills for a late-month issuance (Exh. NG-PP-1, at 48-50). On this latter point, the Company notes that issuing a late October bill followed by a November bill would create customer confusion and dissatisfaction (Exh. NG-PP-1, at 49-50). The Company proposes to recover the incremental base distribution revenue accrued for October through the revenue decoupling adjustment factors (Exh. NG-PP-1, at 50).

discussed below in this Order, on May 25, 2022, National Grid USA finalized the sale of its electric and natural gas distribution company operating in Rhode Island, The Narragansett Electric Company ("Narragansett Electric"), to PPL Rhode Island Holdings, LLC ("PPL Rhode Island"), a subsidiary of PPL Corporation (collectively, "Rhode Island Sale") (Exh. NG-JR-1, at 2, 5).

II. PROCEDURAL HISTORY

On November 17, 2023, the Attorney General filed a notice of intervention pursuant to G.L. c. 12, § 11E(a). Subsequently, the Department granted full-party intervenor status to the following: Massachusetts Department of Energy Resources ("DOER"); Low-Income Weatherization and Fuel Assistance Program Network and the Low-Income Energy Affordability Network ("LEAN") (together "Low-Income Network"); Acadia Center; Conservation Law Foundation ("CLF"); The Energy Consortium ("TEC"); Environmental Defense Fund ("EDF"); Massachusetts Energy Directors Association ("MEDA"); New England Connectivity and Telecommunications Association ("NECTA"); PowerOptions, Inc. ("PowerOptions"); and Solar Energy Industries Association ("SEIA").

Pursuant to notice duly issued, the Department held the following in-person public hearings in the Company's service area: (1) Lawrence on March 12, 2024; (2) Brockton on March 14, 2024; (3) Quincy on March 19, 2024; (4) Worcester on April 3, 2024; and (5) Great Barrington on April 9, 2024. The Department held two virtual public hearings on March 21, 2004 (afternoon and evening session) and one virtual public hearing on May 2, 2024.[4]

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4 The Department scheduled an in-person public hearing for April 4, 2024, in Nantucket, but the hearing was postponed due to inclement weather. D.P.U. 23-150, Notice of

The Department received written comments and comments at the public hearings from residents and elected officials concerning the Company's petition. Commenters expressed frustration with the increasing cost of electricity, shared personal hardships associated with high residential energy bills, and noted the difficulty in reducing their energy burden despite best efforts. Some also expressed concerns with the Company's customer communications, service, and reliability. Several commenters expressed some support for the Company's proposed rate increase if the additional revenues would support the Commonwealth's climate transition objectives or improve reliability. The majority of comments, however, were opposed to National Grid's proposals.[5] The Department appreciates the thoughtful comments provided by the Company's customers and their representatives. The Department will address any specific comments, as necessary, in the sections below.

The Department held twelve days of evidentiary hearings from May 6, 2024 through May 29, 2024. In support of its filings, National Grid sponsored the testimony of the following witnesses: (1) Lisa Spangenberg Wieland, president, National Grid New England, NGSC; (2) Nicola Medalova, chief operating officer, electric, NGSC; (3) Sandy Grace, vice president, U.S. policy and regulatory strategy, NGSC; (4) Andrew Gumbus, director, revenue requirements, NGSC; (5) Dr. Mark E. Meitzen, senior consultant, Christensen Associates; (6) Nicholas A.

Postponement of Public Hearing (April 4, 2024); D.P.U. 23-150, Notice of Filing and Public Hearings at 5 (December 15, 2023). The Department rescheduled the hearing as a virtual hearing held on May 2, 2024. D.P.U. 23-150, Notice of Filing and Rescheduled Public Hearing (Nantucket) at 5 (April 11, 2024).

5 Walmart, Inc., which was denied intervenor and limited participant status in this proceeding, provided comments addressing a number of the Company's proposals.

Crowley, senior economist, Christensen Associates; (7) Dr. Lawrence R. Kaufmann, president, Kaufmann Consulting; (8) Kathleen M. Hammer, interim manager, National Grid rate case, Massachusetts revenue requirements department, NGSC; (9) Daniel S. Dane, president, Concentric Energy Advisors, Inc. ("Concentric"); (10) Bertram H. Stewart, III, manager, vegetation strategy, NGSC; (11) Ryan A. Moe, lead specialist, vegetation strategy, NGSC; (12) James Reynolds, director, finance business partner, Rhode Island transition services agreement and Massachusetts Attorney General settlement, NGSC; (13) Ann E. Bulkley, principal, The Brattle Group; (14) Jonathan Berry, vice president, electric information technology delivery, NGSC; (15) Dennis McDermitt, vice president, cybersecurity and U.S. chief information security officer, NGSC; (16) Daniel J. DeMauro, Jr., consultant; (17) Maureen P. Heaphy, vice president, global benefits, NGSC; (18) Roberta Burcham, manager, global compensation, NGSC; (19) Brian J. McNaughton, director, New England electric investment management and operation controls, NGSC; (20) Ned W. Allis, vice president, Gannett Fleming Valuation and Rate Consultants, LLC; (21) Melissa A. Little, director, Massachusetts pricing, NGSC; (22) Howard S. Gorman, president, HSG Group, Inc.; (23) Morgan Steacy, vice president, account management, NGSC; (24) Rasheeda Davis, director, market segmentation and growth, NGSC; (25) Karsten Barde, director, U.S. policy and regulatory strategy, NGSC; (26) Lauri Mancinelli, principal analyst, regulatory strategy, NGSC; (27) Jeffrey Koenig, director, credit and collections and payment processing, NGSC; (28) Candace Poudrier, senior customer advocate, NGSC; (29) Robert Andrew Schneller, vice president, New England electric regulatory and strategy; (30) Elton Prifti, director, New England distribution asset management and planning, NGSC; (31) Vishal Ahirrao, director, customer energy integration, NGSC; (32) Fred Daum, vice president, contact centers, NGSC; (33) Brian Schiavone, asset management and engineering, U.S. fleet, NGSC; (34) Madeline Gothie, director, U.S. pension delivery, NGSC; (35) Joy Banks, manager, third-party attachments and outdoor lighting, NGSC; and (36) Brian J. McNaughton, director, New England investment planning and portfolio development, NGSC.

The Attorney General sponsored the testimony of the following witnesses: (1) J. Randall Woolridge, Ph.D., professor of finance, Pennsylvania State University; (2) David E. Dismukes, Ph.D., consulting economist, Acadian Consulting Group; (3) David J. Garrett, managing member, Resolve Utility Consulting, PLLC; (4) Lafayette K. Morgan, senior consultant, Exeter Associates, Inc.; (5) Paul Alvarez, president, Wired Group; (6) Dennis Stephens, consultant; (7) John Defever, C.P.A., senior regulatory consultant, Larkin & Associates, PLLC; (8) Ronald Nelson, president, Volt-Watt Consulting LLC; (9) Caroline Palmer, senior manager, Strategen Consulting; and (10) Courtney E. Henderson, president, Hawks Peak Strategies, Inc.

DOER sponsored the testimony of Melissa Whited, vice president, Synapse Energy Economics. CLF and EDF jointly sponsored the testimony of Joshua R. Castigliego, researcher, Applied Economics Clinic, and Mary Wambui, a member of the Energy Efficiency Advisory Council, an energy advocate, and resident of Lowell. TEC and PowerOptions jointly sponsored the testimony of James D. Bride, principal, Energy Tariff Experts, LLC., and Alexa Nutter, consultant, Energy Tariff Experts, LLC. MEDA sponsored the testimony of John Howat, senior policy analyst, National Consumer Law Center.

On June 21, 2024, the Department received initial briefs from the Attorney General; DOER; the Low-Income Network; Acadia Center; CLF; TEC and PowerOptions (jointly); EDF;

MEDA; NECTA; and SEIA. On the same day, NECTA filed a "Motion to File Documents Subsequent to Hearing" in support of issues raised in NECTA's initial brief. On June 28, 2024, the Company filed an objection to NECTA's motion.[6] On the same day, the Attorney General filed a Motion to Reopen the Proceedings and Correct the Record, a revised Exhibit AG-RNCP-1 to correct certain numbers, and a revised initial brief to correct the same numbers.[7] On July 9, 2024, the Company filed an initial brief. The next day, the Company filed a revised initial brief to correct formatting issues.[8]

On July 15, 2024, the Company filed a Motion to Reopen the Evidentiary Record for the limited purpose of submitting additional testimony and documentary information on certain financial accounting considerations relating to the Company's pension and post-retirement benefits other than pension ("PBOP") costs. On July 17, 2024, the Department issued a Memorandum allowing National Grid to file additional evidence (e.g., testimony, supporting documentation) as set forth in the Company's motion. On July 18, 2024, the Attorney General filed a response to National Grid's motion and sought additional process on the Company's forthcoming evidence.

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6 NECTA's motion is discussed further in n.265 below.

7 There are no other changes to Exhibit AG-RNCP-1 or the Attorney General's initial brief, including any changes to pagination. No party objected to the Attorney General's motion. The motion is allowed. Given the discrete changes to the initial and revised filings, the Department does not distinguish between the initial and revised when citing to these documents. To the extent the Department refers to the subject numbers, we cite to those in the corrected version of the testimony and initial brief.

8 All citations herein are to the Company's revised brief. For administrative ease, the Department does not include "(Rev.)" after the cites.

On July 23, 2024, the Department received reply briefs from the Attorney General; DOER; the Low-Income Network; Acadia Center, CLF, and EDF (jointly); TEC and PowerOptions (jointly); MEDA; and NECTA. On July 24, 2024, the Company filed testimony and supporting documentation in response to the Department's July 17, 2024 Memorandum.[9] On July 25, 2024, the Department issued a second Memorandum and allowed a discovery and briefing phase concerning the Company's additional pension and PBOP evidence.

On July 30, 2024, the Company filed a reply brief. On August 14, 2024, the Company and the Attorney General submitted briefs regarding the additional pension and PBOP evidence. The evidentiary record consists of approximately 1,770 exhibits comprising testimony and documentary evidence submitted by the Company and intervenors, responses to more than 650 information requests, and responses to 86 record requests issued at the evidentiary hearings.

III. COMPANY'S USE OF A SPLIT TEST YEAR

A. Introduction

The revenue requirement component of the Company's filing is based on a test year ending March 31, 2023, representing a non-calendar or split test year (Exh. NG-RRP-1, at 8).[10]

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9 Specifically, the Company filed joint testimony from Andrew Gumbus and Madeline Gothie, marked as Exhibit NG-P/PBOP-1; two supporting documents marked as Exhibits NG-P/PBOP-2 and NG-P/PBOP-3; and testimony from Michael F. Farrell, a senior director in Willis Towers Watson's retirement practice, marked as Exhibit NG-P/PBOP-4. Pursuant to 220 CMR 1.10, the Department moves into the evidentiary record of this proceeding the four exhibits.

10 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. NSTAR Gas Company, D.P.U. 14-150, at 45 n.26 (2015); Plymouth Water Company, D.P.U. 14-120, at 12, 16 (2015). A test year, whether a calendar-year test year or a split test year, comprises a period of twelve consecutive calendar months.

In support of its proposed test year, the Company provided balance sheets based on data as of March 31, 2023, along with income statements and electric O&M expense statements based on data as of March 31, 2023, in the filing format used by the Federal Energy Regulatory Commission ("FERC") (Exhs. NG-RRP-1, at 12; WP NG-RRP-1a at 2-12; WP NG-RRP-1b at 1-12). The Company also provided its quarterly FERC Form 3-Q reports for the period from March 2021 through June 2023 (Filing Requirements, Section III.B.2a, Atts. 1 through 16). In addition, the Company provided audited financial statements for the fiscal years ended March 31, 2021, March 31, 2022, and March 31, 2023, consisting of income statements, cash flow statements, earned surplus statements, and shareholder equity statements (Exhs. NG-RRP-1, at 9; WP NG-RRP-1c at 5-9, 49-53). The audited financial statements include the recognition of accruals booked to reserve accounts and end-of-period reconciliations for those account balances (Exhs. NG-RRP-1, at 9-10; DPU 2-1, Atts. 1 through 3; DPU 2-2, Atts. 1 through 7). Finally, the Company provided a reconciliation of key income and balance sheet accounts to its audited financial statements (Exhs. NG-RRP-1, at 10; WP NG-RRP-1a at 1). None of the parties addressed the Company's proposed test year on brief.

B. Analysis and Findings

It is well-established Department precedent that base rate filings are based on a historical 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 historical test year represent a twelve-month period that does not overlap with the test year used in a previous base distribution 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 (1978).

Although the Department on occasion has accepted a non-calendar test year, we also have recognized that there are significant complications associated with the use of a split test year that can call into question the use of such data to establish rates. D.P.U. 14-120, at 10; AT&T Communications of New England, Inc., D.P.U. 90-133-A at 5-6 (1991). For example, test-year amounts associated with a split test year will not tie back to amounts included in the annual returns submitted to the Department, which are prepared on a calendar-year basis. NSTAR Electric Company and Western Massachusetts Electric Company, D.P.U. 17-05, at 23 (2017);

Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-155, at 14-15 (2016); D.P.U. 14-120, at 11. The use of a split test year also limits the Department's ability to review year-to-year changes in expense levels. D.P.U. 17-05, at 23; D.P.U. 15-155, at 15; D.P.U. 14-120, at 11. This limitation is of significant concern to the Department because reliance on a split test year may create an improper incentive for utilities to book expenses into a certain period for purposes of creating an inflated test-year expense. D.P.U. 17-05, at 23-24; D.P.U. 15-155, at 15; D.P.U. 14-120, at 11. Another complication associated with use of a split test year involves year-end accounting for accrued revenues and expenses which, if not properly recognized in the rate-setting process, may result in a distorted measurement of net operations. D.P.U. 17-05, at 24; D.P.U. 15-155, at 15; D.P.U. 14-120, at 11, citing The Berkshire Gas Company, D.P.U. 1490, at 35-37 (1983).

The Department has noted that any decision to rely on a non-calendar test year will carry with it a high burden for a company to demonstrate that its proposed rates are just and reasonable. D.P.U. 17-05, at 24; D.P.U. 15-155, at 15-16; D.P.U. 14-120, at 12. Specifically, any company that seeks to rely on a split test year, as a threshold matter, must demonstrate by clear and convincing evidence that its proposed test year is reviewable and reliable and represents a full accounting of the company's operations for the period. D.P.U. 17-05, at 24-35; D.P.U. 15-155, at 16; D.P.U. 14-120, at 16; see also Blackstone Gas Company, D.P.U. 19579, at 2-4 (1978); Cape Cod Gas Company/Lowell Gas Company, D.P.U. 18571/18572, at 4-14 (1976).

Further, at a minimum, a company that proposes to use a split test year must be prepared to make a threshold showing:

1) how its test-year account balances tie back to the account balances as reported in the annual returns;

2) that the amounts have been properly audited (or, in the case of a small water company that is not a subsidiary of a publicly traded entity, otherwise verified) and are available for review;

3) that a meaningful year-to-year review of changes in expense levels and revenues is possible, such that the Department can determine whether the company's test-year expenses and revenues are representative of its ongoing costs and revenues, are reasonable in amount, and account for any seasonal variability; and

4) that the company has properly recognized accruals booked to reserve accounts, including any end-of-period reconciliations of those account balances.

D.P.U. 17-05, at 25; D.P.U. 15-155, at 16; D.P.U. 14-120, at 6 n.11.

Based on our review of National Grid's filing and the account level detail provided by the Company, we find that it is possible to tie the Company's test-year account balances back to the account balances as reported in its annual returns. Boston Gas Company, D.P.U. 20-120, at 14-17 (2021). First, the Company provided balance sheets, income statements, statements of earned surplus, and electric O&M expense schedules corresponding to those same schedules provided in the annual returns to the Department, incorporating data as of March 31, 2022, and March 31, 2023 (Exhs. NG-RRP-1, at 9; WP NG-RRP-1c at 5-9, 49-53). This information is supported by the Company's FERC Form 3-Q reports, which provide quarterly balance sheets and income statements from the first quarter of 2021 through the second quarter of 2023 (Filing Requirements, Section III.B.2a, Atts. 1 through 16). The Company also has provided documentation mapping the accounts maintained in its internal accounting system to the accounts reported in the annual returns to the Department (Exh. DPU 2-3, Att.).[11] The Department has examined this documentation and is satisfied that the information is sufficient to tie the Company's test-year account balances back to its annual returns.

Further, the Company's audited financial statements prepared by Deloitte are based on the Company's fiscal year ending March 31, which corresponds to the March 31, 2023 test-year end proposed here (Exh. WP NG-RRP-1c). On this basis, the Department finds that the audited financial statements provide an independent and extensive review of the Company's test-year cost of service data. In reaching this finding, the Department notes that financial audits are designed to show whether the subject of the audit has properly prepared its financial statements to be free of material misstatements and to express an opinion on the subject's internal controls. While audited financial statements are of considerable assistance in the ratemaking process, an audit does not establish either the reasonableness of the reported costs or the ratemaking treatment to be accorded to such costs. Boston Edison Company, D.P.U./D.T.E. 97-95, at 77 (2001); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 4240, Introductory Letter (May 19, 1941). See also Boston Gas Company v. City of Newton, 425 Mass. 697, 706 (1997); Reclassification of Accounts of Gas and Electric Companies, D.P.U. 106, Introductory Letter (May 27, 1921). The Department will evaluate the reasonableness of costs and appropriate ratemaking treatment in this Order.

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11 The Company's internal account numbers are based on an alphanumeric system of "natural accounts" (i.e., groupings of various accounts by function) (Exh. DPU 2-3). These natural accounts track FERC's Uniform System of Accounts for Electric Companies, with the addition of FERC account indicators to tie the Company's O&M expense account statements with those of FERC (Exh. DPU 2-3, Att. 3).

In addition, the Department has examined the Company's revenues and expenses, including comparisons of expenses booked during the first three months of 2022 versus those booked during the first three months of 2023 (Exhs. NG-RRP-1a at 8-15; DPU 2-4 through DPU 2-12). The Company attributed most of the variances to cost changes, expense reclassifications, and prior period reconciliations (Exhs. DPU 2-4 through DPU 2-12).[12] To the extent any test-year revenues and expenses are found to be unrepresentative or unreasonable, the Department will consider the appropriate ratemaking treatment in the specific sections of this Order that follow.

The Department has also examined National Grid's accruals booked to reserve accounts and end-of-period reconciliations, as well as the Company's accounting policies (Exhs. DPU 2-1; DPU 2-2). The Company's accruals are booked in accordance with National Grid USA's Accounting Policy US AP 305.01.2, Accrued Liabilities (Exh. DPU 2-1, Att. 3).[13] All accounts are reconciled in accordance with National Grid USA's Account Reconciliations Policy US AP 800.05.1, which outlines the guidance, requirements, and processes for the preparation and review of balance sheet account reconciliations (Exh. DPU 2-7, Att. 7, at 3). According to the

12 In one instance, the Company identified an incorrect booking of two rights-of-way license agreement rental payments (Exh. DPU 2-5). The Company corrected this error in its revised cost of service schedules (Exh. NG-RRP-2, Sch. 24, at 3 (Rev. 4)).

13 Because National Grid USA's parent is a British corporation, US AP 305.01.2 generally adheres to the requirements of International Financial Reporting Standards, with several exceptions where generally accepted accounting principles are applied (Exh. DPU 2-3, Att. 3, at 5-6). Notwithstanding these financial reporting standards, the Department's accounting regulations, not those of domestic or foreign accounting organizations, govern the Company's operations in Massachusetts. G.L. c. 164, § 81; 220 CMR 51.01; The Berkshire Gas Company, D.P.U. 22-20, at 11 (2022); D.P.U. 20-120, at 19 n.21; Bay State Gas Company, D.P.U. 12-25, at 235 n.144 (2012).

Company, its account reconciliation process is intended to ensure that all balance sheet accounts are free of material errors and omissions, and that reconciliations are performed in accordance with National Grid USA's standards (Exh. DPU 2-7, Att. 7, at 3). Based on our review, we find that the Company has demonstrated that it properly recognized its accruals booked to reserve accounts, including its end of period reconciliations. D.P.U. 20-120, at 19. To the extent any adjustments associated with accrual accounts are warranted, the Department will consider the appropriate ratemaking treatment in the specific sections of this Order that follow.

Based on the above considerations, the Department finds that National Grid has satisfied the split test year threshold requirements and has demonstrated that its financial data is reviewable and reliable and represents a full accounting of the Company's operations for the test year. Therefore, we conclude that there is sufficient reviewable and reliable information in the record to evaluate the Company's filing based on a test year for the twelve months ended March 31, 2023.

IV. COMPREHENSIVE PERFORMANCE AND INVESTMENT PLAN

A. Introduction

In this proceeding, National Grid seeks to implement various ratemaking proposals as part of a five-year Comprehensive Performance and Investment Plan ("CPI plan") (Exh. NG-CPIP-1, at 6). The CPI plan includes an Infrastructure, Safety, Reliability, and Electrification ("ISRE") mechanism to recover certain core investments and investments and expenses necessary to execute the Company's Electric Sector Modernization Plan ("ESMP") investments; a proposed PBR-O plan, i.e., a PBR plan for O&M expenses only; a service quality ("SQ") proposal; and an Incurred Debt Recovery Factor ("IDRF") to request adjustments to revenues to reflect increases or decreases in interest rates during the five-year term (Exh. NG-CPIP-1, at 7-8, 122). The CPI plan also includes proposed Investment-Based Performance Incentive Mechanisms ("IPIMs") related to the proposed reconciling mechanism; Performance Incentive Mechanisms ("PIMS") related to the proposed PBR-O plan; and scorecard metrics (Exh. NG-CPIP-1, at 8). The Department discusses each of these components below.

B. Infrastructure, Safety, Reliability, and Electrification Mechanism

1. Company Proposal

a. Overview

National Grid proposes to create a new accelerated cost recovery mechanism, i.e., the ISRE mechanism, to recover its core capital investment and ESMP costs[14] incurred between January 1, 2024 and December 31, 2028 (Exh. NG-CPIP-1, at 7, 17, 36-38, 69). "Core" capital projects serve the Company's need to maintain and improve asset conditions and to continue to provide safe and reliable electric distribution service to its customers (Exh. NG-CPIP-1, at 19).[15]

[14] An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, § 53, codified at G.L. c. 164, § 92B, requires each of the electric distribution companies to submit an ESMP every five years to proactively upgrade the distribution and, where applicable, transmission system for the Department's review and approval.

[15] From 2009 to 2019, National Grid had a reconciling mechanism called the Capital Investment Recovery Mechanism ("CIRM") that allowed the Company to recover an annual revenue requirement between base distribution rate cases on core capital investments up to a $249 million investment cap and a one-percent revenue cap. D.P.U. 18-150, at 165-166, 176; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 82 (2009). In D.P.U. 18-150, the Department allowed a proposal to phase out the CIRM in 2018 and 2019 in favor of the PBR plan currently in place. D.P.U. 18-150, at 176-177. The Company's proposal to include capital additions placed in service since D.P.U. 18-150 is discussed in Section V.B.5. below.

In contrast, "ESMP costs" are required to proactively upgrade the distribution system and, where applicable, the associated transmission system pursuant to G.L. c. 164, § 92B(a) (Exh. NG-CPIP-1, at 110). National Grid proposes to recover: (1) the revenue requirement of the Company's core investments, including incremental operating costs, necessary to provide safe and reliable distribution service to its customers; (2) the total revenue requirement for investments in capital projects for the Company's ESMP, including incremental ESMP operating costs; and (3) IPIMs (Exh. NG-CPIP-1, at 7-9, 43-44).

National Grid seeks recovery of core investments and ESMP investments placed in service from January 1, 2024 through December 31, 2028, and incremental ESMP expenses (Exh. NG-CPIP-1, at 36-38, 69). The Company proposes to submit a filing annually on June 15th requesting approval to recover the costs of the core and ESMP investments placed in service and ESMP operating expenses incurred in the investment year (i.e., the prior calendar year) (Exh. NG-CPIP-1, at 38). If approved by the Department, the rate change associated with the ISRE mechanism filing would take effect on October 1st of each year (Exh. NG-CPIP-1, at 38). The Company proposes that the ISRE revenue requirement include: (1) the monthly revenue requirement for eligible ISRE investments recorded as in service in the ISRE investment year immediately prior to the recovery year; (2) the average annual revenue requirement for the year ending December 31st of the ISRE investment year two years prior to the recovery year, for cumulative eligible ISRE investments placed into service in the ISRE investment years two years prior to the recovery year; (3) the annual revenue requirement for the recovery year on eligible ISRE investments recorded as in service in the ISRE investment year immediately prior to the recovery year; and (4) allowed O&M expense (Exh. NG-PP-13, at 192; proposed M.D.P.U. No. 1532, at 2, § 2.9).

The Company states that it faces unprecedented capital investment needs over the next five years to provide safe and reliable service and to drive toward the Commonwealth's electrification and clean energy requirements and goals (Exh. NG-CPIP-1, at 35). National Grid explains that neither traditional cost-of-service ratemaking nor a historical trend-based PBR mechanism can sufficiently fund the level of core investments and ESMP investments expected over the next five years and beyond (Exh. NG-CPIP-1, at 35). The Company declares that the ISRE mechanism will enable it to undertake the substantial capital investments necessary to serve customers and achieve the Commonwealth's objectives effectively and efficiently by providing timely and annual recovery of its core investments and ESMP investments (Exh. NG-CPIP-1, at 35). The Company notes that in this instance it is not requesting either preapproval or preauthorization for any investments, whether for core investments or ESMP investments (Exhs. AG 6-25; DPU 29-9). While the Company's proposed tariff does use the term "preauthorized," the Company clarifies that preauthorized is meant to reflect that only the categories of investments applicable to the proposed investment cap are recoverable through the ISRE mechanism (Exh. DPU 29-9; proposed M.D.P.U. No. 1532, §§ 2.14, 2.15, 4).

b. <u>Investment Cap</u>

National Grid proposes an investment cap on the recovery of capital expenditures based on the Company's forecast of capital expenditures for each calendar year, subject to a cumulative spend bank (Exhs. NG-CPIP-1, at 43; NG-CPIP-Rebuttal-1, at 65). National Grid's forecasted core investments in 2023 dollars for each calendar year are $494 million for 2024, $586 million for 2025, $616 million for 2026, $624 million for 2027, and $630 million for 2028, for a five-year total of $2.950 billion (Exh. NG-CPIP-Rebuttal-2). National Grid's forecasted ESMP investments in 2023 dollars for each calendar year are zero for 2024, $78 million for 2025, $235 million for 2026, $317 million for 2027, and $370 million for 2028, for a five-year total of $1.001 billion (Exh. NG-CPIP-Rebuttal-2). The Company's forecasted core and ESMP investments combined in 2023 dollars are $494 million for 2024, $664 million for 2025, $852 million for 2026, $941 million for 2027, and $1.000 billion for 2028, for a five-year total of $3.950 billion (Exh. NG-CPIP-Rebuttal-2).

To calculate the cap on capital investment eligible for recovery for each year, the Company proposes to adjust the total core and ESMP investment forecast amount for each year by actual inflation as defined by the Handy-Whitman Index,[16] within the range of zero percent to eight percent (Exh. NG-CPIP-Rebuttal-1, at 65). An illustrative calculation of the inflation adjustment results in spend limits for core and ESMP expenditures combined of $519 million for 2024, $727 million for 2025, $968 million for 2026, $1.103 billion for 2027, and $1.207 billion for 2028 (Exh. NG-CPIP-Rebuttal-2).

Additionally, the cumulative spend bank would allow for year-to-year fluctuations in plant in service (Exh. NG-CPIP-1, at 43). National Grid proposes to set the cumulative spend bank at $158 million, which equals 20 percent of the average annual capital expenditure in 2023 dollars, i.e., 20 percent of $790 million (Exhs. NG-CPIP-1, at 43-44; NG-CPIP-Rebuttal-1,

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16 The Handy-Whitman Index is a data series that is based on the change in the actual cost of construction of infrastructure over time. Milford Water Company, D.P.U. 18-60, Report and Determination to the Supreme Judicial Court at 17 n.17 (2021).

at 65-66; NG-CPIP-Rebuttal-2). National Grid states that if plant in service for a calendar year is below the inflation-adjusted spend limit, then the spend bank will not be utilized (Exh. NG-CPIP-Rebuttal-1, at 69). If plant in service exceeds the inflation-adjusted spend limit, however, the excess cost up to the aggregate spend bank limit of $158 million is recoverable through the ISRE mechanism (Exh. NG-CPIP-Rebuttal-1, at 69). For example, if National Grid's plant in service in year one totaled $5 million less than the inflation-adjusted forecast for year one, the Company would be eligible to include the entire revenue requirement associated with the plant placed in service in year one and the $158 million spend bank would not change (Exhs. NG-CPIP-Rebuttal-1, at 68-69; NG-CPIP-Rebuttal-2). If National Grid's plant in service in year one totaled $5 million more than the inflation-adjusted forecast for year one, the Company would be eligible to include the entire revenue requirement associated with the plant placed in service in year one and the $158 million spend bank would decrease to $153 million for the remainder of the plan (Exhs. NG-CPIP-Rebuttal-1, at 68-69; NG-CPIP-Rebuttal-2).

c. Investment Categories – Core Investments

i. Customer Requests and Public Requirements

Customer requests and public requirements projects include: (1) customer requests, such as from new commercial and residential business, outdoor lighting, third-party attachments, and land rights requests; and (2) municipal and state requirements (Exh. NG-CPIP-1, at 65, 70). Establishing electric delivery service to new customers accounts for approximately 60 percent of the customer request and public requirements budget (Exh. NG-CPIP-1, at 71). The Company describes an increase in requested summer peak load per work order in fiscal year 2022 through fiscal year 2023 (Exh. NG-CPIP-1, at 55, 72-73).

ii. Damage/Failure

There are three major components of the Damage/Failure core investment category: (1) blanket projects, which covers substation and line failures; (2) reserve for specific projects, which is intended to address larger failures and is based on historic trends; and (3) major storms, which can vary significantly from year to year (Exh. NG-CPIP-1, at 77). Damage/failure projects are mandatory and non-discretionary (Exh. NG-CPIP-1, at 76-77). National Grid identifies increasing storm frequency and intensity as one of the primary factors contributing to damage/failure budget increases (Exh. NG-CPIP-1, at 77).

iii. Asset Condition

Investments in asset condition include projects that replace, repair, or upgrade assets that are at risk of failing and causing unplanned outages or unsafe conditions (Exh. NG-CPIP-1, at 80). The Company provides several examples of programmatic investments in this category, including: (1) inspection and maintenance program; (2) strategy to replace distribution substation batteries; (3) underground mainline cable strategy; (4) underground residential development and underground commercial development cable strategy; (5) oil fused cutouts; (6) porcelain disconnect program; and (7) blanket projects, which are intended to initiate, monitor, and report on projects under $100,000 in value (Exh. NG-CPIP-1, at 82-86).

iv. System Capacity and Performance

In the system capacity and performance category, National Grid includes projects that guarantee that the electric system has sufficient capacity to meet customer demand and to maintain power quality (Exh. NG-CPIP-1, at 92). Generally, projects in this category address loading conditions on substation transformers and distribution feeders to comply with the

Company's system and capacity loading policy and are designed to reduce degradation of equipment service lives due to thermal stress (Exh. NG-CPIP-1, at 92). In addition to accommodating load growth, system capacity and performance expenditures include the installation of new equipment, such as capacitor banks to maintain the requisite power quality required by customers and reclosers that limit the customer impact associated with a service event (Exh. NG-CPIP-1, at 93). This category also includes spending to improve the overall performance of the network, such as the reconfiguration of feeders and the installation of feeder ties (Exh. NG-CPIP-1, at 93).

The Company explains that due to the large increase in customer requests and public requirements, projects and upgrades in system capacity and performance have needed to be reprioritized; to meet demands resulting from incremental ESMP work and growing customer load demand, National Grid must now complete load relief projects (Exh. NG-CPIP-1, at 94). Rising costs can also be attributed to the Company's expansion of fault location, isolation, and service restoration ("FLISR") deployment and resiliency projects (Exh. NG-CPIP-1, at 94).

v. Non-Infrastructure

Non-infrastructure includes information technology ("IT"), fleet, small tools, property investments, and related projects (Exh. NG-CPIP-1, at 104-105). In this category, the Company addresses normal wear and tear, critical repair, and end-of-life systems in its facilities, with the goal to ensure that all facilities are safe and fit for purpose (Exh. NG-CPIP-1, at 104). A facilities condition assessment conducted between 2019 and 2020 identified sites in Malden, Worcester, North Andover, and Northborough as needing a high level of investment (Exhs. NG-CPIP-1, at 105; DPU 47-29 & Att.). In addition, the Company notes that it will be securing a new operating location to serve Quincy, Weymouth, Randolph, and Holbrook, since its outpost on Field Street in Quincy will be closed due to flooding mitigation work; relocating its operating location from Monson to Palmer; and redistributing employees from the facility it is closing in Waltham to other existing facilities (Exh. NG-CPIP-1, at 107).

vi. Climate Change and Resiliency

National Grid anticipates that more frequent extreme weather events driven by climate change will pose risks to the electric system, and the Company commits to taking proactive actions to address these potential risks (Exh. NG-CPIP-1, at 117). The Company has initiated its first system-wide climate vulnerability assessment to develop adaptation plans to minimize future climate risk (Exh. NG-CPIP-1, at 117). The Company states that understanding future climate hazards will allow it to make informed design decisions and update hardening programs to both protect its assets and improve reliability (Exh. NG-CPIP-1, at 118). National Grid used an internal climate change risk tool to map how the Company's infrastructure may be impacted by climate hazards and inform early preventative and adaptive measures to lower risk to power networks, equipment, and communities (Exh. NG-CPIP-1, at 120). The Company explains that its climate change risk tool uses data from the Fourth National Climate Assessment (Exh. NG-CPIP-1, at 120).[17] In addition, National Grid anticipates that climate hazards with the

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[17] The Fourth National Climate Assessment was completed in 2018 and is a comprehensive report on climate change and its impact on the natural environment, agriculture, energy production and use, land and water resources, transportation, and human health and welfare across the United States. Numerous federal agencies contributed to the Fourth National Climate Assessment, including the Federal Emergency Management Agency, the National Oceanic and Atmospheric Administration, and the Environmental Protection Agency (Exh. NG-CPIP-1, at 120). https://nca2018.globalchange.gov/

greatest risk of impact in Massachusetts include flooding, heatwaves and high temperatures, extreme wind, and ice accretion, but the Company is also beginning to review best practices for wildfire risk mitigation (Exh. NG-CPIP-1, at 118, 121).

National Grid explains that most of the necessary climate change-driven adaptations will be standard system updates and upgrades such as increased pole strength, consideration of ambient temperature, and expansion of coastal flood design (Exh. NG-CPIP-1, at 121). The Company also states that it is now necessary to plan for targeted adaptions (Exh. NG-CPIP-1, at 121). The Company proposes to include investments in temporary flood mitigation projects at five substation locations as part of its core investments, which are informed by the Company's climate vulnerability assessment (Exh. NG-CPIP-1, at 121). The Company used the climate change risk tool to screen its substations for high risk of flood, either now or in a future year (Exh. DPU 22-5). The substations will be selected and prioritized following site-specific evaluations and reviews of the Federal Emergency Management Agency's 500-year flood maps (Exhs. NG-CPIP-1, at 121; DPU 22-5). The Company has budgeted approximately $500,000 to further evaluate and assess the impacts of flooding on those five substations, based on its experience conducting flood mitigation efforts to date (Exh. DPU 22-5; Tr. 5, at 649-650).

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General does not argue against the fundamental structure of the ISRE mechanism but avers that the magnitude of the Company's forecasted investments is unreasonable (Attorney General Brief at 12, 14). The Attorney General maintains that her recommended modifications are necessary to control costs and create greater rate stability while allowing for investments that permit the Company to fulfill its obligation to provide safe and reliable service (Attorney General Reply Brief at 11, 13). The Attorney General's specific arguments in support of these positions are discussed in further detail below.

ii. Investment Cap

The Attorney General argues that the magnitude of National Grid's proposed investment cap is inappropriate and would fail to impose capital discipline on the Company (Attorney General Brief at 15). She argues that the Company's proposed spending under the ISRE mechanism will result in an average annual increase in capital investment of nearly 29 percent from 2023 to 2029, rising from roughly $299 to $1,259 invested per retail customer from 2023 to 2029 (Attorney General Brief at 14). To reduce the impact on retail rates of this investment increase, the Attorney General argues that the Department should set an investment cap of ten percent of total net plant in service based on the Company's reported financials for the prior year (Attorney General Brief at 15). She argues that this approach would provide rate stability and address affordability concerns for ratepayers while also permitting National Grid an annual allowed investment increase for the duration of the plan (Attorney General Brief at 15). The Attorney General also recommends that the Department allow the Company to seek "small and reasonable" exceptions to its investment cap for investments that demonstrably reduce greenhouse gas ("GHG") emissions in line with the Commonwealth's clean energy goals and/or provide documentable public benefits, such as outage reductions, outage duration reductions, or improved outage recovery times (Attorney General Brief at 41 & n.184).

iii. Capital Investment Plan

The Attorney General argues that her recommendations reduce the Company's proposed capital spending by about $1 billion over the next five years and that these reductions are necessary to protect ratepayers from burdensome rate increases (Attorney General Brief at 41-42). Further, she maintains that the capital bias inherent to regulated utilities incentivizes the Company to over-invest and that the Company is incapable of demonstrating the cost-effectiveness of its core investments (Attorney General Brief at 42).

The Attorney General also contends that the Company should time its core investments with sales volume increases to mitigate ratepayer impacts (Attorney General Brief at 42). She rejects the Company's assertions that it cannot increase sales without first increasing capacity, citing electric vehicle ("EV") charging as a counterpoint (Attorney General Brief at 43). She argues that most EV charging occurs at off-peak times, which increases utility sales volumes without driving a need for capacity increases (Attorney General Brief at 43).

In sum, the Attorney General objects to the scale of the Company's proposed investments, contending that even incorporating her $1 billion in reductions, the Company would still enjoy a spending increase of roughly 65 percent, or $1.1 billion (Attorney General Brief at 44). The Attorney General asserts that many of the Company's planned investments are discretionary, and some are an imprudent waste of ratepayer money (Attorney General Brief at 44). Further, she claims assessing prudency against alternatives is an inherently impossible task because the Company does not conduct cost-benefit analyses for many of these investments (Attorney General Brief at 44). The Attorney General also disagrees with any notion that the Company should serve customers via increasing reliability (Attorney General Brief at 45). She argues that the Company's reliability performance is generally favorable and that the main reason for customer dissatisfaction with the Company is due to prices (Attorney General Brief at 45). She contends that if the Company genuinely wished to increase its customer satisfaction, it would best do so by forgoing costly investments that raise rates significantly for marginal gains in reliability (Attorney General Brief at 45-46).

b. DOER

DOER argues that the Department should reject the Company's ISRE proposal for four primary reasons: (1) the ISRE mechanism is unwarranted; (2) it relies on deficient planning forecasts that do not sufficiently demonstrate the need to recover incremental costs; (3) it is not beneficial to ratepayers and does not protect against overinvestment; and (4) its reliance on volumetric pricing will discourage electrification (DOER Brief at 5).

DOER avers that the Company's ISRE mechanism proposal will result in an annual average of approximately $1.4 billion in spending over the next five years (DOER Brief at 6). DOER argues that National Grid's planned spending increase is not warranted and will lead to an exacerbated burden on ratepayers stemming from a nearly 1,600 percent increase in the revenue requirement associated with capital spending (DOER Brief at 7). DOER also maintains that the Department has previously rejected capital cost recovery mechanisms due to a company's depreciation expense accounting for a significant portion of its forecasted capital expenditures (DOER Brief at 7, citing D.P.U. 15-80/D.P.U. 15-81, at 48; Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 37 (2014); Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 79-80, 111 (2011)). DOER claims that the Company's depreciation expense in the final two rate years of the ISRE mechanism will be 66 percent and

38 percent, respectively, of the Company's illustrative revenue requirement (DOER Brief at 8). DOER argues that the Department should not approve the ISRE mechanism on the grounds that its investments are not properly designed, cost-effective, or appropriately tailored to achieve the Commonwealth's clean energy objectives (DOER Brief at 8).

DOER also asserts that the Company's demand forecasts are materially flawed, unreliable, and, therefore, insufficient to support the approval of the ISRE mechanism (DOER Brief at 8). Specifically, DOER argues that National Grid's forecasts of demand growth due to EV penetration are inaccurate because the Company fails to account for the shiftable and manageable nature of EV load or account for the concomitant deployment of solar photovoltaics and battery energy storage systems that will offset the peak demands on the system (DOER Brief at 10). DOER also contends that the Company's forecasts do not incorporate the impact of load management and the potential for demand reduction due to managed charging (DOER Brief at 10). Further, DOER maintains that the Company's energy storage forecast is inaccurate because it assumes no changes to the charge and discharge window of the Clean Peak Energy Portfolio Standard (DOER Brief at 10). The consequence of making such an assumption, as DOER argues, is that it creates unrealistic and drastic swings in the year-over-year peak impact as a result of the inaccurate assumption that energy storage will contribute to peak load instead of reducing it (DOER Brief at 11).

DOER also disagrees with approval of the ISRE mechanism on the grounds that it does not adequately constrain overinvestment incentives and, therefore, it is likely to be harmful to ratepayers (DOER Brief at 12-13). DOER contends that a prudency review alone is insufficient to adequately constrain the Company's incentive to overspend due to the reduction in regulatory lag (DOER Brief at 13, 15). Moreover, DOER alleges that both the structure of the ISRE mechanism as a reconciling mechanism and the investment cap that is central to the ISRE mechanism's operation do not provide any meaningful ratepayer protections (DOER Brief at 14). DOER also argues that any ratepayer protection afforded by the proposed five-year stay-out provision is undercut by the Company's ability to spend over its forecasts (DOER Brief at 15). While DOER acknowledges that National Grid has operated under two prior Department-approved capital recovery mechanisms, it points out that both prior mechanisms used an investment cap calculated as an average of three-year historical spending and DOER claims that the ISRE's divergence from a cap based on historical spending presents inadequate disincentives to overinvest, is inconsistent with Department precedent, and does not provide additional ratepayer benefits (DOER Brief at 16).

DOER also argues against the ISRE mechanism on the basis that it will increase volumetric electric rates and thereby reduce the incentive to electrify, which will hinder the attainment of the Commonwealth's climate goals (DOER Brief at 16). DOER maintains that affordable electric rates are an essential component of electrifying home heating and transportation, yet the ISRE Mechanism will exacerbate electric rates at a period when policy should be encouraging electrification (DOER Brief at 17-18). DOER contends that increased costs to ratepayers and the higher electric rates resulting from those costs run counter to the Commonwealth's and the ISRE mechanism's stated clean energy goals (DOER Brief at 18).

c. <u>EDF</u>

EDF takes issue with the Company's nearly four-fold spend increase in the customer and public requirements category because National Grid does not project a customer count increase commensurate with this growth in spending (EDF Brief at 8). EDF claims that the Company's increased spending derives from its use of 2024 projected spend as a starting point, which EDF characterizes as not representative of typical spending and unreasonably high (EDF Brief at 8). EDF cautions that if the Department permits a budget based on this level of initial spending, it would risk unnecessarily locking in higher rates for customers (EDF Brief at 8). EDF argues that the Department should implement the Attorney General's proposed cuts to the core investments budget to protect ratepayers from undue rate increases (EDF Brief at 8).

d. TEC and PowerOptions

TEC and PowerOptions argue that the Company's proposal to establish a volumetric rate adjustment to recover investments runs counter to the Commonwealth's climate goals (TEC and PowerOptions Brief at 4). TEC and PowerOptions contend that the magnitude of the ISRE mechanism's proposed spending could result in volumetric charges of roughly $0.02816 per kilowatt-hour ("kWh") by rate year five and such an increase would make electricity non-competitive with fossil fuels (TEC and PowerOptions Brief at 5). In addition, TEC and PowerOptions aver that a fully volumetric rate design will reduce the incentive for customers to electrify to such an extent that subsidies could be the only way to make electricity cost-competitive with fossil fuels (TEC and PowerOptions Brief at 5). They also contend that the economic rationale for a volumetric rate design is misplaced, arguing that many core investments recovered through the ISRE mechanism are not driven by usage (as a volumetric design would reflect) but rather by other factors like demand (TEC and PowerOptions Brief at 5). Further, they argue that a volumetric rate design produces significant differences between high and low load factor Rate G-2 and Rate G-3 customers (TEC and PowerOptions Brief at 5-6).

TEC and PowerOptions assert that the Department should not permit cost recovery through a fully volumetric rate adjustment if it approves the ISRE mechanism because a fully volumetric rate adjustment will disproportionately impact high load factor customers and reduce the incentive to electrify (TEC and PowerOptions Brief at 6). Instead, they support DOER's position that the ISRE factor should be recovered in a manner most similar to base distribution rates (TEC and PowerOptions Brief at 6).

e. Company

i. Introduction

National Grid submits that it is entering a period of rapid change and dramatic transition, created due to the Commonwealth's climate goals, that necessitates a fundamentally different approach to cost recovery (Company Brief at 19). National Grid argues that the ISRE mechanism will support the Company's investments during this time and provide a level of cost recovery commensurate with the scale of the Company's obligations (Company Brief at 27).

ii. Need for the ISRE Mechanism

National Grid argues that the ISRE mechanism is necessary to address the Company's core capital projects and ESMP expenditures (Company Brief at 27). The Company avers that its operating landscape has shifted dramatically since National Grid filed its prior base distribution rate case in 2018 while its obligation to provide safe and reliable service has not changed (Company Brief at 29). National Grid also maintains that the COVID-19 pandemic created new load centers in unexpected locations, shifted load timing and locations, and increased customers' reliance on reliable electrical service due to the increased prevalence of work-from-home jobs (Company Brief at 30).

At the same time, the Company contends that maintaining its System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI") performance scores over the coming years will be increasingly difficult as many of its already old assets continue to age and suffer increased stress due to electrification (Company Brief at 31-32). In updating and replacing these assets, the Company further argues that much of its investment spend in the coming years will be due to customer request and public requirements, which it maintains are mandatory and non-discretionary in their scope and timing (Company Brief at 34-35, 62).

iii. Investment Cap

In response to the Attorney General, the Company argues that while the ISRE mechanism demonstrates increasing costs relative to historical levels, those costs are reasonable and necessary to undertake the step change required to serve its customers and meet the Commonwealth's climate objectives (Company Reply Brief at 6). The Company further disagrees with the Attorney General's characterization of the ISRE mechanism, arguing that the proposed mechanism will be subject to multiple reviews by the Department and stakeholders and contains incentives for cost control, transparency, and accountability (Company Reply Brief at 6). National Grid contends that the Attorney General's proposed investment cap of ten percent of prior year net plant in service is arbitrary and unsupported by evidence (Company Reply Brief at 8-10).

The Company also objects to the Attorney General's proposed cap on the grounds that it would provide insufficient revenue support for the escalating investment costs over the coming years due to inflation (Company Reply Brief at 10). National Grid also argues that the Attorney General's proposed cap is unworkable with its ESMP goals because it would set an inappropriately low cap that could not keep pace with the Company's ESMP spending as it ramps up (Company Reply Brief at 10).

Further, National Grid claims that adopting the Attorney General's proposed spending cuts to core investments would be arbitrary and capricious (Company Reply Brief at 15). The Company argues that the cuts in question would reduce the customer request and public requirements budget by approximately $206 million, the asset condition budget by approximately $200 million, and the system capacity and performance budget by approximately $685 million (Company Reply Brief at 15-16, citing Exh. AG-WG-1, at 7; Tr. 5, at 762-763). The Company contends that such cuts would inhibit the Company's ability to execute mandatory, non-discretionary projects, eventually increase spending in the damage/failure category, and impede projects for which there is a justified and demonstrable need (Company Reply Brief at 15-16). If implemented, the Company argues that such cuts would leave it unable to commit to its five-year stay out as part of the PBR framework (Company Reply Brief at 16).

The Company rejects out of hand the Attorney General's suggestion that the Company implement a cost-benefit analysis before approving capital projects (Company Reply Brief at 16). National Grid argues that such a requirement would be unprecedented, impractical, and out of step with every other utility commission across the country (Company Reply Brief at 16, citing Tr. 11, at 1,417-1,420).

Finally, the Company disagrees with the Attorney General's proposal that the Company accept a "just-in-time" spending approach of timing capital spending with sales volume increases (Company Reply Brief at 17). National Grid argues that such an approach is unworkable and would prevent it from successfully executing its public service obligation (Company Reply Brief at 17). The Company maintains that its planning, permitting, and construction timelines take many months or years, and timing these investments to load growth is infeasible (Company Reply Brief at 17). Further, the Company contends that sales volumes can increase only if capacity exists to serve those increases, so the Company by definition must undertake investments prior to load growth (Company Reply Brief at 17).

3. Analysis and Findings

a. Introduction

In D.P.U. 07-50-A at 48, the Department recognized that full revenue decoupling for electric companies would, all other things being equal, remove the opportunity for companies to retain additional revenues from sales growth between base distribution rate proceedings -- revenues that companies could have used to pay for increased O&M costs, costs related to system reliability, and capital expansion projects. D.P.U. 11-01/D.P.U. 11-02, at 73-74, 107; Western Massachusetts Electric Company, D.P.U. 10-70, at 47 (2011). The Department also recognized that changes in a distribution company's costs could arise from inflationary pressures on the prices of the goods and services it uses. D.P.U. 07-50-A at 49; see also D.P.U. 10-70, at 53. Accordingly, the Department stated that, along with revenue decoupling, it would consider company-specific proposals that adjust target revenues to account for capital spending and inflation but that a company would bear the burden of demonstrating the reasonableness of its proposal. D.P.U. 07-50-A at 50; see also D.P.U. 11-01/D.P.U. 11-02, at 107-108; D.P.U. 10-70, at 47. Additionally, the Department has recognized that electric distribution companies ("EDCs") will need flexibility to address the evolving energy and climate policies governing them, as well as to maintain aging infrastructure and enhance resiliency to address the impacts of climate change. NSTAR Electric Company, D.P.U. 22-22, at 60 (2022); D.P.U. 18-150, at 53; see also Electric Sector Modernization Plans, D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 63 (August 29, 2024) (recognizing importance of flexibility for EDC planning processes, especially in response to evolving conditions); NSTAR Gas Company, D.P.U. 19-120, at 72 (2020) (finding that rate relief during a PBR term to support increasing capital needs driven by a changing operating environment was appropriate). In Section IV.C.4. below, we allowed a modified PBR-O to address annual adjustments to target revenue to account for O&M-related inflation less O&M productivity plus a consumer dividend. Here, we address the Company's proposed ISRE mechanism.

In prior cases, when deciding whether to accept a new capital cost recovery mechanism, the Department closely examined whether the mechanism was warranted and whether it was in the best interest of ratepayers. D.P.U. 15-80/D.P.U. 15-81, at 44-56; D.P.U. 15-155, at 55-56; D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 51-52; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-39, at 80-84 (2009).[18] The

[18] National Grid was the first electric distribution company to receive approval of a capital cost recovery mechanism following revenue decoupling. D.P.U. 09-39, at 80-84. Subsequently, the Department approved a capital cost recovery mechanism for Fitchburg Gas and Electric Light Company. D.P.U. 15-80/D.P.U. 15-81, at 50. The Department also previously rejected a capital cost recovery mechanism for Western Massachusetts Electric Company. D.P.U. 10-70, at 52.

Department has allowed capital cost recovery mechanisms in cases where a company has adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate proceedings. Boston Gas Company, Essex Gas Company, Colonial Gas Company, D.P.U. 10-55, at 121-122, 132-133 (2010); D.P.U. 09-39, at 79-80, 82; Bay State Gas Company, D.P.U. 09-30, at 133-134 (2009). Conversely, without compelling evidence of lost growth in sales, the Department has declined to approve a capital cost recovery mechanism as an element of decoupling. D.P.U. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 109-111; D.P.U. 10-70, at 47; see also D.P.U. 07-50-A at 50. The Department has found that, where a company failed to demonstrate that there were extraordinary circumstances that prevented it from acquiring the capital necessary to make required investments in its infrastructure, approval of a capital cost recovery mechanism was neither warranted nor in the best interests of ratepayers. D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50, 52.

Here, National Grid requests approval of its ISRE mechanism to support its core capital and ESMP expenditures and certain incremental ESMP expenses between base distribution rate cases (Exh. NG-CPIP-1, at 36-37). The merits of National Grid's proposal must be evaluated in the context of its current circumstances and in light of the current regulatory framework.

b. ESMP Expenditures

First, we address National Grid's proposal to recover ESMP costs through the ISRE mechanism. While this case was pending, the Department adjudicated the EDCs' first ESMPs, which were filed pursuant to G.L. c. 164, § 92B on January 29, 2024, and decided on August 29, 2024. In the Department's Order, we approved National Grid's ESMP with modifications and

addressed the appropriate cost recovery framework for ESMP costs.
D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 435-447, 479. We found that it was appropriate to allow short-term targeted cost recovery for ESMP costs and determined that we would investigate the parameters of an ESMP cost recovery mechanism in the second phase of the ESMP proceedings. D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 444. Further, we determined that the development of short- and long-term cost recovery frameworks for ESMP costs will involve a balancing of the need to provide sufficient certainty to the EDCs and their investors regarding recovery of the revenues necessary to support the ramp up in clean energy investments associated with achieving the Commonwealth's GHG emissions targets, versus the Department's equally important obligations to ratepayers to preserve affordability through rigorous oversight of utility expenditures to ensure that costs are minimized and the EDCs are giving due consideration to alternative, lower cost solutions. D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 447. The Department's investigation in the second phase of the ESMP proceedings may include, but need not be limited to: (1) definitions of costs eligible for recovery; (2) cost containment provisions such as budget or revenue caps; (3) documentation required to support cost recovery; (4) the EDCs' processes for evaluating alternatives and addressing changed circumstances during the five-year ESMP terms; (5) consideration of possible mechanisms to encourage innovative approaches designed to minimize costs for ratepayers; and (6) planned obsolescence of the ESMP mechanism. D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 444.

The Department stated that we would rule on National Grid's proposal to recover ESMP costs through the ISRE mechanism and, subsequently, initiate the ESMP cost recovery mechanism phase of the ESMP proceeding for NSTAR Electric Company ("NSTAR Electric"), Fitchburg Gas and Electric Light Company ("Unitil"), and, if necessary, National Grid, soon after our decision in the instant proceeding. D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 445. We determine that it is appropriate to establish a separate ESMP cost recovery mechanism for National Grid in the second phase of the ESMP proceedings, consistent with NSTAR Electric and Unitil. This approach will ensure consistent ratemaking treatment for ESMP costs for all of the EDCs while supporting the step change needed to achieve the Commonwealth's GHG emissions targets in the current operating environment.

D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 447; see also Boston Gas Company and Colonial Gas Company, D.P.U. 17-170, at 60 (2018) (directing utility to maintain separate contribution in aid of construction ("CIAC") account to ensure uniform accounting treatment among all local gas distribution companies ("LDCs")); Effect of Reduction in Federal Income Tax Rates on Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15-A at 58 (2018) (directing utility to implement a revenue requirement adjustment for tax savings consistent with ratemaking treatment approved for other utilities); Cambridge Electric Light Company, D.P.U./D.T.E. 97-111, at 83 (1998) (finding that a generic proceeding was the appropriate forum to develop comprehensive service quality of service standards because it would lead to a fair and consistent treatment of all EDCs); Tofias v. Energy Facilities Siting Board, 435 Mass. 340, 349 (2001) ("[a] party before a regulatory agency . . . has a right to expect and obtain reasoned consistency in the agency's decisions"). Therefore, the Department determines that National Grid shall recover ESMP costs pursuant to the framework that will be investigated in the second phase of the Company's ESMP proceeding, and the Department disallows ESMP cost recovery through the proposed ISRE mechanism.

The Department also determined that the Company shall continue to recover its provisional system planning program costs[19] through is existing mechanism. D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 445. The Department finds here, for transparency and consistency with the other EDCs, that National Grid's future proposals relating to EV programs shall be submitted as separate filings and subject to the precedent and tariffs for each existing EV program mechanism. See D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 446-447 (requiring EDCs to submit EV program proposals as discrete filings). Moreover, we determined that for NSTAR Electric and Unitil, including ESMP costs in a new ESMP mechanism rather than extending the grid modernization factors, which are subject to specific standards of review that may not apply to ESMP costs, will allow for a more efficient and orderly review process and avoid confusion among stakeholders. D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 444-445. The Department makes the same determination here for National Grid's ESMP costs and grid modernization factors.

c. Need to Recover Incremental Core Investments Between Base Distribution Rate Proceedings

Next, to determine whether the ISRE mechanism is a reasonable cost recovery method for the Company's core investments, the Department first considers whether the Company has been unable to fund capital investments needed to meet its public service obligations with long-term debt and equity resources at a reasonable cost and, if it has, whether and to what extent

[19] In Provisional System Planning Program, D.P.U. 20-75-B at 2, 41 (2021), the Department established provisional cost allocation requirements for planning and funding upgrades to the electric power system to foster timely and cost-effective development and interconnection of distributed generation until a long-term system planning program was established.

there is a link between its operation under revenue decoupling and these claimed outcomes (Exh. NG-CPIP-1, at 36). D.P.U. 11-01/D.P.U. 11-02, at 107-108; D.P.U. 10-70, at 51-52; D.P.U. 07-50-A at 50. If the answer to these questions is in the affirmative, the Department will consider whether the ISRE mechanism is reasonably designed to achieve its intended goal and how its implementation will affect ratepayers and the Company's financial well-being. D.P.U. 10-55, at 66, citing D.P.U. 07-50-A at 50.

To meet its service requirements, the Company must invest in distribution infrastructure. See Boston Edison Company, Cambridge Electric Light Company, and Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 57 (2009) (a monopoly service provider has a public service obligation to provide reliable service at the lowest cost to customers); Boston Edison Company, D.P.U. 85-266-A/D.P.U. 85-271-A at 6-7 (1986); Boston Edison Company, D.P.U. 86-71, at 15-16 (1986). To assess the Company's inability to fund its capital expenditures, the Department compares National Grid's core capital budget against its depreciation expense recovered in rates. D.P.U. 15-80/D.P.U. 15-81, at 48; D.P.U. 13-90, at 37; D.P.U. 11-01/D.P.U. 11-02, at 109-110. Beginning October 1, 2024, the Company will recover $181,468,373 annually through its depreciation expense in base distribution rates (see Section VI.B. below), as compared to its fiscal year 2023 capital expenditures of approximately $389 million (Exh. NG-CPIP-Rebuttal-3, at 1). The Company projects that it will experience a significant increase in core capital expenditures throughout the plan, reaching approximately $443 million in fiscal year 2024 and $955 million in fiscal year 2029 (Exhs. NG-CPIP-1, at 55, 58; NG-CPIP-Rebuttal-1, at 63-69; NG-CPIP-Rebuttal-2; NG-CPIP-Rebuttal-3, at 1) (fiscal year numbers adjusted for inflation). Taking into account the uncertainties inherent in National

Grid's forested capital expenditures, as discussed below, we find that National Grid has provided sufficient evidence to demonstrate that it will be unable to fully fund its projected increases in capital expenditures through its base distribution rate depreciation expense (Exhs. NG-CPIP-1, at 55, 58; NG-CPIP-Rebuttal-1, at 63-69; NG-CPIP-Rebuttal-2; NG-CPIP-Rebuttal-3, at 1).

Additionally, revenue decoupling prevents the Company from collecting additional revenue from sales growth, which eliminates a source of revenues that may be used to fund capital investments in its distribution system that are intended to ensure safe and reliable service. In the recent past, increasing energy efficiency and customer conservation impacted the Company through declining sales (Exh. NG-MECO-1, at 11). D.P.U. 18-150, at 51. For MECo and Nantucket Electric combined, sales volume declined about 5.7 percent (21,271 gigawatt hours ("GWh") to 20,065 GWh) from 2014 through 2017 and about 3.6 percent (19,859 GWh to 19,135 GWh) from 2018 through 2022 (Exh. AG 4-10, Att.). Therefore, the evidence in this proceeding shows that the Company was previously unable to sustain positive sales growth and, in planning for electrification to achieve the Commonwealth's net zero emissions target for 2050, the Company expects that customer usage will increase at an average annual rate of 1.3 percent through 2029 (Exhs. NG-MECO-1, at 11; AG 4-10, Att.). In turn, growth in revenues in the coming years will be unable to support the level of capital investment necessary to maintain safe and reliable service as well as meet the Commonwealth's clean energy policy goals.

Based on these considerations, the Department finds that National Grid has adequately demonstrated its need to recover incremental core capital investment costs between base distribution rate cases, so that the Company is able to meet its public service obligations and obtain long-term debt and equity financing at a reasonable cost. Accordingly, we will allow the operation of a capital cost recovery mechanism for core investments, subject to our findings below. D.P.U. 15-80/D.P.U. 15-81, at 47; D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80, 82; D.P.U. 09-30, at 133-134.

d. Investment Cap

As discussed above, the Company proposed an investment cap calculated as: (1) National Grid's annual calendar year forecasted core and ESMP expenditures for 2024-2028, adjusted each year of the plan by the actual Handy-Whitman Index within the range of zero to eight percent; and (2) a $158 million aggregate spend bank (Exhs. NG-CPIP-1, at 43; NG-CPIP-Rebuttal-1, at 63-66). Recalculating the Company's proposed spend bank using its method but applying it only to the forecasted core capital expenditures results in a $118 million spend bank (see Exh. NG-CPIP-Rebuttal-2).[20] The Attorney General opposes National Grid's investment cap and spend bank proposal and instead advocates for an investment cap of ten percent of the Company's net plant in service for the prior fiscal year (Attorney General Brief at 14-15).

Capital cost recovery mechanisms reduce and potentially eliminate the important incentive that regulatory lag provides to companies to maintain an appropriate balance between investing in capital improvements and incurring O&M expenses. D.P.U. 15-155, at 55-56; D.P.U. 09-39, at 81. To reach a balance between: (1) providing the Company with sufficient capital funding to ensure the safety and reliability of the electric service that it provides to its ratepayers; and (2) protecting its ratepayers against the incentive the Company has to overinvest

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20 $2.950 billion / 5 = $590 million * 20 percent = $118 million.

in capital infrastructure to produce earnings for its shareholders, the Department has directed companies to implement investment caps. D.P.U. 18-150, at 176; D.P.U. 15-155, at 56; D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 09-39, at 81-82.

After review of the record and the arguments of the parties, we find it appropriate to disallow National Grid's proposed investment cap. As an initial matter, we note that no capital cost recovery mechanism previously approved by the Department has enabled contemporaneous cost recovery for all incremental core investments between base distribution rate cases, let alone contemporaneous cost recovery for all incremental core investments with allowances for inflation and a cumulative spend bank, as National Grid has proposed (Exhs. NG-CPIP-1, at 43; NG-CPIP-Rebuttal-1, at 63-66). See, e.g., Fitchburg Gas and Electric Light Company, D.P.U. 23-80/D.P.U. 23-81, at 43-49 (June 28, 2024) (approving a "K-bar" adjustment to provide funding for capital investments during a PBR term to recover a portion of incremental capital expenditures); D.P.U. 22-22, at 59-67 (approving a similar "K-bar" adjustment); D.P.U. 20-120, at 74-79 (approving limited rate adjustments for post-test-year capital investments during a PBR term); D.P.U. 19-120-A at 8-10 (approving limited rate adjustments for post-test-year capital investments during a PBR term); D.P.U. 15-155, at 55-57 (approving a capital cost recovery mechanism with an investment cap based on the three-year average of historic capital spending and a one percent rate cap on the change in annual revenue requirement); D.P.U. 15-80/D.P.U. 15-81, at 43-49 (approving a capital cost recovery mechanism with a similar investment cap and rate cap). As proposed by National Grid, all categories of investments that it would make between base distribution rate cases would be recoverable through an annual mechanism (Exh. DPU 21-1). Additionally, the Department has previously rejected cost recovery proposals based on the subjectivity, speculation, and uncertainty inherent in projections of future costs. See, e.g., D.P.U. 17-170, at 178; D.P.U. 15-155, at 324-326; D.P.U. 14-150, at 280-281; Bay State Gas Company, D.P.U. 12-25, at 331 (2012); D.P.U. 07-50-A at 52, citing Eastern Edison Company, D.P.U. 1580, at 19 (1984). These same concerns apply to the Company's forecasted ISRE mechanism investment cap and spend bank. The record shows that the Company's proposed investment cap based on forecasted core capital expenditures is subject to significant uncertainty due to recent increases in costs of materials, labor, and technology (Exhs. NG-CPIP-1, at 62-63, 72; AG 6-2). Further, National Grid's five-year capital plan is based on preliminary or conceptual cost estimates that are susceptible to change, unlike its annual planning process, which sets capital budgets based on engineering level cost estimates (Exh. NG-CPIP-1, at 66, 68). See also D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 145, citing D.P.U. 24-11, Exh. DPU 1-1 (cost estimates provided in ESMPs are only preliminary or conceptual and must be refined based on final scope, engineering, design, and vendor quotes prior to seeking approval through the utilities' internal project authorization processes); D.P.U. 19-120, at 68-69 (discussing differences between five-year strategic planning processes and annual capital budgeting processes). Given the unprecedented scope of incremental core investment proposed for accelerated recovery through the ISRE mechanism and the speculative and uncertain nature of the Company's proposed investment cap and spend bank, the Department concludes that, as proposed, National Grid's ISRE mechanism does not strike an appropriate balance between: (1) providing the Company with sufficient funds to invest to ensure the safety and reliability of the electric service it provides to its ratepayers; and (2) protecting its ratepayers against the incentive the Company has to overinvest in capital infrastructure to produce earnings for its shareholders. To reach a balance between these opposing incentives, the Department directs National Grid to make modifications to its proposed ISRE mechanism as articulated below.

Turning to the Attorney General's cap proposal, we decline to accept the Attorney General's recommendation to institute a cap of ten percent of the Company's prior year net plant in service. The Attorney General did not submit evidence articulating why she chose a ten-percent figure or what analysis undergirds such a figure. Further, the Attorney General has not provided record evidence demonstrating how such a cap based on net plant in service would work in practice, why an investment cap based on net plant in service is practicable, or how it would be incorporated as part of the Company's ISRE mechanism. The Attorney General's primary rationale for such a cap is that the Company financials from the prior year are "easy to monitor, known and verifiable, and will provide stability and certainty for ratepayers" (Exh. AG-DED-1, at 13). While these are all positive attributes, we do not find them to be sufficiently persuasive to approve the Attorney General's proposed investment cap. The Attorney General acknowledged that the ten-percent cap was subjective and policy driven (Exhs. DPU-AG 3-2; DPU-AG 3-5). Further, the Attorney General did not provide any quantitative or qualitative support for her proposal (Exhs. DPU-AG 3-2; DPU-AG 3-5). Accordingly, we find the Attorney General's analysis supporting her proposal unpersuasive and, therefore, we decline to accept the Attorney General's proposed cap.

To determine an appropriate cap, the Department must balance its goal of enabling the provision of safe and reliable service with the goal of rate continuity. Bay State Gas Company, D.T.E. 05-27, at 305 (2005); Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 252 (2002); Boston Gas Company, D.P.U. 88-67 (Phase I), at 201 (1988). The intent of capping the Company's investments or revenues is to provide a reasonable opportunity for the recovery of associated costs by National Grid, balanced against the potential bill impacts on ratepayers, rate continuity, and the risk of rate shock. After considering the magnitude of the Company's planned core investments over the CPI plan term, we find that a cap on annual revenue requirement increases (i.e., change in the annual ISRE mechanism cost recovery) equal to three percent of total revenue[21] strikes an appropriate balance between providing adequate revenue support for the Company and its shareholders and rate continuity (Exhs. NG-CPIP-1, at 74-75; NG-CPIP-Rebuttal-1, at 63-69; NG-CPIP-Rebuttal-2; NG-CPIP-Rebuttal-3; AG 1-2, Atts. 41-44). Further, our decision will provide stability and predictability in ISRE mechanism cap calculations that benefit both the Company in its planning for core capital work and allow ratepayers the opportunity to adjust in response to the associated bill impacts (Exhs. NG-CPIP-1, at 74-75; NG-CPIP-Rebuttal-1, at 63-69; NG-CPIP-Rebuttal-2; NG-CPIP-Rebuttal-3; AG 1-2, Atts. 41-44).

While the Department allows accelerated cost recovery for core investments under these circumstances, it is imperative that the investment cap achieve meaningful ratepayer protection against the Company's incentive to overspend. Therefore, any portion of the annual ISRE

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[21] Caps based on the change in total revenues are commonly used as a ratepayer protection. See, e.g., G.L. c. 164, § 145(f) (authorizing Department to establish revenue cap for gas system enhancement plans) Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-02, at 3 (2023) (one-percent revenue cap) Aquarion Water Company of Massachusetts, D.P.U. 17-90-A at 30 (2019) (three-percent revenue cap); D.P.U. 15-155, at 55-57 (one-percent revenue cap); D.P.U. 15-80/D.P.U. 15-81, at 43-49 (one-percent revenue cap); Boston Gas Company and Colonial Gas Company, D.P.U. 15-46, at 4 (2016) (one-percent revenue cap).

mechanism adjustment (i.e., revenue requirement) that exceeds the three percent cap shall not be eligible for deferral for future recovery. The Company may seek to include any prudent, in-service investments in its next base distribution rate case and may seek to include the revenue requirement on those investments in base distribution rates at that time using traditional cost of service ratemaking principles.

Additionally, the Department finds that it is appropriate to continually evaluate and monitor changes in the market that could violate our existing ratemaking goals and render this cap inappropriate. D.P.U. 09-39, at 88. Accordingly, the Department may review and modify such a cap, as necessary, over the course of National Grid's ISRE mechanism filings if the ISRE mechanism, and/or a combination of all the Company's reconciling mechanism bill impacts, become excessive. In its compliance filing to this Order, the Department directs the Company to revise its proposed ISRE mechanism tariff accordingly.

The Department makes no determination regarding the optimal level of investment the Company should make in its distribution infrastructure to provide safe and reliable electric service to its ratepayers in satisfaction of its public service obligation.[22] National Grid's maintenance and replacement activities may lead the Company to identify capital investments that exceed the level allowed for annual cost recovery. The revenue cap is distinguishable from the Company's obligations to ensure safe and reliable service. Although the revenue cap limits the rate impact on customers, it does not impose on National Grid any limit on the level of capital investment that it can or should undertake in a given year. New England Gas Company,

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22 In this regard, the Department relies on the Company to make sound management, business, and engineering decisions.

D.P.U. 10-114, at 66 (2011). National Grid has full discretion to exercise its judgment in fulfilling its obligation to maintain the safety and reliability of its distribution system. D.P.U. 10-114, at 66.

e. Filings and Rate Adjustments

The Company proposes to submit a filing on June 15th of each year for the Department's approval of cost recovery of its core investments in the investment year (i.e., the prior calendar year), which will take effect on October 1st (Exh. NG-CPIP-1, at 38). For core investments, the Company proposes that the ISRE revenue requirement be calculated to recover: (1) the monthly revenue requirement for eligible ISRE investments recorded as in service in the ISRE investment year immediately prior to the recovery year; (2) the average annual revenue requirement for the calendar year ending December 31st of the ISRE investment year two years prior to the recovery year, for cumulative eligible ISRE Investments placed into service in the ISRE investment years two years prior to the recovery year; and (3) the annual revenue requirement for the recovery year on eligible ISRE Investments recorded as in service in the ISRE investment year immediately prior to the recovery year (Exh. NG-PP-13, at 192; proposed M.D.P.U. No. 1532, at 2, § 2.9).[23] The proposed ISRE mechanism allows for additional revenue support in between rates cases as compared to the Company's prior Capital Investment Recovery Mechanism ("CIRM"). For example, the Company's ISRE mechanism proposal introduces regulatory lag for core investments of ten to 22 months compared to 24 months under the CIRM

[23] The Company's proposed definitions: "ISRE Investment Year" is the annual period beginning on January 1st and ending on December 31st. "Recovery Year" is the calendar year in which the ISRE mechanism factor becomes effective (Exh. NG-PP-13, at 192; proposed M.D.P.U. No. 1532, at 2, 4, §§ 2.8, 2.23).

(Exhs. NG-CPIP-1, at 38; NG-CPIP-4a; DPU 29-11). It also allows the Company to begin collection of the revenue requirement more quickly compared to the CIRM (Exh. DPU 29-11). Using an investment year of 2022, for example, through an ISRE mechanism factor beginning October 1, 2023, the Company may recover the monthly revenue requirement incurred in 2022 for that investment as well as the annual revenue requirement incurred in 2023 for that investment. Applying the provisions under the CIRM, the Company would not have been eligible to recover any of the 2022 revenue requirement at any time for that same investment and would not have begun collection of the 2023 revenue requirement until March 1, 2024.

Capital trackers like the ISRE mechanism are intended to provide rate relief in between base distribution rate cases to fund capital investments that would otherwise be funded through sales growth. Similar to our analysis above on the ISRE mechanism cap, the Department must balance its goal of enabling the provision of safe and reliable service with the goal of rate continuity while providing for a reasonable opportunity for the recovery of costs, balanced against the potential bill impacts on ratepayers, rate continuity, and the risk of rate shock. D.T.E. 05-27, at 305; D.T.E. 02-24/25, at 252; D.P.U. 88-67 (Phase I), at 201. Therefore, the Department finds that only the revenue requirement incurred in the calendar year prior to the recovery year is eligible to be included in the ISRE mechanism factor for effect in the recovery year. Using the example described above of an example investment year of 2022, the ISRE mechanism factor for rates effective October 1, 2023, the Company may recover the monthly revenue requirement incurred in 2022 for that investment. The annual revenue requirement incurred in 2023 for that investment is not eligible for recovery through the ISRE mechanism factor until October 1, 2024.[24] In other words, the recovery of revenue requirement through the ISRE mechanism factor must lag one year from incurrence of that revenue requirement, so that the 2023 revenue requirement shall not be recovered through any ISRE mechanism factor that is in effect during calendar year 2023. The Department finds that this strikes an appropriate balance between providing resources for the Company and rate continuity to ratepayers and is consistent with ratemaking treatment for similarly approved capital cost recovery mechanisms that recover core investments. See, e.g., D.P.U. 09-39, at 83-84; D.P.U. 15-80/D.P.U. 15-81, at 53; D.P.U. 18-150, at 175. In making this directive, the Department notes that we are not denying the collection of this revenue requirement but directing the Company to delay it for collection through the next year's ISRE mechanism factor, consistent with the design of prior core capital investment recovery mechanisms. Further, the Company may not collect interest on this balance. Accordingly, we direct the Company to revise its definition of ISRE Revenue Requirement, as well as any other revisions necessary to meet these directives, in its compliance ISRE mechanism tariff (Exh. NG-PP-13, at 192; proposed M.D.P.U. No. 1532, at 2, § 2.9).

The Department has found that the funds from depreciation expense are intended to allow a company to recover its capital investments in a timely and equitable fashion over the service lives of the investments. Boston Gas Company and Colonial Gas Company, D.P.U. 14-132, at 63 (2015); Hingham Water Company, D.P.U. 1590, at 22-23 (1984). National Grid's depreciation, however, reduces the Company's rate base and the required return on rate base that

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[24] The Department allows the recovery of the investment year monthly revenue requirement in the recovery year (a departure from the Company's previously approved CIRM calculation for core capital investment recovery).

the Company recovers each year following the year associated with the test year-end investment in plant in service. A depreciation offset is warranted when a company has a capital recovery mechanism that recovers the revenue requirement for all capital investment in service after the test year of its last rate case because under such a capital recovery mechanism, there are no unrecovered capital costs to offset the lower required return caused by the depreciation of rate base. As such, some prior capital recovery mechanisms that recover the revenue requirement for all capital expenditures in service after the test year include a depreciation offset. Aquarion Water Company of Massachusetts, D.P.U. 17-90, at 72-73 (2018); D.P.U. 09-39, at 79; D.P.U. 15-80/D.P.U. 15-81, at 55. However, in approving certain capital cost recovery mechanisms such as the targeted infrastructure reinvestment factor, which limit the expenditures eligible for recovery, the Department has not required companies to net out their depreciation expense in calculating their revenue requirements. D.P.U. 12-25, at 58-59. Similarly, the Department did not require an adjustment or offset for the depreciation expense in base rates in calculating the revenue requirement for the Gas System Enhancement Plans. D.P.U. 14-132, at 54, 64-65. Despite the broad scope of this modified ISRE mechanism, encompassing all the Company's core investments, the Department does not find it appropriate to direct a depreciation net out in this instance.

f. Intervenor Proposed Modifications

Next, the Department addresses the Attorney General's and EDF's recommendation to reduce by $1 billion the Company's spending on ISRE investments; and the Attorney General's recommendations that the Company accept a "just-in-time" approach to its spending, and that the Company implement cost-benefit analyses to justify its core investments. As stated in the prior section, the Department makes no determination regarding the optimal level of investment the Company should make in its distribution infrastructure. In this regard, the Department relies on the Company to make sound management, business, and engineering decisions. Massachusetts Electric Company v. Department of Public Utilities, 469 Mass. 553, 559 (2014) (holding that in applying the prudence standard it is not appropriate for the Department to merely 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 (1983); see also D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 80 ("Generally, notwithstanding our regulatory oversight responsibilities over the Companies, the Department may not interfere with reasonable company judgments made in good faith and within the limits of reasonable discretion."). Therefore, we decline to accept the Attorney General's and EDF's recommendations.

The Department also acknowledges the concerns of DOER, TEC, and PowerOptions regarding the fact that an increase to volumetric electric rates would, all else being equal, disincentivize electrification and thereby impede the Commonwealth's climate goals. While the Department declines to accept the Company's proposal to implement a new "Electrification Pricing" option within the residential customer class, we are directing the Company to develop a heat pump rate as detailed in Section XV.C.4. below. The Department is also making several changes to its rate design as it pertains to commercial and industrial ("C&I") customers that will mitigate the impact of volumetric charges on rates, as discussed below in this Order. The Department's intent in approving a modified ISRE mechanism factor is that upon filing its next base distribution rate case, the Company will include these investments in rate base, and at that time, will then be eligible to collect the associated revenue requirement pursuant to the approved base distribution rate design structure.

4. Conclusion

The Department approves a modified ISRE mechanism for core capital expenditure cost recovery. Cost recovery treatment of ESMP investments and incremental ESMP operating costs will be determined in the second phase of the ESMP proceedings. In Section IV.F.4. below, the Department rejected National Grid's proposed IPIMs, and accordingly, the Company shall not collect or credit IPIM incentives or penalties through the approved ISRE mechanism. In compliance with this Order, the Department directs the Company to modify its ISRE mechanism tariff according to the foregoing directives.

C. Performance-Based Ratemaking Proposal

1. Introduction

In D.P.U. 18-150, at 55-56, the Department approved a PBR mechanism with a five-year term for the Company. The PBR mechanism allowed National Grid 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, i.e., exogenous events, either positive or negative. D.P.U. 18-150, at 74-75. The PBR mechanism included a productivity offset, or "X factor," of -1.72 percent. D.P.U. 18-150, at 60. Further, the PBR mechanism included a 40-basis point consumer dividend as a deduction to the PBR adjustment when inflation exceeded two percent, a 20-basis point deduction when inflation was between one and two percent, and no deduction when inflation was below one percent. D.P.U. 18-150, at 64-65. The PBR mechanism also included an earnings sharing mechanism ("ESM") that incorporated a 200-basis point sharing threshold above the Company's authorized return on equity ("ROE"). D.P.U. 18-150, at 71.

As discussed in further detail below, in the instant proceeding, the Company proposes to renew its PBR mechanism with certain modifications. National Grid proposes to continue operating under a PBR framework but applied only to its O&M expenses (Exh. NG-CPIP-1, at 21, 154). More specifically, the Company proposes a PBR mechanism with annual distribution rate adjustments established through a revenue cap formula applied only to O&M expenses and comprising the following components: (1) a five-year term with a stay-out provision; (2) an annual composite inflation index based on a weighting of regional and national price indices; (3) an O&M productivity offset, or "X factor" of 0.21 percent; (4) a consumer dividend of 30 basis points to provide a "stretch factor," applicable when inflation equals or exceeds 2.75 percent; (5) a "Y factor" that would provide additional cost recovery for O&M expenses related to capital additions; (6) an ESM; and (7) an exogenous cost provision, or "Z" factor (Exhs. NG-CPIP-1, at 17-31; NG-MM-NC-1, at 12). Each component of the Company's proposed PBR-O mechanism is discussed in more detail below.

2. PBR Mechanism Components

a. PBR-O Plan Term

The Company proposes a five-year plan term and a stay-out commitment of the same length (Exhs. NG-CPIP-1, at 7, 18, 32; NG-MM-NC-1, at 7-8; NG-LRK-1, at 16). The term would begin October 1, 2024, with the first annual rate adjustment thereafter to be effective October 1, 2025, and potential for new base distribution rates to become effective no earlier than October 1, 2029 (Exhs. NG-CPIP-1, at 18, 32; NG-LRK-1, at 16; proposed M.D.P.U. No. 1528,

§ 1.01). Under the Company's proposal, annual compliance filings would be submitted on June 15 each year from 2025 to 2030 (Exh. NG-CPIP-1, at 156).

b. Inflation Index

The Company proposes to base the price inflation index included in the revenue cap formula on a composite index comprising the ECI-Northeast utility labor index, which is a regional labor index of wages paid to private utilities industry workers, and the Producer Price Index for Electric Utilities, which is a national index that addresses non-labor aspects of O&M expense (Exhs. NG-MM-NC-1, at 14; NG-LRK-1, at 8). The Company proposes to weight these indices together on an annual basis by the proportion of the Company's O&M associated with labor and non-labor costs (Exh. NG-MM-NC-1, at 14; RR-DPU-21). Further, the Company proposes a cap of six percent to reflect that this composite index has historically been higher than the Gross Domestic Product Price Index ("GDP-PI") (Exh. NG-CPIP-1, at 160). The Company also proposes a minimum adjustment of 0.21 percent on this inflation factor to create a net adjustment floor of zero percent when combined with the X factor of 0.21 percent (Exhs. NG-CPIP-1, at 160-161; NG-MM-NC-1, at 24).

c. Productivity Offset – X factor

The Company proposes a partial factor productivity offset, or X factor, to be calculated as:

$X = \ln(Y_t/Y_{t-1}) - \ln(X_t/X_{t-1})$, where:

$\ln(Y_t/Y_{t-1})$ is the industry rate of total output growth;

$\ln(X_t/X_{t-1})$ is the industry rate of total input growth; and

X is the O&M adjustment factor ("X factor")

(Exh. NG-MM-NC-1, at 38).

The proposed X factor equals the growth rate of industry outputs minus the growth rate of industry inputs over the period 2008 through 2022 for a sample of 19 utilities in the northeastern United States (Exhs. NG-MM-NC-1, at 24-25; NG-MM-NC-3a & 3b). The proposed X factor applies a revenue cap specifically to O&M expenses, and therefore does not include capital among its inputs (Exh. NG-MM-NC-1, at 24). The Company notes that an O&M adjustment factor in some cases has been called "partial factor productivity," because it does not include all inputs (namely capital) of a Total Factor Productivity ("TFP") study presented in prior PBR filings before the Department (Exh. NG-MM-NC-1, at 19). The inputs included in the X factor calculation are distribution labor, distribution materials, customer accounts and sales labor, customer accounts and sales materials, administrative and general labor, and administrative and general materials (Exh. NG-MM-NC-1, at 24). Because of the O&M-specific nature of the proposed X factor, the Company states that it does not need to utilize a TFP growth differential relative to the broader U.S. economy, because the proposed inflation factor reflects industry input prices only (Exh. NG-MM-NC-1, at 18). Over the 15-year study period, the average O&M adjustment factor value equals 0.21 percent, which serves as the Company's proposed X factor in this case (Exhs. NG-MM-NC-1, at 24; NG-MM-NC-3b at 1).

d. Consumer Dividend

The Company proposes to include a consumer dividend of 30 basis points (or 0.30 percent), to be applied when the inflation factor exceeds 2.75 percent (Exhs. NG-CPIP-1, at 161; NG-LRK-1, at 42; DPU 18-10). The Company states that its proposed consumer dividend is a commitment to sharing incremental cost performance gains with customers in the form of lower rate adjustments (Exh. NG-LRK-1, at 42). The Company's proposed consumer dividend is based on: (1) $40 million of claimed cost savings, which will be passed through to customers in its proposed base distribution rates; (2) the Department's findings on appropriate consumer dividend values since 1997; and (3) the results of four benchmarking studies evaluating National Grid's cost performance from 2019 through 2022 (Exhs. NG-LRK-1, at 43-65; AG 4-51 & Atts.). The proposed consumer dividend represents a reduction from the Company's currently effective consumer dividend of 40 basis points (Exh. NG-LRK-1, at 48).

e. Y Factor

The Company proposes to include a Y factor in its PBR-O adjustment formula to recover incremental operating expenses arising in relation to increased capital expenditures (Exhs. NG-CPIP-1, at 17-18, 23; NG-MM-NC-1, at 19-21; NG-LRK-1, at 15). Initially, the proposed Y factor included two categories of operating expenses. The first category of expenses ("Y1") are the annual capital-related O&M expenses related to core capital expenditures to be recovered under the Company's ISRE mechanism that are not otherwise accounted for as capital costs (Exh. NG-CPIP-1, at 23-24; proposed M.D.P.U. No. 1528, § 3). The Company proposes to limit Y1 recovery to four percent of the cost of actual capital additions, calculated net of the "baseline" capital related O&M expense level established by the Department in the instant proceeding (Exh. NG-CPIP-1, at 24-25). The four-percent cap would be escalated each year by the PBR-O adjustment formula increase (Exh. NG-CPIP-1, at 24). The second category of expenses ("Y2") are the incremental expenses for the labor resources necessary to plan and implement the capital work (Exh. NG-CPIP-1, at 23-24). As part of its rebuttal testimony, however, the Company proposed to eliminate its Y2 category of expenses to reduce complexity and create an inherent stretch factor (Exh. NG-CPIP-Rebuttal-1, at 69-70).

f. Earnings Sharing Mechanism

The Company proposes to implement an ESM that is asymmetric in nature and is consistent with five-year PBR plans previously approved by the Department (Exhs. NG-CPIP-1, at 31; NG-LRK-1, at 13-14; proposed M.D.P.U. No. 1528, § 1.04). 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. NG-CPIP-1, at 31; NG-LRK-1, at 13-14; proposed M.D.P.U. No. 1528, § 1.04). The proposed ESM is asymmetric, in that customers would not be responsible for earnings deficits at any level (Exhs. NG-CPIP-1, at 31; NG-LRK-1, at 13-14). Further, the Company proposes that for any year in which the ROE is above the 100-basis point deadband, the percentage of earnings to be shared with customers would be credited to customers in the following year and the impact of the prior year's adjustment would be excluded from the calculation of the subsequent year's sharing (Exh. NG-CPIP-1, at 31-32; proposed M.D.P.U. No. 1528, § 1.04).

g. Exogenous Cost Factor – Z Factor

National Grid proposes to include in the PBR adjustment formula an exogenous cost provision, or Z factor, which is defined as positive or negative changes to operating costs that, among other things, are beyond the Company's control and not reflected in the O&M composite inflation index or other elements of the PBR adjustment formula (Exhs. NG-CPIP-1, at 27-28; NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1). The Company proposes to calculate the exogenous cost factor as a percentage of the previous year's base revenues (Exh. NG-CPIP-1, at 28).

The Company proposes that to be eligible for exogenous cost recovery the cost change must: (1) be beyond the Company's control; (2) arise from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments; (3) be unique to the electric distribution industry as opposed to the general economy; and (4) meet a threshold of "significance" for qualification (Exhs. NG-CPIP-1, at 27-28; NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1). The Company proposes the significance threshold for exogenous costs to be set for the rate year at $3.6 million, and for the threshold to be adjusted annually by the change in GDP-PI (Exhs. NG-CPIP-1, at 28; NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1). The threshold is based on the product of the Company's operating revenues in the test year of $2,847,886,522 and 0.001253 (Exh. NG-LRK-1, at 14). In addition, National Grid proposes that individual storm events with O&M expense exceeding $30 million may be recovered through the Z factor in the PBR-O mechanism, contingent on a prudence review, provided that the combined balance of the Company's storm fund and any costs associated with the storm event over $30 million exceeds $75 million (Exh. NG-CPIP-1, at 29; proposed M.D.P.U. No. 1528, § 1.05.2).[25]

3. Positions of the Parties

a. Attorney General

The Attorney General argues that PBR and other alternative forms of regulation provide no demonstrable benefits to ratepayers (Attorney General Brief at 16; Attorney General Reply Brief at 3). Specifically, the Attorney General asserts that the Company failed to provide any

[25] The Company's storm fund proposals are discussed in further detail in Section X below.

specific analysis quantifying the benefits to ratepayers from its PBR-O proposal (Attorney General Brief at 16). Further, the Attorney General contends that alternative forms of regulation, such as PBR plans, have resulted in significant rate increases with no corresponding benefits such as increased reliability or SQ (Attorney General Brief at 17). Moreover, the Attorney General claims that National Grid's current PBR plan has failed to increase efficiency as the Company's total costs on a per megawatt hours ("MWh") basis are significantly higher than the regional average and, therefore, the Company has failed to meet its unit cost reduction goals (Attorney General Brief at 17-18; Attorney General Reply Brief at 4-5). The Attorney General recommends that the Department reject the Company's PBR-O proposal in favor of a capital tracker (Attorney General Brief at 18).

Alternatively, the Attorney General argues that if the Department approves a PBR plan for the Company, the Department should modify several of the proposed components of the plan. First, the Attorney General challenges the Company's proposed composite inflation index. The Attorney General argues that the weighted average indices proposed by the Company are "cherry-picked" to maximize PBR rate adjustments and that no composite index similar to one proposed by the Company previously has been approved by a U.S. regulator (Attorney General Brief at 22). The Attorney General recommends that, if the Department approves a PBR mechanism, it should reject the Company's proposed composite inflation index and instead use GDP-PI as the appropriate inflation measure (Attorney General Brief at 22; Attorney General Reply Brief at 7).

Second, the Attorney General takes issue with the Company's proposed X factor of 0.21 percent (Attorney General Brief at 21-22). The Attorney General argues that productivity estimates, in general, are not robust as small changes in input data, time period, and output measures can cause large fluctuations in results (Attorney General Brief at 22). Further, the Attorney General contends that the limitations associated with productivity estimates are magnified by the Company's use of partial factor productivity, rather than a more traditional TFP study (Attorney General Brief at 22-23). The Attorney General recommends that, if the Department approves a PBR mechanism, it should reject the Company's proposed X factor and rather than approving any X factor, instead approve a "more generous" consumer dividend adjustment, as discussed below (Attorney General Brief at 23).

Third, the Attorney General takes issue with the Company's proposed consumer dividend. The Attorney General contends that the Company's cost performance has degraded as costs per MWh have increased from 14.4 percent above the regional peer average in 2019 to 17.7 percent higher than the regional peer average in 2022 (Attorney General Brief at 24; Attorney General Reply Brief at 8). Thus, the Attorney General asserts that, should the Department approve a PBR mechanism, the consumer dividend should be increased from the Company's proposed 30 basis points to 50 basis points, in conjunction with a reduced X factor (Attorney General Brief at 23-24).

Fourth, the Attorney General argues that the Company's proposed Y factor runs counter to both theoretical and empirical expectations (Attorney General Brief at 18-19). More specifically, the Attorney General contends that capital investments are expected to streamline operations, raise efficiency, and reduce response and repair times (Attorney General Brief at 19). Thus, according to the Attorney General, capital and O&M expenses are expected to be negatively correlated, so that expected reductions in O&M expense render a Y factor adjustment unnecessary (Attorney General Brief at 18-19). The Attorney General further argues that the Y factor is not supported by empirical evidence, and she points to weak negative correlation between distribution plant and O&M expenses, for both the Company and the northeast peer group (Attorney General Brief at 19, citing Exhs. AG-DED-1, at 15; AG-DED-3, Sch. 2). Further, the Attorney General cites to the Department's approval of O&M offsets in natural gas pipeline replacement proposals as support for the proposition that increased capital investment results in reduced O&M expense (Attorney General Brief at 19-20 & n.79, citing Bay State Gas Company, D.P.U. 13-75, at 57-58 (2014); D.P.U. 12-25, at 60; D.P.U. 10-114, at 70-71; D.P.U. 10-55, at 138; D.P.U. 09-30, at 120). The Attorney General contends that the Company's proposed Y factor will not encourage disciplined operational spending, as it will function as a dollar-for-dollar recovery mechanism for all expenses that exceed baseline levels (Attorney General Brief at 20). The Attorney General recommends that, if the Department approves a PBR mechanism, it should reject the Company's proposed Y factor (Attorney General Brief at 20).

Finally, the Attorney General addresses the Company's proposed ESM. The Attorney General argues the proposed ESM is, in practicality, meaningless because no Massachusetts utility to date has ever shared excess earnings (Attorney General Brief at 24). She also notes that there is nothing to prevent the Company from breaking its five-year stay-out commitment (Attorney General Brief at 24 & n.100, citing D.P.U. 17-05, at 403-404). The Attorney General asserts that should the Department approve a PBR mechanism, the ESM and stay-out provisions should be rejected in favor of the higher consumer divided (Attorney General Brief at 13, 24, 41).

b. DOER

DOER argues that the Company has not met the burden of demonstrating that its PBR-O plan is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote economic efficiency, cost control, lower rates, and reduced administrative burden (DOER Brief at 19, 21, citing Incentive Regulation, D.P.U. 94-158, at 57 (1995)). DOER asserts that National Grid's decision to bifurcate O&M-related recovery and capital-related recovery decreases the Company's incentive to efficiently operate using the least-cost combination of labor, capital, and other inputs (DOER Brief at 20). DOER further argues that the Company has failed to substantiate that the PBR-O mechanism will lead to greater operational efficiency than traditional cost of service regulation (DOER Brief at 21). For these reasons, DOER asserts that the proposed PBR-O plan is not in the public interest (DOER Brief at 19-21).

DOER also argues that National Grid's five-year stay-out provision is a hollow consumer protection because there is nothing that prevents the Company from breaking its commitment (DOER Reply Brief at 5, citing Attorney General Brief at 13, 24, 41). Further, DOER contends that any benefits of the stay-out provision are lessened because: (1) the PBR-O plan applies exclusively to O&M costs, while the substantial capital expenses are not meaningfully controlled because of the capital cost recovery mechanism; and (2) the Company's requested reconciliation mechanisms require additional regulatory proceedings that diminish the purported administrative efficiency of a PBR-style plan (DOER Reply Brief at 5). Additionally, DOER claims that given the timing of advanced metering infrastructure ("AMI") implementation, the five-year stay-out provision may limit the Company's ability to implement recommendations or seek Department approval for particular actions, thereby preventing impactful rate changes enabled by AMI (DOER Reply Brief at 6).

c. Acadia Center

Acadia Center argues that the general PBR framework used in the Commonwealth has become too complicated as the number of factors used in PBR adjustment formulas, and the complexity of the methodology of setting the values for them, have continued to increase (Acadia Center Brief at 22). Acadia Center contends that the Department should open an investigation to improve upon or streamline the PBR methodology (Acadia Center Brief at 22). In the instant proceeding, Acadia Center requests that the Department consider methods to simplify PBR processes and construct robust guardrails against unnecessary rate increases (Acadia Center Brief at 22).

d. MEDA

MEDA takes issue with the Company's proposed ESM and argues that allowing the Company to retain 100 percent of earnings up to 100 basis points above the allowed ROE is too favorable to shareholders (MEDA Brief at 51; MEDA Reply Brief at 23-24). MEDA also contends that allowing the Company to retain 25 percent of earnings above the deadband is also too favorable to shareholders (MEDA Brief at 51). According to MEDA, the proposed ESM impermissibly allows the Company to retain a level of profit in excess of what is necessary to cover its costs and earn a fair return, contrary to past precedent (MEDA Reply Brief at 23-24, citing Boston Gas Company V. Department of Public Utilities, 387 Mass. 531, 539 (1982); Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 680, 692 (1923) ("Bluefield")). Finally, MEDA asserts that the inequities in the proposed ESM structure emphasize the need to rely on effective metrics to deliver benefits of a PBR plan to customers (MEDA Brief at 51-52).

e. Company

The Company argues that its PBR-O proposal uses a mix of incentive-based mechanisms to promote distinct, but complementary, Department objectives (Company Brief at 116, citing Exh. NG-LRK-1, at 40). In particular, the Company contends that the proposed PBR-O plan establishes an incentive-based framework for achieving both traditional regulatory aims and newer goals centered on the deployment of clean energy (Company Brief at 116, citing Exh. NG-LRK-1, at 40-41). According to the Company, the PBR-O plan is appropriate because excessive reliance on what it considers to be burdensome, inflexible cost-of-service ratemaking is not well-suited to the modernized, more flexible, and decentralized energy marketplace contemplated by the Department in recent years (Company Brief at 116, citing Exh. NG-LRK-1, at 40-41).

With respect to the components of its proposed PBR-O plan and the various Intervenor positions, the Company argues that the proposed five-year stay-out provision will instill a strong incentive for cost control, reduce administrative burden, and allow for the necessary flexibility to adjust the timing for investments (Company Brief at 157). Further, National Grid contends that a stay-out shifts risks from customers to the Company, as it seeks to avoid incurring any penalties associated with breaking its stay-out provision (Company Brief at 158). In addition, National Grid maintains that a five-year PBR plan term allows the Company to take a long-term approach to its supply chain, which leads to efficiency improvements that ultimately result in lower costs to ratepayers (Company Brief at 158). National Grid also argues that approving the five-year stay-out provision is critical as it will enable the Company to plan and execute projects in an efficient manner and will aid in optimizing spending for capital projects (Company Brief at 259). Finally, the Company asserts that the five-year stay-out is consistent with Department precedent and that the Department has previously found that a stay-out of this length will enhance performance incentives and encourage long-term planning (Company Brief at 259-260, citing D.P.U. 17-05, at 302-303). For these reasons, the Company dismisses the Attorney General's contention that the five-year stay-out provision should be rejected (Company Brief at 258).

The Company argues that its proposed composite inflation index should be approved rather than use the GDP-PI index as proposed by the Attorney General (Company Brief at 256). The Company contends that GDP-PI is appropriate to capture the prices of goods and services made with labor, materials, and capital, but is not useful for an O&M-specific adjustment like the PBR-O plan (Company Brief at 256). The Company claims that the Attorney General's recommendation to use GDP-PI reflects deference to legal precedent rather than economic theory (Company Brief at 256).

Next, the Company argues that its proposed 0.21 percent X factor should be retained, as it is an accurate representation of O&M partial factor productivity growth and that the Attorney General has not provided a compelling reason to set the X factor at zero (Company Brief at 256-257). The Company contends that because its proposed PBR mechanism applies only to O&M expenses, it is not appropriate to rely on recent precedent, particularly NSTAR Electric's and Unitil's recent base distribution rate cases where the X factor was set to zero, to set the X factor in this case (Company Brief at 257). Further, the Company maintains that its proposed X factor is dependent on the proposed inflation factor, which is different in this case than those recent cases (Company Brief at 257). Additionally, National Grid asserts that NSTAR Electric's and Unitil's approved PBR plans offered a zero percent X factors to counterbalance the approval of a K-bar mechanism for capital cost recovery, which the Company is not proposing to do in this case (Company Brief at 257).

The Company also rejects the Attorney General's arguments with respect to the proposed Y factor. In particular, the Company argues that the Y factor is necessary because it will account for additional O&M expenses that are a direct result of increased capital additions (Company Brief at 253-254). The Company asserts that the proposed Y factor would not create an incentive to overspend or over capitalize because of the ISRE mechanism investment cap (Company Brief at 254). Further, the Company contends that the Attorney General's basis for rejecting the Y factor is theoretical and not supported by empirical data (Company Brief at 253, citing Exh. NG-LRK-Rebuttal-1, at 24-29). In addition, the Company contends that similar factors are common practice in PBR plans in other jurisdictions, and that this mainstream acceptance of the need for such a factor is supportive of its inclusion in the proposed PBR-O plan (Company Brief at 254).

Regarding its proposed consumer divided, National Grid reiterated on brief that 30 basis points is appropriate given the $40 million in claimed cost savings that will be passed through to customers, Department findings relative to past consumer dividends, and the Company's cost performance since 2019 (Company Brief at 131-147). The Company argues that the Attorney General's recommendation of a 50-basis point consumer dividend is inconsistent with Department precedent and not supported by empirical evidence (Company Brief at 257-258, citing Exh. NG-LRK-Rebuttal-1, at 50-55). In particular, the Company argues that the Attorney

General's recommendation discounts over 20 years of Department precedent on the topic, benchmarking evidence, and research (Company Brief at 258, citing Exh. NG-LRK-Rebuttal-1, at 50-55).

National Grid argues that its proposed ESM serves as a measure that protects ratepayers by ensuring they will share in the benefits if the Company over earns (Company Brief at 165). National Grid asserts that the proposed ESM aligns with prior Department precedent, in that it is asymmetric in nature and does not provide the Company with downside sharing (Company Brief at 165). Thus, the Company maintains that the ESM proposal will: (1) create strong incentives to pursue additional earnings; (2) give ratepayers a considerable stake in higher earnings; and (3) protect ratepayers from levels of earnings that could be considered unreasonable (Company Brief at 166, citing Exh. NG-LRK-1, at 66). The Company asserts that, contrary to the Attorney General's argument, the lack of any previous earnings sharing by utilities with customers is a testament to the challenges that come with an extended stay-out period, as the goal should not be to produce overearnings, but rather to force efficiency as the utility attempts to sustain its financial integrity during the PBR plan term (Company Brief at 258). National Grid argues that allowing it to retain higher earnings is an incentive to pursue new earnings opportunities, but that the design of the ESM ensures that customers share in such benefits and are protected against sizable overearning (Company Reply Brief at 33).

Regarding DOER's assertion that the PBR-O mechanism should be rejected because it differs significantly from traditional PBR plans, the Company argues that the PBR-O plan follows the basic "inflation minus productivity" mechanism that the Department has supported for many years, and that the only difference is the application of the mechanism solely to O&M

costs rather than both capital and O&M expenses (Company Brief at 260-261). Further, the Company contends that capital costs have grown to the extent that an index-based revenue increase cannot keep pace with them, so the application of a traditional PBR plan to capital costs is not possible (Company Brief at 260-261).

Finally, the Company supports Acadia Center's recommendation to open a proceeding to examine regulatory adjustments that may help simplify and focus regulation going forward (Company Brief at 261). National Grid, however, rejects any notion that because PBR plans are growing in complexity, the Company's plan in this proceeding should not be approved (Company Brief at 261). The Company asserts that the complexity of its proposed PBR plan reflects the complex circumstances it currently faces (Company Brief at 261).

4. Analysis and Findings

a. 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 plans as an adjustment to cost of service/rate of return regulation. Further, we discuss the factors that the Department has applied to review incentive regulation proposals. Finally, we review the Company's proposed PBR-O plan, and make findings on whether allowing its PBR-O plan is in the public interest and will result in just and reasonable rates.

b. Department Ratemaking Authority

Pursuant to G.L. c. 164, § 94, the Legislature has granted the Department extensive ratemaking authority over EDCs and LDCs. The Supreme Judicial Court has consistently found that the Department's authority to design and set rates is broad and substantial. See, e.g., Boston

Real Estate Board v. Department of Public Utilities, 334 Mass. 477, 485 (1956). Because G.L. c. 164, § 94 authorizes the Department to regulate the rates, prices, and charges that EDCs and LDCs may collect, this authority includes the power to implement revenue adjustment mechanisms such as a PBR mechanism. 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 plan 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).

In addition, G.L. c. 164, § 76, grants the Department broad supervision over EDCs and LDCs. Under G.L. c. 164, § 76C, the Department has the authority to establish reasonable rules and regulations consistent with G.L. c. 164, as needed, to carry out its administration of jurisdictional companies in the public interest. 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 over time. D.P.U. 07-50, at 8. Over the years, EDCs and LDCs subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See, e.g., D.P.U. 23-80/D.P.U. 23-81, at 34; D.P.U. 22-22, at 80-81; D.P.U. 20-120, at 102-103; D.P.U. 19-120, at 58; D.P.U. 18-150, at 47; D.P.U. 17-05, at 371-372; D.T.E. 05-27, at 382; 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 plans 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 plans as a meaningful regulatory format.

c. Evaluation Criteria for PBR Plan

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

As part of our investigation of incentive ratemaking, the Department examined the criteria to evaluate PBR proposals for EDCs and LDCs. D.P.U. 94-158, at 52-66. The Department found that, because incentive regulation acts as an alternative to traditional cost of service regulation, incentive proposals would be subject to the standard of review established by G.L. c. 164, § 94, which requires that rates be just and reasonable. D.P.U. 94-158, at 52; Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256 n.13 (2002) (in determining propriety of rates under G.L. c. 164, § 94, Department must find that rates are just and reasonable). Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like a PBR plan 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 we 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.

d. Rationale for PBR-O Plan

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 distributed generation ("DG"), and the procurement of long-term contracts for renewable energy. See, e.g., An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179, § 68 ("2022 Clean Energy Act"); An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8, § 87 ("2021 Climate Act"); The Massachusetts 2050 Decarbonization Roadmap;[26] 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

[26] 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).

Climate Change Strategy for the Commonwealth (September 16, 2016). This evolution is changing the operating environment for EDCs in Massachusetts.

As described above, National Grid proposes to continue operating under a PBR plan for the next five years (Exhs. NG-CPIP-1, at 7, 18; NG-MM-NC-1, at 7-8; NG-LRK-1, at 16). In addition to the arguments set forth above, the Company states that it must address a dynamic operating environment involving changing technologies, increasing frequency and intensity of storms, higher customer expectations, lost sales growth, and the need to plan and construct the capital additions that will support the Commonwealth's clean energy transition (Exh. NG-CPIP-1, at 16-17). Further, the Company notes that it is planning for the future with a particular focus on building capabilities to meet future service requirements in an electrified environment (Exh. NG-CPIP-1, at 19). According to National Grid, the PBR-O plan is a critical factor that will enable it to focus on operations and to meet expectations (Exh. NG-CPIP-1, at 163). In addition, National Grid submits that the PBR-O plan creates incentives for cost control, allows the Company to maintain financial flexibility during the stay-out, and allows the Company to focus on its service and customer obligations without the need for administratively burdensome base distribution rate cases (Exh. NG-CPIP-1, at 154). Further, National Grid expects that without the PBR-O mechanism, it would not be able to commit to the five-year stay-out provision (Exh. NG-CPIP-1, at 163). National Grid has made various estimates of the number of base distribution rate cases it would file without the PBR-O plan, ranging from one to five filings through 2029 (Exhs. NG-LRK-1, at 36-37; DPU 18-9; DPU 34-6; AG 4-31).

As discussed above, the Attorney General argues that National Grid's PBR-O proposal should be rejected because the Company failed to provide any specific analysis quantifying the benefits to ratepayers from its PBR-O proposal and that PBR plans, including the Company's current plan, have resulted in significant rate increases with no corresponding benefits such as increased reliability or SQ goals (Attorney General Brief at 17-18; Attorney General Reply Brief at 4-5). DOER contends that the proposed PBR-O plan is not in the public interest, while Acadia Center recommends opening a separate proceeding to examine PBR plans (DOER Brief at 19-21; Acadia Center Brief at 22). These Intervenors, as well as MEDA, recommend changes to the Company's PBR-O mechanism should the Department approve a PBR plan.

The Department finds that the Company has demonstrated that continuing its PBR plan in the form of a PBR-O plan is an appropriate alternative to traditional cost of service/rate of return ratemaking. From 2020 through 2023, under the current PBR plan term approved in D.P.U. 18-150, and after the termination of its CIRM at the end of calendar year 2019, the Company made over $1.0 billion in base capital and facilities investments, solely through the PBR mechanism. Facilitated by the current PBR mechanism, the Company instituted a variety of cost containment initiatives, including implementation of robotic process automation; using web-based solutions to streamline and automate customer service processes; fleet standardization; strategic contract management; leveraging of supply chain partnerships and use of contractors of choice for engineering work; and general process improvements (Exhs. NG-CPIP-9; DPU 28-3, Att.). In addition, we find that National Grid has demonstrated that the current PBR plan has been effective in maintaining rate stability and delivery price predictability, as well as avoiding relatively larger rate changes.

The Department finds that allowing National Grid to continue to operate under a PBR plan will provide the Company more flexibility in 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. NG-CPIP-1, at 16, 19; NG-LRK-1, at 5-6). Further, through the stay-out provision, the Company has committed to refraining from filing rate schedules to put new base distribution rates into effect during the PBR-O plan's term (Exhs. NG-CPIP-1, at 7, 18; NG-MM-NC-1, at 7-8; NG-LRK-1, at 16). The Department accepts that this stay-out provision will result in efficiencies and diminished administrative burden (Exh. NG-CPIP-1, at 154). In addition, the Department finds that, in this instance, a PBR plan for O&M expenses, in tandem with the ISRE mechanism, is better suited to satisfy the Department's public policy goals and statutory obligations than the Attorney General's proposed use of an all-in capital tracker.

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

e. PBR-O Plan Components

i. PBR-O Plan Term

The Company proposes a five-year PBR-O plan term (Exhs. NG-CPIP-1, at 7, 18; NG-MM-NC-1, at 7-8; NG-LRK-1, at 16). The five-year term would commence on October 1, 2024, and expire on October 1, 2029, during which there would be four annual PBR-O mechanism adjustments, taking effect each October 1, beginning in 2025 (Exhs. NG-CPIP-1, at 18, 32; NG-LRK-1, at 16; proposed M.D.P.U. No. 1528, § 1.01). In conjunction with the PBR-O plan term, National Grid proposed a stay-out provision whereby the Company commits to not file a base distribution rate case during the PBR-O plan term that would result in new base distribution rates going into effect prior to October 1, 2029 (Exh. NG-CPIP-1, at 18, 32).

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 longer-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. 23-80/D.P.U. 23-81, at 37 (five years); D.P.U. 22-22, at 54 (five years, with a possible five-year extension); D.P.U. 20-120, at 72 (five years); D.P.U. 19-120, at 65 (ten years); D.P.U. 18-150, at 56 (five years); D.P.U. 17-05, at 404 (five years); D.T.E. 05-27, at 399 (ten years); D.T.E. 03-40, at 495-496 (ten years); D.T.E. 01-56, at 10 (ten years); D.P.U. 96-50 (Phase I) at 320 (five years).

As noted above, the Company intends to undertake substantial capital investments over the next five-year period to meet the Commonwealth's clean energy transition goals of increased electrification and decarbonization, as well as to maintain safe and reliable service (Exhs. NG-CPIP-1, at 34; NG-BJM-1, at 20; AG 4-31). Based on the specific circumstances presented in this case, the Department concludes that a five-year PBR-O plan term will allow for the planning, resources, and flexibility necessary for the Company to adjust its operations and investments efficiently and, in turn, best ensures ratepayer benefits of increased operational efficiencies and improved service, and the opportunity for avoided administrative costs. The Department therefore approves a PBR-O plan term of five years for National Grid. In addition, a stay-out provision provides the important benefit to ratepayers of ensuring strong incentives for cost containment under the PBR-O plan. D.P.U. 23-80/D.P.U. 23-81, at 37; D.P.U. 22-22, at 55; D.P.U. 19-120, at 65; D.P.U. 18-150, at 55; D.P.U. 17-05, at 403. Accordingly, the Department adopts a stay-out provision in conjunction with the five-year term.

The Attorney General and DOER argue that the Department should reject the stay-out provision, as it provides no benefit to ratepayers since there is nothing preventing the Company from breaking it (Attorney General Brief at 13, 24, 41; DOER Reply Brief at 5). The Department has made it clear that companies operating under a PBR plan are expected to refrain from seeking changes to base distribution rates outside of the annual PBR adjustments mechanism. See, e.g., D.P.U. 94-158, at 22. General base distribution rate changes are usually reviewed in general rate cases pursuant to G.L. c. 164, § 94. See, e.g., Massachusetts-American Water Company, D.P.U. 95-118, at 175 (1996); Housatonic Water Works Company, D.P.U. 95-81, at 3 (1996); Commonwealth Gas Company, D.P.U. 92-151, at 4 (1992); Boston

Edison Company, D.P.U. 92-23/92-24, at 4 (1992); Tax Reform Act, D.P.U. 87-21-A at 6-7. When approving long-term PBR plans, the Department has taken note of opportunities available to companies to change rates under such plans. These opportunities have included a formal mid-period review and acknowledgment that companies retain the option to petition the Department for changes in tariffed rates in reaction to extraordinary economic conditions. D.T.E. 05-27, at 400; D.T.E. 03-40, at 497 & n.263; D.T.E. 01-56, at 10-11. The Department, however, notes that the two prior instances of utilities establishing new base distribution rates during the term of an existing PBR plan were prompted by the Department's acceptance of revenue decoupling and our expressed goal to avoid the implementation of decoupling in a piecemeal fashion, i.e., by permitting distribution companies to layer decoupling proposals on top of existing rates. D.P.U. 10-55, at 12-16; D.P.U. 09-30, at 19-25; D.P.U. 07-50-A at 81-82. Further, National Grid is currently operating under a PBR mechanism, with a five-year stay-out, which the Company has not broken, despite several years of earned rates of return that fall below allowed rates of return (Exh. NG-CPIP-Rebuttal-1, at 20). Based on these considerations, we are not persuaded by the Attorney General's and DOER's arguments to deny the proposed stay-out provision.

ii. Inflation Index

The Company proposes an inflation index based on a weighted composite index comprising the ECI-Northeast utility labor index and the Producer Price Index for Electric Utilities (Exhs. NG-MM-NC-1, at 14; NG-LRK-1, at 8). Further, the Company proposes a cap of six percent to reflect that this composite index has historically been higher than GDP-PI (Exh. NG-CPIP-1, at 160). The Company also proposes a minimum adjustment of 0.21 percent on this inflation factor to create a net adjustment floor of zero percent when combined with the X factor of 0.21 percent (Exhs. NG-CPIP-1, at 160-161; NG-MM-NC-1, at 24). The Attorney General argues that the weighted average indices proposed by the Company are designed to maximize PBR rate adjustments, and that the proposal should be rejected and replaced with an inflation index based on GDP-PI (Attorney General Brief at 22; Attorney General Reply Brief at 7).

In D.P.U. 94-50, at 141, the Department found that the GDP-PI is the most accurate and relevant measure of output price changes for the bundle of goods and services the TFP growth of which is measured by the Bureau of Labor Statistics. In addition, the Department found that GDP-PI is: (1) readily available; (2) more stable than other inflation measures; and (3) maintained on a timely basis. D.P.U. 94-50, at 141. The Department has approved prior PBR plans using GDP-PI as the appropriate inflation index for the adjustment mechanism. See, e.g., D.P.U. 23-80/D.P.U. 23-81, at 40; D.P.U. 22-22, at 57; D.P.U. 20-120, at 31; D.P.U. 19-120, at 21; D.P.U. 18-150, at 8; D.P.U. 17-05, at 393; D.T.E. 05-27, at 384; D.T.E. 03-40, at 473; D.T.E. 01-56, at 20. Notwithstanding these prior decisions, the Department finds that the Company's proposed use of the ECI-Northeast utility labor index and the Producer Price Index for Electric Utilities meets the standards of availability, as both are made freely available and published by the Bureau of Labor Statistics (Exh. NG-MM-NC-1, at 14 & nn.21, 21). Further, we find that the Company's proposed composite inflation index is of comparative historical stability to GDP-PI (Exh. NG-MM-ÑC-1, at 22). Additionally, both indices are maintained on a timely basis, as they are both updated at least quarterly (Exh. NG-MM-NC-1, at 14 & nn.20, 21).

Moreover, the Department is satisfied the Company's proposed composite inflation index provides an accurate and relevant measure of utility-specific O&M-related input price changes that are used in the Company's calculation of the partial factor productivity (Exhs. NG-MM-NC-1, at 14; NG-LRK-1, at 8; DPU 18-1; DPU 18-3 & Att.; AG 4-38 (Supp.) & Att.). The Department determines that, under the framework of an O&M-specific PBR-O adjustment, it is not appropriate to use a capital-inclusive measure of economy-wide inflation, such as GDP-PI. The Department recognizes that a utility-specific measure of O&M expense, like the one proposed, is likely to provide a more accurate representation of the inflationary pressures that are placed on the Company's operational expenses. Accordingly, the Department approves the Company's proposed inflation factor.

As noted, the Company also proposes a cap on the inflation measure of six percent, to reflect that the proposed composite index historically has been higher than the GDP-PI (Exh. NG-CPIP-1, at 160). The Company also proposes to implement a "floor" for the inflation measure of 0.21 percent, which would provide an effective PBR-O adjustment floor of zero (Exh. NG-CPIP-1, at 160-161). The Department has previously found that inflation caps on PBR adjustments are appropriate, particularly when coupled with a PBR adjustment floor, which ensures the utility will not experience a negative adjustment. D.P.U. 23-80/D.P.U. 23-81, at 40-41; D.P.U. 22-22, at 57-58. The Department found that inflation caps of five percent provide an important consumer protection in the event of high levels of inflation. D.P.U. 23-80/D.P.U. 23-81, at 40-41; D.P.U. 22-22, at 57-58. The Department is not convinced that the Company's proposed inflation index will be sufficiently higher than what has historically been measured by GDP-PI to justify an increase in the inflation ceiling of one percent

(Exhs. NG-MM-NC-1, at 22-23; DPU 18-6). We find the Company's proposed six percent cap on the composite inflation index would shift too much risk to ratepayers. Accordingly, we direct the Company to set a cap on its inflation factor of five percent. The Department also finds that an inflation floor of 0.21 percent, to correspond with the approved X factor discussed below, is a reasonable component of the PBR-O mechanism. Accordingly, the Department approves a five percent cap on the composite inflation index and an inflation floor of 0.21 percent for the Company.

iii. Productivity Offset – X factor

As described above, the Company proposes an X factor of 0.21 percent based on a partial factor productivity, as the PBR-O mechanism applies only to O&M expense (Exhs. NG-MM-NC-1, at 24; NG-MM-NC-3b, at 1). In the context of a PBR mechanism that uses an economy-wide measure of inflation, a productivity offset consists of the differential in expected productivity growth between the electric distribution industry and the overall economy, and the differential in expected input price growth between the overall economy and the electric distribution industry (Exh. NG-MM-NC-1, at 23). The Company's proposed PBR-O mechanism, however, does not use an economy-wide measure of inflation, instead using a composite measure based on the ECI-Northeast utility labor index and the Producer Price Index for Electric Utilities to create a utility O&M-specific measure of inflation (Exh. NG-MM-NC-1, at 14). The Company accordingly removes capital inputs from the partial productivity factor calculation (Exh. NG-MM-NC-1, at 18). The result is an X factor calculation that is less complex than the standard TFP and price differentials used in prior PBR plans in the

Commonwealth and is measured as the change in industry outputs (growth in customers) minus the change in industry inputs over the 15-year period (Exh. NG-MM-NC-1, at 18).

No parties contest the sample size of 19 utilities in the northeastern United States or the time period of 2008 through 2022 that is used in the Company's O&M adjustment factor calculation. As noted, the Attorney General, in general, argues that productivity estimates are not reliable, and that the Department should not approve any X factor, and instead approve a higher consumer dividend adjustment (Attorney General Brief at 23). The Department historically has relied on productivity offsets based on a TFP study when designating an appropriate X factor under a PBR plan. See, e.g., D.P.U. 20-120, at 82-83; D.P.U. 19-120, at 84; D.P.U. 18-150, at 60; D.P.U. 17-05, at 391-392; D.T.E. 05-27, at 386; D.T.E. 03-40, at 477; D.P.U. 96-50 (Phase I) at 263. In this instant proceeding, however, because the inflation index reflects only industry input price and not output price changes in the broader U.S. economy, we find it unnecessary to calculate an X factor that demonstrates the growth differential between the electric distribution industry and the broader U.S. economy (Exh. NG-MM-NC-1, at 18). Further, because the PBR-O plan applies only to O&M expense, it stands to reason that the X factor would be different from those in prior cases, particularly those cases in which negative X factors were approved (Exhs. NG-MM-NC-1, at 18-19; DPU 18-7). Moreover, we note that the zero X factors approved for NSTAR Electric and Unitil were proposed in conjunction with the approval of a K-bar adjustment[27] in their PBR plans and were not necessarily based on

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[27] As explained in D.P.U. 23-80/D.P.U. 23-81, at 13 n.10 and D.P.U. 22-22, at 20 n.21, in 2016, the Alberta Utilities Commission developed a "K-bar" approach to supplemental capital funding for Alberta EDCs. The Alberta Utilities Commission amended its K-bar method in 2018. Under this approach, the I-X PBR formula escalates historical average

compelling economic theory or empirical analysis. D.P.U. 23-80/D.P.U. 23-81, at 39-40; D.P.U. 22-22, at 56-57.

We have reviewed the record concerning the Company's development of the X factor, and we find the use of an X factor of 0.21 percent in the PBR-O adjustment formula to be reasonable (see, e.g., Exhs. NG-MM-NC-1, at 18-19, 24; NG-MM-NC-3a & 3b; DPU 18-1 through DPU 18-5 & Atts.; DPU 18-7; DPU 18-8; AG 4-39; AG 4-40). Accordingly, we approve an X factor of 0.21 percent.

iv. Consumer Dividend

The consumer dividend is intended to reflect expected future gains in productivity due to the move from cost-of-service regulation to incentive regulation. D.P.U. 96-50 (Phase I) at 165-166. As a deduction to the PBR-O adjustment, the consumer dividend is designed to allow ratepayers to share in these aforementioned gains (Exh. NG-LRK-1, at 42). National Grid proposes to apply a consumer dividend of 30 basis points (or 0.30 percent) when inflation exceeds 2.75 percent (Exhs. NG-CPIP-1, at 161; NG-LRK-1, at 42). The Company's proposed consumer dividend is based on: (1) $40 million of claimed cost savings, which will be passed through to customers in its proposed base distribution rates; (2) the Department's findings on appropriate consumer dividend values since 1997, which showed approved consumer dividends in the range of 15 percent and 50 percent; and (3) the results of four benchmarking studies

capital additions not subject to recovery through capital trackers to form the basis of future approved capital recovery. 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. The Alberta Utilities Commission calls this differential the "K-bar."

evaluating National Grid's cost performance from 2019 through 2022, which showed that since the Department's Order in D.P.U. 18-150, the Company has kept its unit costs between 10.4 percent and 10.8 percent below the unit costs of the Northeast electric distribution industry (Exhs. NG-LRK-1, at 43-65; AG 4-51 & Atts.).

The Attorney General argues that the Company's costs since its last base distribution rate case are higher than the regional peer average and that the consumer dividend should be raised to 50 basis points in exchange for the removal of the X factor, five-year stay-out commitment, and ESM (Attorney General Brief at 23-24). In the sections above and below, Department approves an X factor of 0.21 percent, a five-year stay-out provision, and an ESM. Based on these considerations, the Department rejects the Attorney General's recommended consumer dividend of 50 basis points. The Department, however, is not persuaded that the Company's proposed consumer dividend is appropriate.

The Company currently operates under a PBR plan that contains stipulations for a possible reduction in its currently effective 40 basis point (or 0.40 percent) consumer dividend, depending on cost performance. D.P.U. 18-150, at 63. While the Company has made gains in cost performance, as noted above, it fell short of the performance targets necessary for a reduction in its consumer dividend (Exh. NG-LRK-1, at 62). Cost benchmarking in D.P.U. 18-150 determined the Company to be an average cost performer, and the Company has not made gains significant enough to exceed this determined average performance (Exh. NG-LRK-1, at 62-63). Further, the Company recognizes that the Department has found that a consumer dividend of approximately 0.40 percent to be appropriate for average cost performance (Exh. NG-LRK-1, at 53-54, citing D.T.E. 05-27, at 393). In addition, the

Department is not convinced that the Company's estimated $40 million in cost savings claimed to be included in its proposed distribution rates is alone sufficient to warrant a reduction in the consumer dividend as the Company's cost performance overall has not substantially improved (Exh. NG-AG 1-21).

We also note that the PBR-O mechanism is different in design from any PBR plan previously approved by the Department. In prior PBR plans, the consumer dividend applied to the overall increase to base revenues, which included capital expenditures. The Company's PBR-O plan, and therefore its consumer dividend, applies only to O&M expenses. Thus, to maintain a sufficient level of customer benefits accruing from the PBR-O mechanism, we conclude that the consumer dividend should be more aggressive than proposed. Based on the above considerations, we find that maintaining the consumer dividend at 40 basis points (or 0.40 percent) appropriately reflects the Company's cost performance and provides a reasonable opportunity for customers to share in future gains in productivity resulting from the PBR-O mechanism. Accordingly, the Department rejects the Company's proposed consumer dividend of 0.30 percent and directs the Company to use a consumer dividend of 0.40 percent.

Regarding the inflation contingency component of the consumer dividend, the Department directs National Grid to adopt a more stringent approach. The Company initially developed the threshold of 2.75 percent largely based on judgment, with subsequent research showing that a consumer dividend with a 2.75 percent threshold based on the composite inflation index would apply roughly as often as a consumer dividend with a threshold of two percent based on the GDP-PI (Exhs. DPU 18-10; DPU 33-10; Tr. 7, at 925-926; RR-AG-20). Given the five percent inflation cap approved above, the Department is not convinced that the rate of inflation provided by the composite index is sufficiently higher than the GDP-PI rate of inflation to warrant an increase in the inflation threshold for the consumer dividend (Exhs. NG-MM-NC-1, at 22-23; DPU 18-6). Accordingly, the Department directs the Company to lower its inflation threshold for the consumer dividend applicability threshold to two percent.

v. Y Factor

As noted above, the Company proposes to include a Y factor in its PBR-O adjustment formula to recover incremental operating expenses arising in relation to increased capital expenditures (Exhs. NG-CPIP-1, at 17-18, 23; NG-MM-NC-1, at 19-21; NG-LRK-1, at 15). Specifically, the Y factor would recover the annual capital-related O&M expenses related to core capital expenditures to be recovered under the Company's ISRE mechanism that are not otherwise capitalized (Exh. NG-CPIP-1, at 23-24; proposed M.D.P.U. No. 1528, § 3). The Attorney General argues that because capital and O&M expenses are expected to be negatively correlated, expected reductions in O&M expense render a Y factor adjustment unnecessary (Attorney General Brief at 18-19). Further, the Attorney General contends that the Y factor is not supported by empirical evidence, and she points to weak negative correlation between distribution plant and O&M expenses, for both the Company and the northeast peer group (Attorney General Brief at 19, citing Exhs. AG-DED-1, at 15; AG-DED-3, Sch. 2).

The Department recognizes that the Company is undergoing a significant step change in capital investment requirements (Exhs. NG-CPIP-1, at 159-160; NG-LRK-1, at 5-6; AG 4-31). Nevertheless, the Company acknowledges that the relationship between O&M expense and capital investment is not entirely clear, and that there are many instances where capital spending can reduce the need for O&M spending (Exh. NG-LRK-1, at 29). Furthermore, much of the

Company's expected capital investments are in the areas of modernization and core investments, which are areas of investment that would be expected to streamline operations, increase efficiency, reduce response times for outages, and reduce repair times (see, generally, Exh. NG-CPIP-1, at 49-117). As noted above, the Department approves the ISRE mechanism to recover the capital costs for core capital spending. The Department finds that allowing both the ISRE mechanism and the Y factor would be inconsistent with the principle of efficient spending that a PBR plan is intended to encourage. The ISRE mechanism will allow the Company ample opportunity for recovery of capital investments, and the removal of the Y factor will incentivize the Company to diligently seek savings from its operational expenses. The annual PBR-O rate adjustments will provide additional year-to-year increases to O&M expense recovery during the PBR-O plan term.

Based on the foregoing considerations, and after a review of the evidence, we are not persuaded that the Y factor is a necessary addition to the proposed PBR-O mechanism to address the potential growth in O&M expenses (see, e.g., Exhs. NG-CPIP-1, at 17-18, 23, 159-160; NG-MM-NC-1, at 19-21; NG-LRK-1, at 15; NG-LRK-Rebuttal-1, at 29; AG-DED-1, at 15-19; AG-DED-3, Sch. 2; DPU 33-14; DPU 34-8; DPU 50-3; AG 4-48). Accordingly, the Department denies the Company's proposed Y factor.

vi. Earnings Sharing Mechanism

As noted, the Company proposes to implement an ESM that is asymmetric in nature and 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. NG-CPIP-1, at 31; NG-LRK-1, at 13-14;

proposed M.D.P.U. No. 1528, § 1.04). The Company proposes that for any year in which the ROE is above the deadband, 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. NG-CPIP-1, at 31-32; proposed M.D.P.U. No. 1528, § 1.04).

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

The Company developed the proposed ESM in alignment with recent Department precedent (Exh. NG-CPIP-1, at 31-32). The Department has traditionally found that a PBR plan term of five years warrants an asymmetrical ESM with upside sharing with customers but no downside adjustments. D.P.U. 23-80/D.P.U. 23-81, at 50-51; 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. 23-80/D.P.U. 23-81, at 50-51; D.P.U. 22-22, at 70; D.P.U. 19-120, at 89; D.P.U. 18-150, at 71-72; D.P.U. 17-05, at 401; D.T.E. 05-27, at 405; D.T.E. 03-40, at 500; D.P.U. 96-50 (Phase I) at 326.

As noted, the Attorney General argues the proposed ESM is an ineffective consumer protection, as no Massachusetts utility to date has ever shared excess earnings (Attorney General Brief at 24). Thus, she recommends rejecting the ESM in favor of a higher consumer divided (Attorney General Brief at 24). MEDA argues that the parameters of the proposed earnings sharing (i.e., 75/25 percent) are too favorable to shareholders (MEDA Brief at 51; MEDA Reply Brief at 23-24). The Department acknowledges that an ESM has never provided upside sharing with Massachusetts ratepayers, but we find it important not to conflate a lack of upside sharing with a lack of consumer protection. The Department concludes that the ESM offers customer protection in the event of increases in revenue outpacing increases in expenses. Further, we find no compelling reason not to include in the Company's PBR-O mechanism an asymmetrical ESM with the earnings sharing parameters proposed in this case. Additionally, as explained above, the Department has modified the proposed consumer dividend from 30 basis points to 40 basis points, which should address some of the Attorney General's concerns. We decline, however, to completely reject the ESM, as a disallowance of any earnings above the allowed ROE would suppress the efficiency incentives of the PBR-O plan. Rather, we conclude that a reasonable allowance of additional earnings provides the Company with ample reason to continuously seek out ways to increase operational efficiency, while protecting customers from excessive overearning. As noted above, the Department has routinely found a deadband of 100 basis points to be appropriate. For these reasons, the Department approves the Company's ESM as proposed. The approved asymmetrical ESM will have no downside adjustment and will include 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.

vii. Exogenous Cost Factor – Z factor

As noted above, National Grid proposes to include in the PBR-O adjustment formula an exogenous cost provision, or Z factor, which is defined as positive or negative changes to operating costs that, among other things, are beyond the Company's control and not reflected in the O&M composite inflation index or other elements of the PBR adjustment formula (Exhs. NG-CPIP-1, at 27-28; NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1). The Company proposes the significance threshold for exogenous costs to be set for the rate year at $3.6 million and for the threshold to be adjusted annually by the change in GDP-PI (Exhs. NG-CPIP-1, at 28; NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1).

In D.P.U. 94-158, at 62, the Department recognized that there may be exogenous costs, both positive and negative, that are beyond the control of a company and, where the company was subject to a stay-out provision, these costs may be appropriate to recover (or return) through the PBR mechanism. The Department has defined exogenous costs as positive or negative cost changes that are beyond a company's control and are not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 96-50 (Phase I) at 61-62. The Company proposed a definition of exogenous costs that is consistent with the definition established by the Department in D.P.U. 94-50 (Exhs. NG-CPIP-1, at 27-28;

NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1). Accordingly, the Department finds that the Company's proposed definition of exogenous costs in this instance is appropriate.

As noted above, the Company proposed an exogenous cost significance threshold of $3.6 million for each individual event for the first PBR-O plan year ending September 30, 2025, subject to annual adjustments thereafter based on changes in GDP-PI (Exhs. NG-CPIP-1, at 28; NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1). 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. 23-80/D.P.U. 23-81, at 53; D.P.U. 22-22, at 73; D.P.U. 20-120, at 97; D.P.U. 19-120, at 93-94; D.P.U. 18-150, at 66-67; D.P.U. 17-05, at 397; D.T.E. 03-40, at 491; D.T.E. 01-56, at 22-46; D.P.U. 96-50 (Phase I) at 293. Consistent with our precedent and facts of this case, the Department finds that $3.6 million is a reasonable exogenous cost significance threshold for the Company, which had total operating revenues of $2,847,886,522 in calendar year 2023 and is implementing a multi-year PBR-O plan with the overall design approved herein (Exhs. NG-CPIP-1, at 28; NG-LRK-1, at 14; proposed M.D.P.U. No. 1528, § 1.05.1).

In addition, the Company proposes 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 (Exhs. NG-CPIP-1, at 28; NG-LRK-1, at 14). 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-O plan term. D.P.U. 23-80/D.P.U. 23-81, at 53-54; D.P.U. 22-22, at 74; D.P.U. 19-120, at 94; D.P.U. 18-150, at 67; D.P.U. 17-05, at 398; D.T.E. 01-56, at 11-14;

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 $3.6 million, for each individual event in the first PBR-O plan year, ending October 1, 2026, subject to annual adjustments thereafter based on changes in GDP-PI as used in the PBR-O mechanism.

As noted above, National Grid proposes that individual storm events with O&M expense exceeding $30 million may be recovered through the Z factor in the PBR-O mechanism, pending a prudence review, provided that the combined balance of the Company's storm fund and any costs over $30 million associated with such storm event exceed $75 million (Exh. NG-CPIP-1, at 29; proposed M.D.P.U. No. 1528, § 1.05.2). As discussed in further detail in Section X.D.3. below, the Department approves this aspect of the Company's proposal.

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

5. Conclusion

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

In addition, we conclude that the PBR-O 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 is convinced that the PBR-O plan, as approved, satisfies our public policy goals and statutory obligations, including promotion of a safe and reliable electric distribution system, as well as the Commonwealth's clean energy mandates and goals.

With the modifications required herein, the Department finds that the PBR-O 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 the PBR-O plan, subject to the modifications above. The Company, in its compliance filing, shall submit a revised PBR-O plan tariff consistent with the findings in this Order.

Further, the Company shall submit annual PBR-O adjustment filings, including all information and supporting schedules necessary for the Department to review the proposed PBR-O adjustments for the subsequent rate year. Such information shall include the results and supporting calculations of the PBR-O adjustment factor formula, descriptions and accountings 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 impacts of applying the base distribution rate changes provided in the PBR-O adjustment filing.

National Grid proposes to submit its annual PBR-O adjustment filings on or before June 15, for rates effective October 1 (Exhs. NG-CPIP-1, at 18, 32; 156 NG-LRK-1, at 16). The Department has previously determined that a minimum of three months is needed to provide the Department and intervenors an opportunity to determine the appropriateness of PBR plan filings. Eversource Gas Company of Massachusetts, D.P.U. 22-122, at 11 n.6 (2022); NSTAR Gas Company, D.P.U. 22-121, at 16 n.14 (2022). Thus, we accept National Grid's proposal and direct the Company to submit its annual PBR adjustment filings on or before June 15 of each year, commencing in 2025 and continuing for the five-year term of the PBR-O plan. Consistent with our findings above, the PBR-O plan shall continue in effect for a total of five consecutive years starting October 1, 2024, with the last adjustment taking effect on October 1, 2029, subject to the findings set forth above.

D. Service Quality Proposal

1. Introduction

The current SQ Guidelines applicable to all EDCs define "sustained interruption" as an interruption of electric service that lasts at least one minute. Service Quality Guidelines, D.P.U. 12-120-D, Att. A at 5, 6 (2015). The EDCs annually track, calculate, and report on the duration of customer interruptions through various indices and measures, including the SAIDI, SAIFI, Circuit Average Interruption Duration Index ("CKAIDI"), Circuit Average Interruption Frequency Index ("CKAIFI"), Customers Experiencing Long Interruption Duration ("CELID"), and Customers Experiencing Multiple Interruptions ("CEMI"). Momentary interruptions (i.e., interruptions lasting less than one minute) are excluded from the calculation of SAIDI, SAIFI, CKAIDI, CKAIFI, CELID, and CEMI. D.P.U. 12-120-D, Att. A at 12. The EDCs are subject to penalties if their performance in restoring service interruptions falls below a company-specific benchmark. D.P.U. 12-120-D, Att. A at 14-16.

National Grid states that, as part of its Grid Modernization program, it continues to deploy its FLISR technology on its distribution circuits to improve reliability (Exh. NG-CPIP-1, at 126). According to the Company, FLISR devices are part of the advanced distribution automation control scheme that incorporates telecommunication and advanced control of key switching devices (Exh. NG-CPIP-1, at 135). FLISR significantly increases reliability, and therefore enhances customer experience, because it automatically and quickly restores service to large numbers of customers (Exh. NG-CPIP-1, at 126, 135). For example, the Company states that historically it took a field worker 45 minutes or longer to physically respond, locate, isolate, and partially restore customers, but FLISR technology automatically identifies and isolates faulted feeder sections and restores power to the remaining customers typically in less than one minute (Exh. NG-CPIP-1, at 126; NG-PIMS-Rebuttal-1, at 16).

The Company states, however, that the complexity of FLISR "schemes"[28] is increasing as the grid becomes more dynamic, and there are instances where FLISR will not "self-heal" in under the one-minute sustained interruption threshold (Exh. NG-CPIP-1, at 126). For example, the Company notes that the number of sectionalizing points and tie points can influence how quickly FLISR can complete restoration after an event (Exh. NG-CPIP-1, at 126). Further, increased amounts of distributed energy resources ("DER") on a circuit can create a masked load,[29] which can influence how quickly FLISR can complete a restoration event (Exh. NG-CPIP-1, at 126).

National Grid states that without a change to the SQ Guidelines' definition of sustained interruption, outages restored by FLISR that previously were not considered sustained interruptions will be counted as such, thereby adversely impacting the Company's reliability metrics, even though customers are receiving better service quality (Exh. NG-CPIP-1, at 127-128). Thus, National Grid proposes a temporary modification of the definition of sustained interruption in the current SQ Guidelines, applicable to all EDCs, to increase the minimum time threshold for triggering duration of the interruption from one minute to five minutes (Exh. NG-CPIP-1, at 122, 128-129). The Company states that the requested

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28 A FLISR scheme includes the design and installation of multiple grid automation devices such as pole-top reclosers, feeder monitoring devices, and other devices to enable a coordinated and automated response to system contingencies and grid monitoring (Exh. NG-CPIP-1, at 136).

29 A masked load refers to a situation where output from one or more DER connected to a distribution feeder offsets the demand of load customers on the same feeder, making the load on the feeder, or feeder section, appear to be lower than it is (Exh. NG-CPIP-1, at 126 n.11).

modification will allow improvements delivered to customers through the recent deployment of FLISR technology to be reflected in the Department's regulatory reliability measures (Exh. NG-CPIP-1, at 122). The Company requests that the proposed modification continue until a permanent decision on the definition of sustained interruption can be made when the Department next reviews the SQ Guidelines (Exh. NG-CPIP-1, at 128).

2. Positions of the Parties

a. Attorney General and DOER

The Attorney General and DOER do not specifically address the Company's proposal on brief. They note, however, that the Department has opened an investigation into SQ standards, docketed as Revised Service Quality Guidelines, D.P.U. 24-53, and that SQ standards should be determined as a part of that investigation, rather than in the instant base distribution rate case (Attorney General Brief at 33; DOER Brief at 55).

b. Company

National Grid reiterates its proposal on brief (Company Brief at 94-99). The Company argues that it is imperative that the associated reliability improvements delivered to customers with FLISR technology are reflected in Company's reliability metrics (Company Brief at 94, 96-97). Further, the Company asserts that the Department approved a temporary modification of the SQ Guidelines' definition of "excludable major event" in D.P.U. 22-22 that applied to all EDCs (Company Brief at 99).

3. Analysis and Findings

In D.P.U. 22-22, at 327, the Department noted that it would open a proceeding to evaluate the current SQ Guidelines, at which time all EDCs and relevant stakeholders would have an opportunity to comment on proposed refinements to the SQ Guidelines. At the time of the Company's filing in the instant case in November 2023, the new SQ Guidelines proceeding was not yet opened. The Department opened the proceeding on May 21, 2024, and docketed the matter as D.P.U. 24-53. The proceeding remains pending.

The Company's proposal in the instant case would change the regulatory definition of sustained interruption that the Department has used in its SQ standards since their inception in Service Quality Standards, D.T.E. 99-84 (2001). Given the potential ramifications of this proposal, the Department finds that it is better suited for examination in D.P.U. 24-53 should the Company wish to raise it in that proceeding. In that proceeding, all EDCs and relevant stakeholders will have an opportunity to comment on any potential changes to the SQ Guidelines, and the Department can conduct a full investigation of the impact of any changes. As that proceeding is now underway with comments due this fall, we are not persuaded that a temporary change to the definition of sustained interruption is necessary. D.P.U. 24-53, Joint Motion for Extension of Time (Stamp Approval July 17, 2024). Accordingly, we reject the Company's proposal.

E. Incurred Debt Recovery Factor

1. Company Proposal

As part of its CPI plan, the Company proposes to include an IDRF to address significant interest rates changes, in either direction, during the plan's five-year term (Exhs. NG-CPIP-1, at 30-31; NG-AEB-1, at 76; proposed M.D.P.U. No. 1528, § 1.05.4). The IDRF would be triggered based on the difference between the allowed debt expense and the actual incurred debt expense as compared to the Company's proposed exogenous cost significance threshold (adjusted annually for inflation) of $3.6 million (Exhs. NG-CPIP-1, at 30; NG-AEB-1, at 77; proposed M.D.P.U. No. 1528, § 1.05.4). Under National Grid's proposal, the allowed debt expense would be calculated as: (1) the product of the Company's average rate base for the PBR year; (2) the capital structure debt ratio allowed for ratemaking purposes in this proceeding; and (3) the weighted average cost of debt allowed in this proceeding (Exh. NG-CPIP-1, at 30). The calculation of actual debt expense would be the same, except that the weighted average cost of debt would be updated to reflect any new debt issued by the Company during the PBR plan (Exhs. NG-CPIP-1, at 30-31; proposed M.D.P.U. No. 1528, § 1.05.4).

National Grid proposes that, if actual debt expense exceeds the Company's allowed debt expense by more than the significance threshold, the Company may file for recovery of the additional expense in the subsequent PBR year (Exhs. NG-CPIP-1, at 30-31; NG-AEB-1, at 77-78; proposed M.D.P.U. No. 1528, § 1.05.4). Conversely, if actual debt expense is lower than the Company's allowed debt expense by more than the same threshold amount, National Grid would file to return the excess revenue to customers (Exh. NG-AEB-1, at 78; proposed M.D.P.U. No. 1528, § 1.05.4).

2. <u>Positions of the Parties</u>

a. <u>Attorney General</u>

The Attorney General asserts that the Department should deny the Company's IDRF proposal (Attorney General Brief at 20-21). In particular, the Attorney General argues that the proposed IDRF is unnecessary, as the Company was able to secure favorable interest rates on its long-term debt financing for its capital investments without an IDRF; specifically, a half-billion dollars in debt financing at a 1.73 percent interest rate issued in 2020 (Attorney General Brief at 21, citing Exh. AG-DED-1, at 20). The Attorney General also rejects the Company's characterization of interest rates as being volatile for the foreseeable future (Attorney General Brief at 21; Attorney General Reply Brief at 6-7). According to the Attorney General, interest rates, like energy commodity prices, are not expected to drastically fluctuate over the next few years (Attorney General Brief at 21, citing Exh. AG-DED-1, at 20). Further, the Attorney General contends that the IDRF shifts financial risk away from the Company and onto ratepayers in a way that is neither efficient nor equitable and is "bad public policy" since the Company is in a better place to mitigate such risks relative to ratepayers (Attorney General Brief at 20-21; Attorney General Reply Brief at 6).

b. Company

National Grid argues that the IDRF is an important guardrail against significant over- or under-recovery of actual interest expense, especially since the Company will need to issue a significant amount of debt to support its capital investment plans over the next five years and the cost of that debt will be determined by market-based interest rate levels at the time of issuance, which are outside the Company's control (Company Brief at 166-168, 255, citing Exhs. NG--CPIP-Rebuttal-1, at 18; DPU 1-10; Company Reply Brief at 30). National Grid contends that current interest rates on long-term debt are higher than the Company's weighted average cost of debt, and in recent years such interest rates have been volatile and unpredictable (Company Brief at 168, 255-256, citing Exhs. NG-AEB-1, at 78; DPU 1-15). The Company also notes that its proposed weighted average cost of debt is based on historical debt issuances (as updated for debt issuances during this proceeding) and does not reflect current or projected interest rates (Company Brief at 171, citing Exh. DPU 1-14). Further, the Company claims that the possibility of under-recovering a significant amount of new debt expense over the five-year rate plan would have adverse cash flow implications and may be viewed negatively by the credit rating agencies in the current market environment (Company Brief at 169, citing Exh. DPU 1-15).

The Company argues that its proposal is consistent with the requirements of the proposed exogenous cost factor under the proposed PBR mechanism, it will provide transparency regarding debt cost increases or decreases, and it will allow for fair and timely recovery of actual debt expense (Company Brief at 169-171, citing Exhs. NG-AEB-1, at 19-22; DPU 1-11). Further, the Company rejects the notion that the proposed IDRF will shift risk to ratepayers (Company Reply Brief at 30). According to National Grid, the IDRF protects customers from paying higher debt costs than the Company incurs, which otherwise might happen due to the unpredictability of interest rates (Company Reply Brief at 30, citing Exh. NG-AEB-Rebuttal-1, at 102-103).

3. Analysis and Findings

The Department has given careful consideration to the Company's IDRF proposal. As an initial matter, we note that no other Massachusetts utility has a similar mechanism to recover the difference between allowed and actual debt expenses. While we acknowledge that interest rates have a degree of unpredictability, the record shows that the Company was able to achieve lower interest rates than anticipated in the issuance of $400 million of long-term debt in February 2024, with a final interest rate of 5.87 percent[30] rather than the anticipated 6.63 percent – a 76-basis

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[30] The Department acknowledges that the Company also was able to secure $500 million in debt financing in 2020 at an interest rate of 1.73 percent (Exhs. NG-CPIP-1, at 30;

point decrease (Exh. NG-AEB-Rebuttal-1, at 13). With respect to future debt, underwriters already factor in potential inflation and future interest rates in the pricing of long-term debt securities (Exh. DPU 1-13). Further, the Department finds that the Company has existing recovery mechanisms to address a certain level of debt expenses, and it has proposed additional relevant recovery mechanisms during this proceeding (Exh. DPU 15-7; Tr. 4, at 540-541, 543, 550-552). The Department also finds that, to a certain degree, it is within the Company's management's control to determine when to issue debt (Exh. DPU 1-12). As such, if management expects to issue a significant amount of debt but has concerns regarding volatile and elevated interest rates in the future, the Company may choose to issue debt earlier. The IDRF, on the other hand, diminishes the Company's incentive to issue debt when rates are more favorable. Although the Company notes that the IDRF will account for any over-recoveries of actual debt costs (Company Reply Brief at 30, citing Exh. NG-AEB-Rebuttal-1, at 102-103), we are not persuaded that the proposal offers sufficient customer benefits to warrant its approval. Moreover, we are not persuaded that the proposed IDRF is necessary for the Company to fulfill its obligations to provide safe and reliable electric service, while making progress towards achieving the Commonwealth's energy goals and climate targets.

Based on the above considerations, the Department finds that, on balance, the Company's IDRF proposal is unnecessary and improperly shifts risk to ratepayers, and that the Company has alternative methods to manage actual debt costs. Accordingly, the Department rejects the

AG--JRW-Testimony-1, at 12-13). Given that interest rates were generally lower at the time, we consider the debt issued in 2024 to be more instructive to our analysis.

proposed IDRF. In its compliance filing, the Company shall remove the IDRF provision and associated references from its compliance tariffs.

F. Investment-Based Performance Incentive Mechanisms

1. Introduction

In this proceeding, National Grid proposes four IPIMs that the Company states are designed to hold it accountable to deliver results in relation to its core investments under the ISRE mechanism (Exh. NG-CPIP-1, at 129, 131; Tr. 5, at 643, 676). National Grid states that each IPIM is designed to be symmetrical, such that it penalizes the Company if it fails to deliver results above a target range and rewards the Company for exceptional performance (Exh. NG-CPIP-1, at 130-131).

The Company also states that the proposed IPIMs are conditioned on approval of sufficient recovery under the proposed ISRE mechanism, including the associated investment cap, and the proposed PBR-O mechanism (Exh. NG-CPIP-1, at 132, 134). National Grid notes that if the investment cap level is modified or is not approved, the Company would need to assess whether it could sustain the IPIM proposals or modify or withdraw them (Exh. NG-CPIP-1, at 132, 134). According to National Grid, without funding and recovery commensurate with the work that needs to be completed, the Company will be unable to realistically meet what it considers to be aggressive proposed IPIM targets (Exh. NG-CPIP-1, at 132).

The four proposed IPIMs are: (1) a FLISR deployment metric; (2) an underground residential development ("URD") direct buried cable replacement metric, related to the

Company's URD replacement program; (3) an overhead hardening for resiliency metric; and (4) an SQ metrics extension (Exh. NG-CPIP-1, at 135). Each proposed IPIM is discussed below.

2. Company Proposal

a. FLISR Deployment IPIM

As discussed above, FLISR devices are part of the advanced distribution automation control scheme that incorporates telecommunication and advanced control of key switching devices (Exh. NG-CPIP-1, at 135). The Company states that its FLISR technology significantly increases reliability, and therefore enhances customer experience, because it automatically and quickly restores service to large numbers of customers (Exhs. NG-CPIP-1, at 126, 135; NG-PIMS-Rebuttal-1, at 16; Tr. 5, at 635, 680; Tr. 6, at 796). During the five-year CPI Plan, the Company aims to cover 80 percent of its FLISR-eligible 15 kilovolt ("kV") feeders in Massachusetts, which results in an annual target of enabling FLISR on 60 feeders (Exhs. NG-CPIP-1, at 136; NG-PIMS-Rebuttal-1, at 17-18). To measure the performance of this proposed IPIM, the Company would report the number of new FLISR-enabled feeders deployed over the twelve months of each calendar year (Exhs. NG-CPIP-1, at 136; NG-PIMS-Rebuttal-1, at 18).

The Company proposes a symmetrical deadband of 20 percent of the targeted 60 feeders each year (Exhs. NG-CPIP-1, at 137; NG-PIMS-Rebuttal-1, at 17-18; DPU 49-3 & Att.). For each additional FLISR-enabled feeder completed above 72 feeders, or 20 percent above the target, in calendar year 2025, the Company would earn an incentive of $183,333 until the maximum incentive cap of $3.3 million is reached (Exhs. NG-CPIP-1, at 137; DPU 49-3 & Att.). Symmetrically, if the Company installs FLISR capabilities on fewer than 48 feeders, or

20 percent below the target, in calendar year 2025, the Company will pay a penalty of $183,333 for each feeder below the deadband until the maximum penalty cap of $3.3 million is reached (Exhs. NG-CPIP-1, at 137; DPU 49-3 & Att.).[31] Under the Company's proposal, it can petition the Department to waive the penalty amount if it is unable to meet the targeted number of feeders due to permitting delays (Exh. NG-CPIP-1, at 138; NG-PIMS-Rebuttal-1, at 17-18). The Company will bear the burden to demonstrate that the permitting delays were beyond its control (Exh. NG-CPIP-1, at 138).

b. URD Direct Buried Cable Replacement IPIM

The Company states that direct buried cable was heavily used during the housing boom of the 1970s and 1980 and, with age, the cables are failing more frequently (Exhs. NG-CPIP-1, at 139-140; NG-PIMS-Rebuttal-1, at 24; Tr. 6, at 814-817). National Grid's proposed IPIM would measure the Company's improvement of service reliability to those customers experiencing four or more outages over the prior three years due to failure of their direct buried primary cable (Exhs. NG-CPIP-1, at 139-143; NG-PIMS-Rebuttal-1, at 24; Tr. 6, at 795-796).

The Company explains that when a direct buried cable fault occurs, the cable's fused protective device operates, i.e., opens, to avoid interrupting a larger number of customers (Exhs. NG-CPIP-1, at 140; DPU 40-1). National Grid can track outages based on the number of times the fused protective device operates, and the Company proposes that at the start of each

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31 The Company proposes that the amount of incentive or penalty per feeder, as well as the maximum incentive or penalty, increase in each successive calendar year through the CPI Plan term, as follows: (1) 2026 - $200,000/$3.6 million; (2) 2027 - $211,111/$3.8 million; (3) 2028 - $233,333/$4.2 million; and (4) 2029 - $250,000/$4.5 million (Exhs. NG-CPIP-1, at 139; DPU 49-3, Att.).

calendar year, it will compile a list of fused protective devices that operated four or more times over the prior three years because of a direct buried cable fault (Exhs. NG-CPIP-1, at 140-141; NG-PIMS-Rebuttal-1, at 25). Based on historical performance over the past three years, the Company proposes as a target that 70 percent or more of these fuses will not operate during the year from direct buried cable faults (Exhs. NG-CPIP-1, at 141; NG-PIMS-Rebuttal-1, at 25). To reach the 70 percent target pass rate, National Grid would track operations of protective fuse devices that result from failed direct buried underground cables and prioritize the replacement of sections that experience repeated failures with cable in conduit, which the Company states have an expected life span of 50 years (Exhs. NG-CPIP-1, at 140-141; NG-PIMS-Rebuttal-1, at 25).

The Company proposes a symmetrical deadband of 10 percent over or under the target pass rate of 70 percent for the URD direct buried cable IPIM (Exhs. NG-CPIP-1, at 142; NG-CPIP-7, at 4). Thus, the Company would earn an incentive only if its performance exceeds an 80 percent pass rate and will pay a penalty if its performance is below a 60 percent pass rate (Exhs. NG-CPIP-1, at 142; NG-CPIP-7, at 4; Tr. 6, at 818). The Company proposes for calendar year 2025, an incentive or penalty of $35,000 per percentage point above or below the deadband (Exhs. NG-CPIP-1, at 143-144; NG-CPIP-7, at 4).[32]

[32] The Company proposes that the amount of incentive or penalty per percentage point, as well as the maximum incentive or penalty, increase in each successive calendar year in proportion to the projected capital spend each year of the CPI Plan, as follows: (1) 2026 - $40,000/$800,000; (2) 2027 - $50,000/$1.0 million; (3) 2028 - $60,000/$1.2 million; and (4) 2029 - $75,000/$1.5 million (Exhs. NG-CPIP-1, at 144; NG-CPIP-7, at 4).

c. Overhead Hardening for Resiliency IPIM

The Company proposes an overhead hardening for resiliency IPIM designed to improve the resilience of the distribution grid by replacing targeted mainline overhead wire with tree-resistant wire (Exh. NG-CPIP-1, at 145-146; Tr. 6, at 795-797). The Company's focus of this proposed IPIM is vulnerable mainline sections of overhead wire based on their underperformance during major events and climate projection data, where available (Exh. NG-CPIP-1, at 146; Tr. 6, at 819-820). National Grid proposes to track and report on the number of miles where targeted overhead wire is replaced with tree-resistant wire (Exh. NG-CPIP-1, at 146). National Grid anticipates the work will begin in fiscal year 2026, which it states will give the Company time to launch the program through identification and design, with a target to deliver 50 miles by the end of the five-year rate plan (Exh. NG-CPIP-1, at 146).[33]

National Grid proposes a symmetrical deadband of ten miles over or under the target replacement rate of 50 miles over the five years, such that the Company will earn an incentive only if it hardens more than 60 miles within the five years, and the Company will pay a penalty if it does not harden a minimum of 40 miles at the end of the program period (Exh. NG-CPIP-1, at 147; Tr. 6, at 820). The Company proposes an incentive or penalty of $500,000 per mile

[33] The Company notes, however, that because it has not previously managed and deployed this program, meeting a target of 50 miles is conditioned on system capacity and performance budget in the five-year capital plan for core investments, and if this budget is decreased, the target miles also would need to be decreased (Exh. NG-CPIP-1, at 147).

above or below the deadband, with a maximum incentive or penalty of $10.0 million (Exhs. NG-CPIP-1, at 147-149; NG-CPIP-7, at 5).[34]

The Company proposes to evaluate the IPIM at the end of the five-year CPI Plan, rather than annually, because the program is new (Exh. NG-CPIP-1, at 147). Further, the Company proposes to report annually on the number of overhead miles hardened, but it will not establish specific annual targets (Exh. NG-CPIP-1, at 147).

d. Service Quality Extension Metric IPIM

In D.P.U. 12-120-D at 18-20, the Department established new average performance levels for all EDCs and created a "glide path" of reductions in the minimum performance levels for SAIDI and SAIFI.[35] Under the guidelines, every three years the threshold for incurring penalties in each of these metrics would step down by one-sixth of a standard deviation of the historical average performance (Exh. NG-CPIP-1, at 150). D.P.U. 12-120-D at 18-19. The fourth and final step down in the glide path is scheduled to occur in 2025 (Exh. NG-CPIP-1, at 150). See D.P.U. 12-120-D at 18-19. At that time, the Company's SAIDI and SAIFI minimum performance levels will be 134.152 minutes for SAIDI and 1.343 interruptions SAIFI (Exh. NG-CPIP-1, at 151).

In the instant proceeding, the Company proposes to further reduce acceptable reliability to 127.542 minutes for SAIDI and 1.314 interruptions for SAIFI (Exhs. NG-CPIP-1, at 150-151;

34 The Company also proposes that the budget for the overhead hardening program be limited to a maximum cap of $121.8 million to deliver the target of 50 miles of overhead hardening over five years (Exhs. NG-CPIP-1, at 149; AG 6-6; Tr. 6, at 821).

35 A glide path is a benchmarking method with increasing stringency over a fixed number of years. D.P.U. 12-120-D, Att. A at 4.

NG-CPIP-7, at 6). National Grid proposes that these enhanced performance levels become effective in 2028, following the three-year step-down schedule of the original glide path; the Company states that it will need the additional three years to understand the impacts of the CPI Plan on improved reliability (Exh. NG-CPIP-1, at 150).

In addition to extending the glide path to incur penalties outlined in the SQ Guidelines, National Grid proposes an incentive for achieving outperformance on SAIDI as a means of driving creativity and dynamic efficiencies to deliver the Company's core investments through the CPI Plan and realize significantly improved service levels for customers (Exh. NG-CPIP-1, at 151). The incentive would apply only for the last two years of the five-year rate plan, with the level of performance for SAIDI to earn an incentive starting at one-third standard deviation from the average performance established in D.P.U. 12-120-D (Exh. NG-CPIP-1, at 151). National Grid proposes that the value of the incentive would be up to 0.688 percent of the Company's transmission and distribution revenues, which amount to approximately $10 million at current levels, symmetrical with the potential penalty, spread over a full standard deviation of performance, as established in the SQ Guidelines (Exhs. NG-CPIP-1, at 151, 153; NG-CPIP-7, at 6). The Company proposes that any incentive earned would be recovered through the proposed ISRE mechanism, while any penalty for underperformance would still be reported and evaluated through the existing annual SQ filings (Exh. NG-CPIP-1, at 153).[36]

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[36] The Company stated that potential penalties could be reevaluated during the future SQ proceedings (Exh. DPU 29-4).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's proposed FLISR deployment IPIM, URD direct buried cable replacement IPIM, and the overhead hardening for resiliency IPIM are inappropriate and should be rejected (Attorney General Brief at 25). The Attorney General outlines two threshold principles and six design guidelines that she asserts must be met (Attorney General Brief at 26). The Attorney General contends that each IPIM is related to reliable service, which is a core aspect of the Company's public service obligation and, as such, each IPIM fails the Department's threshold test for approval (Attorney General Brief at 26-27, 29, 30-31). Further, the Attorney General claims that the Company failed to perform a cost-benefit analysis for each IPIM and, as such, each IPIM fails to satisfy the Department's second design guideline (Attorney General Brief at 27, 29, 31; Attorney General Reply Brief at 10). Additionally, the Attorney General maintains that each IPIM creates a perverse incentive for the Company by encouraging more installations regardless of cost effectiveness, thereby violating the Department's fifth design guideline (Attorney General Brief at 27-28, 29-30, 31-32; Attorney General Reply Brief at 9). Finally, the Attorney General asserts that because achieving the proposed IPIM's objectives depends on capital spending, the Company receives a duplicate reward of both the IPIM incentive and expanding rate base generally, in violation of the Department's sixth design guideline (Attorney General Brief at 28, 30, 32 Attorney General Reply Brief at 9-10).

Regarding the SQ extension metric IPIM, the Attorney General argues that continuation or alteration of minimum performance levels should be determined as a part of the investigation in D.P.U. 24-53 and not adjudicated in the instant proceeding (Attorney General Brief at 33). Further, the Attorney General contends that the proposed SQ extension metric IPIM should be rejected because it is insufficiently challenging given the significant reliability investments National Grid plans to undertake and in light of the Company's already relatively positive SAIDI and SAIFI performance (Attorney General Brief at 33).

b. DOER

DOER argues that the Department should reject the Company's IPIMs and direct the Company to address performance metrics comprehensively in a separate phase of the ESMP proceedings (DOER Brief at 2, 50-53; DOER Reply Brief at 6). DOER also contends that each of National Grid's proposed IPIMs concern activities that are within the Company's public service obligation to deliver reliable service, provide increased service reliability, or reduced outages (DOER Brief at 54, citing Exh. NG-CPIP-1, at 135, 140, 146, 152). Thus, DOER claims that there is no justification for encouraging the Company through additional financial incentives to prevent outages because it is within its service obligation as a utility to ensure customers have access to reliable energy services (DOER Brief at 54). DOER also asserts that the Department should reject the Company's SQ extension metric IPIM and address SQ changes consistently for all EDCs in D.P.U. 24-53 (DOER Brief at 55).

c. CLF, EDF, and Acadia Center

CLF, EDF, and Acadia Center argue that each of the proposed IPIMs fails to meet the Department's threshold for approval because the reliability it would create constitutes an ongoing Company public service obligation and each IPIM duplicates an existing financial incentive for which the Company is compensated already (CLF Brief at 17-19; EDF Brief at 11-12; Acadia Center Brief at 17; CLF, EDF, and Acadia Center Reply Brief at 5-6). Further, EDF and Acadia Center claim that the FLISR deployment IPIM and the URD direct buried cable replacement IPIM are not ambitious enough, given that the Company already has achieved its target performance in recent years (EDF Brief at 17-18; Acadia Center Brief at 14). Additionally, CLF and EDF maintain that the current enforcement of SAIDI performance standards occurs through a penalty-only structure that the Department has upheld while shifting performance targets from preventing deterioration to requiring improvements (CLF Brief at 19; EDF Brief at 15-16). CLF asserts that the Company's proposed SQ metrics extension IPIM contradicts the Department's strategy of enforcing SAIDI performance standards, and EDF maintains that allowing this IPIM may cause complications concerning how to distribute rewards and penalties if the Department issued another set of systemwide SQ guidelines in a subsequent docket that applied to all EDCs (CLF Brief at 19; EDF Brief at 16).

CLF, EDF, and Acadia Center recommend that the Department direct National Grid to propose and implement a single reliability IPIM that improves reliability in: (1) vulnerable communities with environmental justice populations experiencing worse than average reliability; and (2) the Company's worst performing feeders, specifically prioritizing communities with environmental justice populations (CLF Brief at 22-23; EDF Brief at 17-18; Acadia Center Brief at 19).

d. Company

National Grid argues that the proposed IPIMs are linked to the ISRE Mechanism and will penalize or reward the Company based on the effectiveness of its delivery of its core investments relative to a target range and upper and lower deadbands (Company Brief at 181). National Grid contends the proposed IPIMs will provide assurance, transparency, and accountability that the Company is delivering its core capital improvements under the CPI Plan in a timely and reliable manner (Company Brief at 181). In particular, the Company maintains that the IPIMs do not encourage spending regardless of cost effectiveness, but rather they provide accountability for capital spending (Company Reply Brief at 37). The Company asserts that its IPIMs should be approved as an integral component of the overall CPI Plan (Company Brief at 236).

The Company rejects the Attorney General's arguments regarding the lack of cost-benefit analyses to support the proposed IPIMs (Company Reply Brief at 38). National Gird maintains that no such analysis is required in Massachusetts; it is difficult to calculate a cost-benefit analysis for the overhead hardening IPIM, as benefits are hard to fully quantify in the short term because resilience improvements are, in part, based on climate change, which has a long-term effect; and the Company did, in fact, provide a cost-benefit analysis of FLISR during the proceeding (Company Reply Brief at 38, citing Exh. DPU 22-8). National Grid also contends that the Attorney General's argument that the proposed SQ extension metric is too lenient is misplaced, as the Company proposes to reduce the minimum performance levels for SAIDI and SAIFI below the glide path levels, thus making it more difficult to achieve acceptable performance without incurring penalties (Company Reply Brief at 39). Further, National Grid dismisses any concerns about the proposed IPIMs duplicating an additional financial incentive, as suggested by several intervenors, and argues that the IPIMs are symmetrical, so that the Company also faces penalties for deficient performance (Company Reply Brief at 38).

Regarding the IPIM proposed by CLF, EDF, and Acadia Center, the Company argues that it has demonstrated in this proceeding that environmental justice populations typically fall within the upper half of reliability performance (Company Brief at 234, citing Exhs. NG-PIMS-Rebuttal-1, at 77-79; EDF-CLF 2-30). Further, the Company contends that it will not have sufficiently accurate customer-level reliability to implement the intervenors' proposed IPIM until AMI is fully deployed (Company Brief at 234, citing Exh. NG-PIMS-Rebuttal-1, at 78-79).

4. Analysis and Findings

a. Introduction

As noted above, the Company states that its proposed IPIMs are conditioned on approval of sufficient recovery under the proposed ISRE mechanism, including the associated investment cap, and the proposed PBR-O mechanism (Exh. NG-CPIP-1, at 132, 134). In Section IV.B.3. above, we rejected the Company's ISRE mechanism, as proposed, but we approved a capital tracker with a modified investment cap. In Section IV.C.4. above, the Department approved the Company's PBR-O mechanism. In light of these decisions, we will address the Company's IPIMs, as proposed.

b. Review Criteria

The Department reviews PIMs based on the criteria established in D.P.U. 18-150. First, the Department must determine whether the PIM satisfies the threshold principles designed to weigh whether an action addressed in the PIM is appropriate to consider for performance incentives. D.P.U. 18-150, at 120. In making this determination, the Department has found that performance incentives can serve as a useful regulatory mechanism when used to positively influence distribution company behavior in the advancement of important public policy goals that are not directly aligned with a distribution company's public service obligations. Net

Metering, SMART Provision, and the Forward Capacity Market, D.P.U. 17-146-B at 15-16, 56-59 (2019); see also D.P.U. 94-158, at 54 (an incentive plan should improve on a company's performance that would have been offered under current regulation). Conversely, performance incentives are generally not appropriate where the affected activity is within the distribution company's public service obligations. D.T.E./D.P.U. 06-107-B at 55-60; see also Western Massachusetts Electric Company, D.T.E. 04-40/D.T.E. 04-109/D.T.E. 05-10, at 5-6 (2006) (type of expenditures recorded in ordinary course of business and recovered as part of company's test-year O&M expense should not be afforded special ratemaking treatment). The Department has found that to be considered on its design merits, a PIM first must be found to meet the threshold principles that: (1) it advances specific public policy goals; and (2) the affected activity is clearly outside a distribution company's public service obligations. D.P.U. 18-150, at 121.

Upon determining that a PIM meets these threshold principles, the Department must determine whether the proposed PIM meets appropriate design guidelines. The Department has determined that an appropriately designed incentive mechanism must: (1) be designed to encourage program performance that best achieves the Commonwealth's energy goals; (2) be designed to enable a comparison of (i) clearly defined goals and activities that can be sufficiently monitored, quantified, and verified after the fact, to (ii) the cost of achieving the target to the potential quantifiable benefits; (3) be available only for activities where the distribution company plays a distinct and clear role in bringing about the desired outcome; (4) be consistent across all EDCs and LDCs, where possible, with deviations across companies clearly justified; (5) be created to avoid perverse incentives; and (6) ensure that the distribution company is not rewarded for the same action through another mechanism. D.P.U. 18-150, at 121-122, citing Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 17-13, at 42-43, 46 (2018); Investigation into Updating Energy Efficiency Guidelines, D.P.U. 08-50-A at 49-50 (2009); D.P.U. 94-158, at 52-66. In addition, the Department may allow a modification to an approved incentive mechanism where justified. D.P.U. 08-50-A at 49-50.

c. FLISR Deployment IPIM

The installation of FLISR furthers the Commonwealth's goals of improving grid reliability, communication, and resiliency (Exh. AG 6-12; Tr. 5, at 635, 680; Tr. 6, at 796). The Company estimates that FLISR improves both SAIDI and SAIFI by 21 percent at the feeder where the technology is deployed (Exh. AG 6-3 & Att. (Rev.)). We find that improving reliability is an activity that is clearly within the Company's public service obligation to provide safe and reliable service to customers. Thus, we conclude that the proposed FLISR deployment IPIM does not satisfy the Department's first threshold principle. While our inquiry could end here, we also are persuaded that the Company's proposal is inconsistent with our design guideline that the distribution company is not rewarded for the same action through another mechanism. National Grid expects to spend more than $40 million annually for FLISR deployments and would recover prudently incurred costs through an approved capital tracker, including an authorized return (Exhs. NG-CPIP-1, at 93-94; DPU 22-6).[37] While we recognize that this proposal may provide accountability and transparency in deploying FLISR, and there is

[37] The majority of the Company's 2025 FLISR costs will be recovered through its Grid Modernization Factor, up to the preauthorized budget of $37.7 million plus a 15 percent variance approved for the 2022 to 2025 Grid Modernization Plan term (Exh. DPU 22-6).

a penalty component to the IPIM, the proposal is designed to provide an incentive for which the Company already will be rewarded through accelerated cost recovery in the ratemaking process (Exhs. NG-CPIP-1, at 137; NG-PIMS-Rebuttal-1, at 21). We also find that the IPIM's design creates a perverse incentive, in violation of our design guidelines, as it encourages spending on FLISR deployments regardless of the outcome deployment would have for customers (Exh. AG-WG-1, at 31). In particular, the Department is concerned the IPIM, as designed, could incentivize non-cost-efficient FLISR deployments, as FLISR costs and benefits vary widely depending on the scheme (Exhs. AG-WG-1, at 32; AG 6-3 (Rev.)). Based on these considerations, the Department rejects the Company's FLISR deployment IPIM.

d. URD Direct Buried Cable Replacement IPIM

National Grid's URD direct buried cable replacement IPIM is designed to improve customer reliability, as it measures the Company's improvement of service reliability to those customers experiencing four or more outages over the prior three years due to failure of their direct buried primary cable (Exhs. NG-CPIP-1, at 139-143; NG-PIMS-Rebuttal-1, at 24; Tr. 6, at 795-796, 814-817). As such, similar to our findings above, we conclude that this proposal does not meet the Department's first threshold principle. Additionally, the Company plans to spend over $36 million on replacing direct buried cable with cable in conduit under the URD program and to recover prudently incurred costs through the approved capital tracker, including an authorized return (Exhs. NG-CPIP-1, at 84-85; AG 6-4 & Att.). Thus, similar to the FLISR deployment IPIM, we find that the URD direct buried cable replacement IPIM is designed to provide an incentive for which the Company already will be rewarded through accelerated cost recovery in the ratemaking process, in violation of our sixth design guideline. Based on these considerations, the Department rejects the Company's URD direct buried cable replacement IPIM.

e. Overhead Hardening for Resiliency IPIM

The Company's overhead hardening for resiliency IPIM also is focused on improving reliability through strengthening the resilience of the distribution grid by replacing targeted mainline overhead wire with tree-resistant wire (Exh. NG-CPIP-1, at 145-146; Tr. 6, at 795-797, 819-820). Thus, for the reasons discussed above, we find that this proposal fails to satisfy the Department's first threshold principle. The Company proposed a budget for the overhead hardening program to be capped at $121.8 million, based on a target of 50 miles of overhead hardening over five years (Exhs. NG-CPIP-1, at 149; AG 6-6; Tr. 6, at 821). During the proceeding, the Company provided a preliminary list of circuits that comprised approximately 43 miles of overhead hardening for the fiscal year 2025 to 2029 period, at a cost of approximately $79 million (Exh. AG 6-6 & Att.). The Company proposes to recover prudently incurred costs through the approved capital tracker, including an authorized return (Exhs. NG-CPIP-1, at 98; AG 6-6). As such, for the reasons discussed above, we find that this proposal fails to satisfy the Department's sixth design guideline (Exhs. NG-CPIP-1, at 98; AG 6-6). Based on these considerations, the Department rejects the Company's overhead hardening for resiliency IPIM.

f. Service Quality Extension Metric IPIM

As noted, the Company proposes to further reduce acceptable SAIDI and SAIFI reliability performance levels following the final glide path step down (Exh. NG-CPIP-1, at 150). National Grid proposes that the incentive would apply only for the last two years of the five-year rate plan, with the level of performance for SAIDI to earn an incentive starting at one-third standard deviation from the average performance established in D.P.U. 12-120-D (Exh. NG-CPIP-1, at 151). The Company states that the addition of the incentive provides "added motivation to make improvements in the system that will result in exceptional reliability performance" (Exh. NG-CPIP-1, at 150). Similar to our findings above, we conclude that reliability is an activity that is clearly within the Company's public service obligation to provide safe and reliable service to customers. Thus, we conclude that the proposed SQ extension metric IPIM does not satisfy the Department's first threshold principle.

Further, as noted above in this Order, the Department has opened a proceeding, D.P.U. 24-53, on potential revisions to the SQ Guidelines. Given the nature of the Company's proposal, even if the IPIM satisfied our review criteria, we would be reluctant to approve it outside of the SQ docket, and ahead of any decisions reached in that proceeding. Based on these considerations, the Department rejects the Company's SQ extension metric IPIM.

g. Alternative IPIMs

As noted above, CLF, EDF, and Acadia Center recommend that the Department direct National Grid to propose and implement a single reliability IPIM that improves reliability in: (1) vulnerable communities with environmental justice populations experiencing worse than average reliability; and (2) the Company's worst performing feeders, specifically prioritizing communities with environmental justice populations (CLF Brief at 22-23; EDF Brief at 17-18; Acadia Center Brief at 19). The Department has reviewed the intervenors' recommendation (Exhs. EDF-CLF-JRC-1, at 40-42; EDF-CLF-JRC-Surrebuttal-1, at 9-11). As acknowledged by the intervenors, the record shows that over the past five years, the Company's environmental justice populations have experienced better than average reliability (Exhs. NG-PIMS-Rebuttal-1, at 77-79; EDF-CLF-JRC-Surrebuttal-1, at 9-10; EDF-CLF-2-30 & Att. 2). Further, we acknowledge the Company's concerns regarding the limits of measuring customer data within environmental justice populations without widespread AMI meters (Exhs. NG-PIMS-Rebuttal-1, at 78-79). The Department commends the Company for demonstrating that environmental justice populations have experienced better than average reliability over the past five years. The Department is not persuaded that a targeted IPIM, as recommended by these intervenors, is necessary or appropriate at this time. Nevertheless, we expect the Company to continue to maintain reliability standards in environmental justice populations and, where underperformance is identified, to take timely remedial action.

G. Performance Incentive Mechanisms

1. Introduction

In this proceeding, National Grid proposes five PIMs that the Company states are designed to encourage the achievement of specific, outcome-oriented goals that go beyond the scope of the Company's core business operations (Exh. NG-CPIP-1, at 173). According to National Grid, the proposed PIMs are consistent with the broad-based incentive regulation goals of the CPI Plan and complement it by adding focus on targeted outcomes that would not result from the CPI Plan alone or that could face performance pressures as the Company responds to the efficiency incentive of the CPI Plan (Exh. NG-CPIP-1, at 173).

National Grid states that each PIM is designed to be symmetrical, such that it penalizes the Company if it fails to deliver results above a target range and rewards the Company for exceptional performance (Exh. NG-CPIP-1, at 168-169). The Company proposes to report on

PIM performance and associated calculations in its annual PBR-O mechanism filing, to be filed on June 15 of each year (Exh. NG-CPIP-1, at 175).[38] National Grid proposes to include in each annual filing a report on the Company's prior calendar-year performance relative to each PIM, including the level of performance achieved and calculations for the incentives earned or penalties incurred and an explanation of any targets not achieved (Exh. NG-CPIP-1, at 175). National Grid proposes to include any incentives or penalties in the annual PBR-O rate calculation, subject to a final reconciliation at the end of the CPI Plan term (Exh. NG-CPIP-1, at 175).

The Company states that the proposed PIMs are conditioned on approval of the proposed PBR-O mechanism (Exh. NG-CPIP-1, at 176). According to National Grid, without the ongoing revenue support of the PBR-O mechanism over the five-year stay-out period, the Company would not be able to commit to the PIMs, because it would not have sufficient O&M cost recovery to commit to the deadband levels of performance in these areas and, therefore, it would be at increased risk of accruing penalties (Exh. NG-CPIP-1, at 176).

The five proposed PIMs address the following issues: (1) increased enrollment in the low-income discount program ("low-income discount PIM"); (2) first call resolution; (3) digital customer engagement; (4) fleet electrification; and (5) megawatts ("MW") of DER interconnected to the system ("DER interconnection PIM"). The Department discusses each proposed PIM in more detail below.

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[38] As the proposed term of the CPI Plan is five years and would expire on September 30, 2029, the Company proposes to submit its last filing relative to the PBR-O Mechanism on its calendar year 2029 performance on June 15, 2030 (Exh. NG-CPIP-1, at 175).

2. Company Proposal

a. Low-Income Discount PIM

National Grid proposes a low-income discount PIM to track the Company's efforts to increase enrollment of customers in the discount rate, i.e., Rate R-2 (Exh. NG-CPIP-1, at 176-177). The Company states that the major goal and benefit of the proposed low-income discount PIM is that increased enrollment in Rate R-2 would reduce the number of low-income households with a home energy burden above six percent (Exh. NG-CPIP-1, at 177).[39]

The proposed low-income discount PIM would have an annual target of enrolling 4,650 new qualifying low-income customers each calendar year, which the Company states is equal to three percent of 2023 enrollment and five times higher than the 2017 through 2023 per annum growth rate of 0.6 percent (Exhs. NG-CPIP-1, at 178; NG-CPIP-7, at 7; NG-CP-1, at 45). The proposed low-income discount PIM would have an annual symmetrical deadband of 750 customers, which would result in thresholds for penalty or incentive accruement at 3,900 and 5,400 annual customers enrolled, respectively (Exhs. NG-CPIP-1, at 179-180; NG-CPIP-7, at 7). For incremental enrollment beyond 5,400 customers, the Company would earn an incentive of $250 per customer up to a cap of $500,000 for enrolling 7,400 or more new customers (Exhs. NG-CPIP-1, at 179-180; NG-CPIP-7, at 7). For incremental enrollment below 3,900 new

39 The Company defines "energy burden" as the percentage of gross household income spent on energy costs (Exh. NG-CPIP-1, at 177). The Company states that according to the American Council for an Energy Efficient Economy's 2020 Energy Burden Report, an energy burden greater than six percent is considered high and an energy burden greater than ten percent is considered severe (Exh. NG-CPIP-1, at 177). Further, the Company notes that a 2022 Home Energy Affordability Gap study found that, without benefits, the average home energy burden for the poorest 586,500 Massachusetts households was eleven percent (Exh. NG-CPIP-1, at 177).

customers, the Company would incur a penalty of $250 per customer up to a cap of $500,000 for enrolling 1,900 or fewer new customers (Exhs. NG-CPIP-1, at 179-180; NG-CPIP-7, at 7). If new annual enrollment is above the maximum incentive threshold or below the maximum penalty threshold, the Company proposes for those incremental customers to be rolled over into the next year's report (Exh. NG-CPIP-1, at 180-181).

National Grid states that its low-income discount PIM is conditional on (1) incremental funding for targeted education and outreach, and (2) the hiring of incremental full-time equivalents ("FTEs") to help increase participation in and implement the low-income discount program, assist customers, develop and execute low-income strategies, and process customer applications (Exhs. NG-CPIP-1, at 181; NG-CP-1, at 46; NG-PIMS-Rebuttal-1, at 47-48). To increase enrollment numbers, the Company proposes to use a comprehensive customer outreach strategy to breach the typical barriers to enrollment in low-income programs, such as awareness of program offerings, eligibility, methods of enrollment, accessibility, and language barriers (Exhs. NG-CPIP-1, at 180; NG-CP-1, at 46).

b. First Call Resolution PIM

National Grid's proposed first call resolution PIM measures the percentage of customer calls resolved during the customer's initial phone call with Company representatives (Exh. NG-CPIP-1, at 189). The Company states that this metric is an industry standard that will increase customer satisfaction by resolving customer inquiries expeditiously (Exh. NG-CPIP-1, at 189, 193).

National Grid states that it has implemented a call center analytic solution to calculate and measure the proposed first call resolution PIM, using the call history and customer data to identify if a customer inquiry is a repeat inquiry within seven days (Exh. NG-CPIP-1, at 190). To set the customer resolution percentage target, National Grid used historical performance data, which showed that during 2022 and 2023, the Company resolved 68 percent and 72 percent, respectively, of its customer inquiries on the first call (Exh. NG-CPIP-1, at 190). Based on these results, the Company proposes to target resolving 70 percent or more of customer calls on the first call (Exhs. NG-CPIP-1, at 190; NG-CPIP-7, at 9).

National Grid proposes a symmetrical deadband of ten percent above or below the target, such that the Company will earn an incentive only if performance exceeds 80 percent each year, and it will pay a penalty only if the performance is below 60 percent each year (Exhs. NG-CPIP-1, at 190-191; NG-CPIP-7, at 9). National Grid proposes an incentive of $50,000 per percentage point above the upper deadband of 80 percent of first calls resolved, up to maximum total incentive of $500,000 if the Company resolves 90 percent or more of customer calls on the first call in any given year (Exhs. NG-CPIP-1, at 192; NG-CPIP-7, at 9). National Grid proposes a penalty of $50,000 per percentage point below the lower deadband of 60 percent of first calls resolved, up to a maximum total penalty of $500,000 if the Company resolves 50 percent or fewer of the first calls in any given year (Exhs. NG-CPIP-1, at 192; NG-CPIP-7, at 9).

c. Digital Customer Engagement PIM

National Grid's proposed digital customer engagement PIM is intended to expand customers' utilization of digital self-service tools, such as the Company's integrated voice response system, web portal, mobile devices, chatbot, texts, social media, and push notifications

(Exh. NG-CPIP-1, at 193-194).[40] National Grid states that the benefits of its proposed PIM include increased customer satisfaction by allowing customers to use their preferred channel of communication to interact with the Company, as well as a method to measure the adoption, utilization, and effectiveness of the Company's digital transactions, which in turn would encourage future customer service investments to achieve higher customer satisfaction (Exh. NG-CPIP-1, at 194-195, 198-199).

The Company proposes to measure the success of the digital customer engagement PIM by calculating the transactions completed by self-service and agent-handled channels to understand the digital customer engagement score (Exh. NG-CPIP-1, at 195-196). To set the customer transaction target, National Grid used historical performance data, which showed that: (1) in a five-month period in 2022 after beginning to measure this metric, the Company achieved 4,354,255 digital customer engagement transactions; and (2) over a period of eight months in 2023, the Company achieved 7,012,126 digital customer engagement transactions (Exh. NG-CPIP-1, at 196). Based on annualized projection of these totals, the Company proposes a target of achieving ten million digital customer engagement transactions for each year of the CPI Plan (Exhs. NG-CPIP-1, at 196; NG-CPIP-7, at 10).

National Grid proposes a symmetrical deadband of one million customer transactions above or below the target, such that the Company will earn an incentive only if it measures

[40] According to National Grid, the integrated voice response system is the second highest use channel through which customers are connecting with the Company (Exh. NG-CPIP-1, at 194). The Company also notes that its website chat feature generates the highest satisfaction score of its interaction channels (Exh. NG-CPIP-1, at 194).

eleven million digital customer transactions, and it will pay a penalty only if it is unable to reach nine million digital customer transactions each year (Exhs. NG-CPIP-1, at 196-197; NG-CPIP-7, at 10). National Gird proposes an incentive of $0.25 per digital customer transaction above the upper deadband of eleven million digital customer engagements, up to a maximum total incentive of $500,000 if the Company achieves 13 million or more digital customer engagements in any given year (Exhs. NG-CPIP-1, at 197-198; NG-CPIP-7, at 10). National Grid proposes a penalty of $0.25 per digital customer engagement below the lower deadband of nine million digital customer engagements, up to a maximum total penalty of $500,000 if the Company reaches seven million or fewer digital customer transactions in any given year (Exhs. NG-CPIP-1, at 197-198; NG-CPIP-7, at 10).

d. Fleet Electrification PIM

National Grid's proposed fleet electrification PIM is designed to reduce Scope 1 GHG emissions by replacing the Company's fleet of light-duty vehicles with battery-powered EVs (Exh. NG-CPIP-1, at 183-184).[41] The Company states that the replacement of internal combustion vehicles with EVs would align with planned vehicle replacement lifecycles where possible, though there may be limited early replacement of existing vehicles (Exh. NG-CPIP-1, at 184). To support the forecasted volume of EVs for the Company's fleet, it would install EV charging infrastructure (Exh. NG-CPIP-1, at 187).

[41] Scope 1 GHG emissions are direct emissions resulting from a company's use of fossil fuels or releases of GHG (e.g., fleet, heating, fugitive pipeline emissions). D.P.U. 23-80/D.P.U. 23-81, at 70 n.26.

The Company established annual cumulative targets for the number of EVs in its light-duty fleet based on the historical and projected increases required to reach 100 percent EVs by 2030 (Exhs. NG-CPIP-1, at 185; NG-PIMS-Rebuttal-1, at 59; DPU 35-9; AG 6-15; EDF-CLF 1-21). The Company proposes annual cumulative targets for the fiscal years during the term of the CPI Plan as follows: 2025 - 33 EVs; 2026 - 58 EVs; 2027 - 93 EVs; 2028 - 138 EVs; and 2029 - 188 EVs (Exhs. NG-PIMS-Rebuttal-1, at 59; DPU 35-9, Att. 3; EDF-CLF 1-21). National Grid proposes an annual symmetrical deadband of 20 percent of the target, such that in fiscal year 2025, for example, the Company will earn an incentive only if performance exceeds 40 EVs, and it will pay a penalty only if the performance is below 26 EVs (Exhs. NG-PIMS-Rebuttal-1, at 60; DPU 35-9, Att. 3). For fiscal year 2025, National Grid proposes an incentive of $8,500 per EV above the upper deadband of 40 EVs, up to maximum total incentive of $85,000 if the Company achieves 50 EVs (Exh. DPU 35-9, Att. 3). For fiscal year 2025, National Grid proposes a penalty of $8,500 per EV below the lower deadband of 26 EVs, up to a maximum total penalty of $85,000 if the Company achieves 17 EVs (Exh. DPU 35-9, Att. 3). In addition to the annual cumulative target, the Company proposes that the deadbands, incentives, and penalties change each fiscal year (Exhs. NG-CPIP-1, at 185-187; NG-PIMS-Rebuttal-1, at 59; DPU 35-9, Att. 3; AG 6-15; EDF-CLF 1-21).

National Grid states that the plan to acquire EVs is heavily reliant on external factors beyond the Company’s control, such as a supplier delay, order cancellation, or inability to order vehicles that meet specifications (Exh. NG-CPIP-1, at 188). As such, National Grid proposes tariff language that would allow the Company to present evidence in its annual PBR-O rate adjustment filing to support a request for a penalty waiver if it fails to procure the number of EVs above the lower deadband (Exh. NG-CPIP-1, at 188; proposed M.D.P.U. No. 1528, App. A at II).

e. DER Interconnection PIM

National Grid's proposed DER interconnection PIM is intended to gauge the Company's efforts in interconnecting solar and battery storage projects onto the distribution system (Exh. NG-CPIP-1, at 199). The Company plans to use four approaches to achieve its target: (1) improving the DG interconnection process; (2) implementing the online application proposed in the ESMP proceeding and other tools to simplify DG application process automation; (3) establishing DG key account management; and (4) conducting customer outreach (Exh. NG-CPIP-1, at 203).

National Grid proposes an annual target of 175 MW each calendar year based on the Company's recent historical performance (Exhs. NG-CPIP-1, at 201; NG-PIMS-Rebuttal-1, at 64; DPU 22-12). The Company states that it has observed interconnection saturation in several areas, requiring significant upgrades to install solar and storage (Exhs. NG-PIMS-Rebuttal-1, at 67-68; DPU 22-12). Therefore, National Grid proposes an upper deadband to align with the Company's five-year historical average of 206 MW and to incentivize the acceleration of interconnection given the expected downtrend until the upgrades are complete (Exhs. NG-PIMS-Rebuttal-1, at 68; DPU 22-12; DPU 35-11). Specifically, National Grid proposes a symmetrical deadband of 35 MW of DER interconnection each year (i.e., 20 percent of the 175 MW target level), such that the Company will earn an incentive only if performance exceeds 210 MW each year, and it will pay a penalty only if the performance is below 140 MW each year (Exhs. NG-CPIP-1, at 201-204; NG-CPIP-7, at 11; NG-PIMS-Rebuttal-1, at 64-65;

DPU 22-12; DPU 35-11). National Grid proposes an incentive of $16,667 per MW of DER interconnected above the deadband of 210 MW, up to a maximum total incentive of $1.5 million if the Company interconnects 300 MW or more of DER in any given year (Exhs. NG-CPIP-1, at 202-204; NG-CPIP-7, at 11). Similarly, National Grid proposes a penalty of $16,667 per MW of DER interconnected below the lower deadband of 140 MW, up to a maximum total penalty of $1.5 million if the Company interconnects 50 MW or less of DER in any given year (Exhs. NG-CPIP-1, at 202-204; NG-CPIP-7, at 11).

The Company states that its proposal is dependent on external factors, such as state and federal incentive programs and DER deployment industry conditions, that will contribute to significant variability in the annual amount of DER interconnected (Exh. NG-CPIP-1, at 204). As a result, the Company proposes that in any year where the Company interconnects MWs of DER above the maximum incentive threshold or below the maximum penalty threshold, the remaining MWs of DER beyond the cap would be rolled over into the next calendar year (Exh. NG-CPIP-1, at 204).

3. Positions of the Parties

a. Introduction

The Attorney General and DOER argue that the Company's proposed PIMs violate the Department's design guidelines (Attorney General Brief at 25, citing Exh. AG-WG-1, at 29; DOER Brief at 53). The Attorney General proposes two alternative PIMs, as discussed below. Further, while DOER supports the Company's goals of affordability, advancing customer engagement, GHG emissions reductions, and clean energy adoption, DOER asserts that the proposed PIMs lack aggressive targets or reward the Company for activities it otherwise would be incented to pursue, and they should be rejected (DOER Brief at 53, 56). DOER also argues that the proposed PIMs need refinement from a broad stakeholder group, so the Department should address PIMs in a comprehensive manner during a separate phase of the ESMP proceedings (DOER Brief at 56-61; DOER Reply Brief at 6-7).

CLF, EDF, and Acadia Center argue that the Department should reject or modify most of National Grid's proposed PIMs because they incentivize actions that fall within the Company's public service obligation or otherwise fail to meet the Department's design guidelines (CLF Brief at 20-22; EDF Brief at 18; Acadia Center Brief at 16). These intervenors propose several alternative PIMs, as discussed below. MEDA and TEC and PowerOptions do not advocate for the rejection of all of the Company's proposed PIMs, but they do address specific proposals, as set forth below. No other intervenor commented on the Company's proposed PIMs.

The Company asserts that its PIMs should be approved as an integral component of the overall CPI Plan (Company Brief at 236). As discussed below, the Company argues that there is an insufficient record in this case to implement any of the intervenors' alternative PIMs (Company Brief at 232).

b. Low-Income Discount PIM

i. Intervenors

The Attorney General, CLF, EDF, MEDA, TEC and PowerOptions, and Acadia Center assert that the Company's proposed low-income discount PIM should be rejected. These intervenors maintain that the low-income discount PIM does not meet the Department's standard for PIM approval (Attorney General Brief at 34; CLF Brief at 20; EDF Brief at 19-20; MEDA Brief at 37-39; TEC and PowerOptions Brief at 14-15; Acadia Center Brief at 18). Specifically, EDF, CLF, MEDA, and Acadia Center argue that the low-income discount PIM fails the Department's threshold principle that a PIM must be outside of the utility's public service obligation because the Company already has an obligation to conduct outreach to and enroll customers who qualify for Rate R-2 (CLF Brief at 20; EDF Brief at 19-20; MEDA Brief at 37-39; TEC and PowerOptions Brief at 14-15; Acadia Center Brief at 18).

The Attorney General, MEDA, and TEC and PowerOptions also argue that the number of ratepayers enrolled in a low-income discount rate does not adequately measure or pursue the goal of affordability (Attorney General Brief at 33-34; MEDA Brief at 39; TEC and PowerOptions Brief at 14-15). More specifically, the Attorney General argues that the low-income discount PIM does not serve as a measurement of affordability for ratepayers, making it an inadequate PIM to serve the Commonwealth's affordability goals, as enrolling a customer on Rate R-2 does not necessarily mean the customer will no longer be energy burdened (Attorney General Brief at 33-34). In this regard, the Attorney General also asserts that the proposed low-income discount PIM does not encourage program performance that best achieves the Commonwealth's goal of energy affordability and violates the Department's first design guideline (Attorney General Brief at 34).

MEDA argues that National Grid's proposed PIM violates the Department's second and third design guidelines, as it is unclear how the Company will be able to specifically connect the new discount rate enrollee population with the outreach efforts for which it requests cost recovery (MEDA Brief at 38, citing Exh. MEDA 1.0, at 40 (Rev.)). As an example, MEDA contends that outside sources such as word of mouth, independent customer investigation, economic conditions, and organizations such as community action program agencies ("CAP agencies"), can drive increased enrollment in the Company's Rate R-2 (MEDA Brief at 38, citing Exh. MEDA 1.0, at 40 (Rev.); MEDA Reply Brief at 15). MEDA contends that because it is unclear whether enrollment that stems from outside sources can be differentiated from enrollment due to National Grid's outreach efforts, the Company may not play a clear and distinct role in increasing enrollment (MEDA Brief at 38).

CLF, EDF, and MEDA also argue that the enrollment targets are not substantially high enough above current enrollment rates, as the Company was able to enroll far more than 4,650 customers in both 2021 and 2023 (CLF Brief at 20, citing Exh. EDF-CLF-JRC-1, at 45; EDF Brief at 20 citing Exh. EDF-CLF-JRC-1, at 45; MEDA Brief at 38-39, citing Exh. NG-CPIP-1, at 178; MEDA Reply Brief at 15-16). CLF and EDF also argue that the Company's Rate R-2 is insufficient as proposed and that rectifying the design of the discounted rate would result in increased engagement with customers and raise the enrollment in Rate R-2, without the need for the low-income discount PIM (CLF Brief at 20; EDF Brief at 20). EDF asserts that the low-income discount PIM should be rejected, but if the Department approves the proposal, the performance target should be raised to recognize both the Company's past performance levels and the increase in enrollment that will result from the improved Rate R-2 structure (EDF Brief at 20-21).

The Attorney General offers an alternative affordability PIM that she asserts should be accepted in place of the proposed low-income discount PIM (Attorney General Brief at 38). The Attorney General's proposed affordability PIM measures annual increases in the Company's revenue requirement relative to the increase in the Consumer Price Index over the same year, with deadbands established at percentage points above and below the average (Attorney General

Brief at 38, citing Exh. AG-WG-1, at 33-34, 39; Consumer Price Index, U.S. Board of Labor Statistics). The Attorney General contends that if National Grid's revenue requirement increases above the upper deadband, the Company would incur a penalty, and if the revenue requirement were to increase by a lower percentage than the lower deadband relative to the Consumer Price Index, the Company would earn a reward (Attorney General Brief at 38). The Attorney General argues that her proposed affordability PIM would better serve the goal of reducing customers' energy burdens because the Company would be incentivized to keep its revenue requirement increases below that of customers' other basic goods and services (Attorney General Brief at 38-39; Attorney General Reply Brief at 13). In this regard, the Attorney General rejects the notion that a utility's costs are not linked to the Consumer Price Index and maintains that the point of the affordability PIM is to reward the Company for not raising the energy burdens of its customers (Attorney General Reply Brief at 13).

CLF and EDF propose an alternative low-income delivered fuels customer electrification PIM, which Acadia Center supports, to increase installation of heat pumps for low-income customers who use delivered fuels such as oil or propane for heating, which these intervenors claim are currently being installed at a rate lower than the Company's general customer base. (CLF Brief at 24; EDF Brief at 27-28; Acadia Center Brief at 20; CLF, EDF and Acadia Center Reply Brief at 6-7). These intervenors argue that in addition to reducing GHG emissions and advancing Massachusetts' clean energy future, a PIM that promotes installation of heat pumps will reduce costs for participating customers because heating with delivered fuels is more expensive than heating with electric heat pumps (CLF Brief at 24, citing Exh. EDF-CLF-JRC-1, at 60; EDF Brief at 28). CLF and EDF submit that the Company should work with stakeholders to develop such a PIM with specific targets, incentives, and metrics (CLF Brief at 24; EDF Brief at 29). Alternatively, CLF and EDF assert that the Department could direct the Company to develop the aforementioned PIM as part of its next three-year energy efficiency plan proceeding (CLF Brief at 24; EDF Brief at 30).[42]

MEDA also proposes an affordability PIM in lieu of the Company's proposed low-income discount PIM (MEDA Brief at 43). MEDA asserts that its proposed PIM is designed to achieve over the five-year PBR-O plan term a ten-percent reduction in residential disconnections for non-payment in the 20 zip codes in the Company's service territory with the highest 2023 disconnections ratios (MEDA Brief at 43, citing Exh. MEDA 1.0, at 51 (Rev.)). MEDA argues that its proposed affordability PIM will reduce racial inequities in utility access and will serve as a more direct method of keeping customers connected to electric service, which MEDA asserts is a more direct indicator that utility service is affordable (MEDA Brief at 44). MEDA recommends that the Department reject the Attorney General's proposed affordability PIM (MEDA Reply Brief at 18-19).

In response to the Attorney General's and MEDA's alternative PIMs, TEC and PowerOptions argue that if the Department approves an alternative affordability metric or metrics, then the Department should ensure it is broad and inclusive as well as minimizing rate increases for all customers (TEC and PowerOptions Brief at 15).

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42 The Attorney General argues that incentives for energy efficiency measures should be part of the three-year energy efficiency planning process and not part of the instant proceeding (Attorney General Reply Brief at 13-14). As such, the Attorney General recommends that the Department reject the proposed low-income delivered fuels customer electrification PIM (Attorney General Reply Brief at 14).

ii. Company

The Company argues that its proposed low-income discount PIM advances the Commonwealth's public policy goal of reducing energy burdens for low-income customers (Company Brief at 211, citing Exh. NG-PIMS-Rebuttal-1, at 49). The Company maintains that it will be rewarded only for exceptional performance in raising Rate R-2 enrollment numbers and that it will reduce energy burdens in doing so (Company Brief at 211). National Grid additionally notes that its proposed PIM holds the Company accountable in the event of under-performance in enrollment numbers (Company Brief at 211-212). Further, the Company contends that the proposed PIM does not duplicate rewards, and that the proposed target is measurable and verifiable and based on historical data (Company Brief at 212).

With respect to intervenors' alternative PIMs, the Company argues that the Attorney General's proposed affordability PIM should be rejected (Company Brief at 233). The Company contends that conceptually the Attorney General's affordability PIM may be insightful if applied to all utilities in the Commonwealth, so it would be more appropriate for consideration in the Department's energy burden proceeding in Energy Burden Inquiry, D.P.U. 24-15 (Company Brief at 233, citing Exh. NG-PIMS-Rebuttal-1, at 71-72). Additionally, the Company contends that the Attorney General's proposal is inappropriate because EDCs have limited control over their costs, and these costs are not commensurate with that of the Consumer Price Index or other economy-wide indices (Company Brief at 233-234). The Company further emphasizes that its influence over relevant considerations such as customer bills and disconnections is limited in scope (Company Reply Brief at 42, citing Exh. NG-PIMS-Rebuttal-1, at 71-72).

Regarding the heat pump-related PIM proposed by CLF and EDF and supported by Acadia Center, National Grid argues that the proposal is not adequately designed and that the Company is incentivized already through the three-year energy efficiency plans to help income-qualified customers convert to electric heat pumps (Company Brief at 235, citing Exh. NG-PIMS-Rebuttal-1, at 80). National Grid argues that MEDA's proposed affordability PIM is misplaced, as the Company can only offer assistance and raise awareness of the customer's options and that simply refraining from disconnecting customers does not promote affordability (Company Brief at 235, citing Exh. NG-PIMS-Rebuttal-1, at 83-84; Company Reply Brief at 43). Further, National Grid contends that MEDA's proposed affordability PIM is too myopic in that it applies only to customers in specific zip codes, whereas the Company's proposed low-income discount PIM treats all income-eligible customers equally (Company Brief at 235, citing Exh. NG-PIMS-Rebuttal-1, at 84). In addition, National Grid argues that the PIM requires the collection of sensitive data, and the Company does not collect any customer racial or ethnic data in its billing system, nor does it take any service actions based on race or ethnicity (Company Reply Brief at 44, citing Exh. NG-PIMS-Rebuttal-1, at 84).

c. First Call Resolution PIM and Digital Customer Engagement PIM

i. Intervenors

The Attorney General, CLF, EDF, and Acadia Center assert that the Company's proposed first call resolution PIM and digital customer engagement PIM should be rejected. The Attorney General argues that the Company's proposed PIMs would duplicate a reward available for the same action through another mechanism and violate the Department's sixth design guidelines (Attorney General Brief at 36; Attorney General Reply Brief at 9). More specifically, the

Attorney General contends that resolving inquiries on the first call or shifting customers from traditional to digital interactions would reduce the Company's O&M spending and enhance its earnings, while also providing the opportunity for the Company to recover a monetary incentive (Attorney General Brief at 36-37, citing Exh. AG-WG-1, at 30).

CLF argues that the proposed first call resolution PIM should be rejected, as proposed, and CLF, EDF, and Acadia Center contend that the target is not ambitious enough, as the 70-percent first call resolution target does not exceed current levels of performance (CLF Brief at 21; EDF Brief at 21-22; Acadia Center Brief at 18; CLF, EDF, and Acadia Center Reply Brief at 6). CLF and EDF argue that the proposed digital customer engagement PIM would reward the Company for activities already within its existing public service obligation and, therefore, fails to satisfy one of the two threshold principles for approval (CLF Brief at 21; EDF Brief at 22-23). These intervenors also contend that the proposed PIM is similar to the customer ease PIM that was proposed, and rejected, in the Company's last base distribution rate case (CLF Brief at 21, citing Exh. EDF-CLF-JRC-1, at 47-48; EDF Brief at 23, citing D.P.U. 18-150, at 122). Further, CLF and EDF, with Acadia Center's support, claim that the proposed target of ten million customer transactions is not robust enough based on the Company's performance in 2022 and 2023 of approximately 10,450,212 and 10,518,189 customer service transactions, respectively (EDF Brief at 23; Acadia Center Brief at 18; CLF, EDF, and Acadia Center Reply Brief at 6). These intervenors assert that if the Department approves a digital customer engagement PIM, the annual target should be increased (EDF Brief at 23; Acadia Center Brief at 18; CLF, EDF, and Acadia Center Reply Brief at 6).

ii. Company

National Grid asserts that efforts to resolve customer inquiries on the first call and to increase digital customer transactions are stretch goals for the Company within its public service obligation to provide safe, reliable, and least-cost service to customers (Company Brief at 217, citing Exh. NG-PIMS-Rebuttal-1, at 52, 56; D.P.U. 18-150, at 53). Further, the Company contends that these proposed PIMs are simple, innovative ways to advance the Commonwealth's public policy goal of improved customer service by incentivizing performance beyond the normal expected range and penalize performance below the normal expected range (Company Brief at 214-215, 217-218, citing Exh. NG-PIMS-Rebuttal-1, at 52-53, 56-57; Company Reply Brief at 38). The Company asserts that these factors avoid any perverse incentive by providing accountability and discouraging overspending (Company Brief at 215, 218, citing Exh. NG-PIMS-Rebuttal-1, at 54, 57; Company Reply Brief at 37).

d. Fleet Electrification PIM

i. Intervenors

The Attorney General, DOER, CLF, EDF, and Acadia Center assert that the Department should reject the Company's fleet electrification PIM. The Attorney General argues that the proposed Fleet Electrification PIM violates two of the Department's guidelines (Attorney General Brief at 35). First, the Attorney General contends that the fleet electrification PIM creates a perverse incentive by encouraging capital spending regardless of outcomes, violating the Department's fifth design guideline (Attorney General Brief at 35; Attorney General Reply Brief at 11). Because the Company will track only inputs in this proposed PIM, not the resulting reduced emissions and pollution, the Attorney General argues that the fleet electrification PIM encourages spending regardless of its value to ratepayers (Attorney General Brief at 35). Second, the Attorney General asserts that achieving the goals of this PIM is largely dependent on the Company's spending on EVs and related support infrastructure (Attorney General Brief at 35). As a result, the Attorney General states that such investments would be recoverable as rate base or O&M, so the Company would receive duplicative rewards for the same action in violation of the Department's sixth design guideline (Attorney General Brief at 35; Attorney General Reply Brief at 11).

Further, the Attorney General contends that the Company's proposal inappropriately includes a force majeure "escape" from the penalty provisions of the PIM (Attorney General Reply Brief at 11, citing Company Brief at 24). Because the Company does not propose a symmetrical force majeure clause recognizing that external factors may aid the Company in achieving its target, the Attorney General argues this PIM is not symmetrical (Attorney General Reply Brief at 11).

DOER, CLF, EDF, and Acadia Center argue that the proposed fleet electrification PIM provides an incentive for actions to which the Company has already committed in establishing a goal to achieve 100-percent fleet electrification by 2030 (DOER Brief at 56, citing Exh. EDF-CLF-JCR-1, at 45; CLF Brief at 20; EDF Brief at 21; Acadia Center Brief at 18; CLF, EDF, and Acadia Center Reply Brief at 6). EDF also argues that the Company should pursue electrification to meet shareholder expectations without additional financial incentives (EDF Brief at 21). CLF and EDF also contend that the proposed PIM is too narrow and should be expanded to include medium- and heavy-duty vehicles (CLF Brief at 21; EDF Brief at 21).

ii. Company

National Grid asserts that increasing its electrified fleet is a stretch goal for the Company within its public service obligation to provide safe, reliable, and least-cost service to customers (Company Brief at 221-222, citing Exh. NG-PIMS-Rebuttal-1, at 60; D.P.U. 18-150, at 53). Further, the Company contends that the proposed PIM is a simple, innovative way to advance the Commonwealth's public policy goal of reducing GHG emissions performance beyond the normal expected range and penalizes performance below the normal expected range (Company Brief at 222-223, citing Exh. NG-PIMS-Rebuttal-1, at 61; Company Reply Brief at 38). The Company asserts that these factors avoid any perverse incentive by providing accountability and not encouraging overspending (Company Brief at 223, citing Exh. NG-PIMS-Rebuttal-1, at 61; Company Reply Brief at 37).

e. DER Interconnection PIM

i. Intervenors

The Attorney General asserts that the Company's proposed DER interconnection PIM violates the Department's threshold principles and two of the Department's design guidelines. First, the Attorney General argues that interconnecting new customers is part of the Company's public service obligation and, therefore, the proposed PIM fails to satisfy the Department's second threshold principle (Attorney General Brief at 37). Further, the Attorney General contends the proposed PIM violates the Department's third design guideline because achieving targets would be heavily reliant on factors outside of the Company's control (Attorney General Brief at 37). In addition, the Attorney General claims that absent a cost-effectiveness aspect, the proposed PIM creates a perverse incentive to spend regardless of outcome, thus violating the Department's fifth design guideline (Attorney General Brief at 37-38).

The Attorney General argues that to avoid the perverse incentives created by the Company's proposed PIM, and to better advance the Commonwealth's climate and clean energy goals, the Department should approve a clean energy adoption PIM to measure increases in MW of DER hosting capacity added to the Company's system per $1.0 million of capital spending (Attorney General Brief at 39, citing Exh. AG-WG-1, at 38-40). The Attorney General contends that her proposed PIM would incentivize cost-effective capacity improvements and encourage the Company to invest time and capital in improvements where additional DER capacity can be added at the least cost (Attorney General Brief at 39).

CLF, EDF, and Acadia Center argue that the DER interconnection PIM should be rejected because it incentivizes actions within the Company's public service obligations and, therefore, violates the Department's second threshold principle (EDF Brief at 24; CLF, EDF, and Acadia Center Reply Brief at 5). In addition, these intervenors claim that the Company has not demonstrated sufficient control over the proposed PIM's desired outcome of additional MWs of interconnected DER in violation of the Department's third design guideline (CLF Brief at 22; EDF Brief at 24; CLF, EDF, and Acadia Center Reply Brief at 5-6). Although Acadia Center joined CLF and EDF in filing a reply brief, Acadia Center does not support rejecting the proposed DER interconnection PIM (Acadia Center Brief at 20). Rather, Acadia Center argues that the proposed PIM has unreasonably low performance targets relative to the Company's historical performance and, therefore, the target and deadbands should be modified so that ratepayers do not overpay for service (Acadia Center Brief at 19-20).

CLF, EDF, and Acadia Center also recommend that the Department direct National Grid to develop and propose an incremental peak load reduction PIM to incentivize the Company to proactively implement programs that deliver benefits to ratepayers (CLF Brief at 22; EDF Brief at 24-27, citing Exh. EDF-CLF-JRC-1, at 50-55; Acadia Center Brief at 20; CLF, EDF, and Acadia Center Reply Brief at 8-9). These intervenors submit that the Department should direct the Company to work with stakeholders to develop those proposals (including specific targets, incentives, and penalties) following the instant proceeding and submit those proposals for consideration in a future filing (EDF Brief at 26-27; CLF, EDF, and Acadia Center Reply Brief at 7, 8).

ii. Company

National Grid asserts that interconnecting additional DER to the Company's distribution system is a stretch goal for the Company within its public service obligation to provide safe, reliable, and least-cost service to customers (Company Brief at 224, citing Exh. NG-PIMS-Rebuttal-1, at 65; D.P.U. 18-150, at 53). Further, the Company contends that the proposed PIM is a simple, innovative way to advance the Commonwealth's public policy goal of reducing GHG emissions performance beyond the normal expected range and penalize performance below the normal expected range (Company Brief at 226, citing Exh. NG-PIMS-Rebuttal-1, at 66-67; Company Reply Brief at 38). The Company asserts that these factors avoid any perverse incentive by providing accountability and not encouraging overspending (Company Brief at 227, citing Exh. NG-PIMS-Rebuttal-1, at 67; Company Reply Brief at 37).

National Grid takes issue with the Attorney General's recommendation to replace the Company's proposed PIM with a clean energy adoption PIM (Company Brief at 232-233). The Company argues that the Attorney General's proposed metric will not drive an increase in DER adoption and is targeted only towards a subset of DER (Company Brief at 233, citing Exh. NG-PIMS-Rebuttal-1, at 73-74). More specifically, National Grid contends that the Attorney General's proposed PIM does not address value drivers for DER customers, namely cost, timeliness, and ease of doing business, whereas the Company's proposed PIM aims to improve these value drivers for DER customers (Company Brief at 233, citing Tr. 6, at 852, 858). Further, National Grid argues that CLF's and EDF's proposed peak load reduction PIM is aimed at different policy objectives than the Company's DER interconnection PIM, and that any incentive for peak load reducing efforts is better addressed in the three-year energy efficiency plan process (Company Brief at 234-235, citing Exh. NG-PIMS-Rebuttal-1, at 79-80).

f. Other Issues

In addition to the alternative PIMs discussed above, the Attorney General argues that the Department should approve a SQ PIM focused on reducing long-duration outages by measuring the percentage of customers without service for more than 24 hours (Attorney General Brief at 39, citing Exh. AG-WG-1, at 35, 39-40). The Attorney General contends that with the proliferation of home-heating electrification, eliminating long-duration outages becomes one of the most important reliability metrics, as customers will be wholly reliant on the electric system to heat their homes during the winter (Attorney General Brief at 39, citing Exh. AG-WG-1, at 34; Tr. 6, at 790). The Attorney General also claims that this proposed PIM would encourage the Company to restore service and build for resiliency during major summer storm events such as hurricanes (Attorney General Brief at 40). The Attorney General proposes a target value for this PIM at zero customers without service for more than 24 hours, with an "appropriate lower deadband" established to penalize the Company for underperformance (Attorney General Brief at 40). National Grid does not support the Attorney General's proposed SQ PIM and argues that the Company already reports this information, and the proposed 24-hour timeframe may drive further investment not contemplated in this proceeding (Company Brief at 233, citing Exh. NG-PIMS-Rebuttal-1, at 72-73).

CLF and EDF, with support from Acadia Center, propose a workplace diversity PIM to encourage National Grid to increase the diversity of its workforce by hiring a greater proportion of under-represented identities, including but not limited to, people who identify as: women; Black, Indigenous, and people of color; LGBTQIA+; returning citizens (i.e., formerly incarcerated individuals); and persons with disabilities (CLF Brief at 24-25, citing Exhs. EDF-CLF-JRC-1, at 63-64; EDF-CLF-MW-1, at 10; EDF Brief at 30; Acadia Center Brief at 20). CLF and EDF argue that the Company should develop a baseline based on at least five years of historic data (i.e., average workforce diversity over the past five years), and the PIM should target significant year-over-year improvement over that baseline (CLF Brief at 24; EDF Brief at 31). These intervenors assert that the Department should direct the Company to work with stakeholders to develop specific targets, incentives, and penalties following the instant proceeding and to submit those proposals for the Department's consideration in a future filing (CLF, EDF, and Acadia Center Reply Brief at 7). National Grid maintains that it supports the intent of the proposal and is committed to advancing diversity, equity, and inclusion through meaningful steps, but the Company asserts that it does not track this goal in the manner proposed by CLF and EDF and, therefore, a stakeholder process may be appropriate for developing this type of measure (Company Brief at 235, citing Exh. NG-PIMS-Rebuttal-1, at 80-82).

Acadia Center argues that the Department should consider a building electrification PIM to incentivize the adoption of electric and ground-source heat pumps, building envelope improvements, and other building electrification solutions (Acadia Center Brief at 20). Acadia Center also urges the Department to consider a light-duty vehicle electrification PIM to incentivize lifetime metric tons of carbon dioxide equivalent reductions from light-duty EV deployment in National Grid's service territory, but not owned by the Company (Acadia Center Brief at 20).

4. Analysis and Findings

a. Introduction

As noted above, the Company states that the proposed PIMs are conditioned on approval of the proposed PBR-O mechanism (Exh. NG-CPIP-1, at 176). As noted above, the Department approved the Company's PBR-O mechanism. As such, we address the Company's PIMs as proposed. The review criteria for the Company's PIMs are set forth in Section IV.F.4.b. above.

b. Low-Income Discount PIM

National Grid proposes a PIM to track the Company's efforts to increase enrollment of customers in Rate R-2, based on an annual target of 4,650 new qualifying low-income customers (Exhs. NG-CPIP-1, at 176-178; NG-CPIP-7, at 7; NG-CP-1, at 45). The Attorney General, DOER, CLF, EDF, MEDA, and Acadia Center assert that the Company's proposed low-income discount PIM should be rejected. Additionally, several of these intervenors propose alternative affordability PIMs.

As an initial matter, the Department has expressed a preference for a symmetrical structure for PIMs, in which a company earns an incentive for exceeding a target and incurs a penalty for under-performing relative to the target. D.P.U. 20-120, at 134. The Company's proposed low-income discount PIM incorporates symmetrical deadbands around a target level of incremental customers added to the low-income discount each year (Exhs. NG-CPIP-1, at 179-180; NG-CPIP-7, at 7). The Company earns an incentive for each new customer enrolled in the program above the upper deadband, and the Company incurs a penalty for each customer that was not added to the program below the lower deadband (Exhs. NG-CPIP-1, at 179-180; NG-CPIP-7, at 7). The Department finds the Company's proposed PIM structure is acceptable.

As noted above, several intervenors argue that the Company's proposed low-income discount PIM does not meet the threshold requirements for approval (CLF Brief at 20; EDF Brief at 19-20; MEDA Brief at 37-39; TEC and PowerOptions Brief at 14-15; Acadia Center Brief at 18). The Department has determined that affordability is an important public policy goal in the Commonwealth. D.P.U. 24-15, Vote and Order Opening Inquiry at 4-5 (January 4, 2024); D.P.U. 22-22, at 469, 472; Investigation into Role of Gas Local Distribution Companies as Commonwealth Achieves Target 2050 Climate Goals, D.P.U. 20-80-B at 16 (2023). Further, we recognize that the Company's Rate R-2 is one of several important components of lowering the energy burdens for income-eligible households (Exh. NG-CPIP-1, at 177). As discussed in Section XVI.A.2.c. below, the Department directs the Company to implement a five-tiered discount for qualifying income-eligible customers, designed to offer higher discounts to customers at lower income levels, and to assist the spectrum of income-eligible customers in managing their electric energy burdens. In this regard, we note that there is a tangible gap between the total number of income-eligible customers, which the Company estimates to be 390,000, and those currently enrolled in the low-income discount program, which was 153,379 customers in December 2023 (Exhs. NG-CP-1, at 25-26; LI-NG 1-14, at 2). To address these issues, the Department makes findings with respect to the Company's verification, education, and outreach efforts relative to income-eligible customers, as well as the hiring of incremental FTEs for these efforts in Sections XVI.A.3.c. and XVI.A.4.c. below. We find that the Company's proposed PIM will advance the important policy goal of affordability and will complement the Department's decisions relative to the low-income discount program. As such, the proposed PIM meets the Department's first threshold principle.

Further, we are persuaded that National Grid's proposed PIM will encourage the Company to go beyond its statutory obligation in G.L. c. 164, § 1F(4) to conduct substantial outreach to make the low-income discount available to income-eligible customers, as the Company intends to focus incremental resources and management attention on addressing impediments that have perpetuated the gap between income eligibility and actual enrollment, including program and eligibility awareness, ways to enroll, accessibility, and language barriers (see, e.g., Exhs. NG-CPIP-1, at 180; NG-CP-1, at 34-39; NG-CP-6; NG-CP-7; NG-PIMS-Rebuttal-1, at 48-49; DPU 14-4; DPU 14-5; DPU 39-3; AG 18-10, AG 18-12; AG 18-16; AG 18-18; AG 18-19; LI-NG 1-14). Additionally, the proposed PIM's target level over the PBR-O term represents a 15-percent increase in year-end 2023 enrollment. In the event the Company maximizes the incentive and enrolls 7,400 new customers over the PBR-O term, it would represent a 24-percent increase over the December 2023 customer enrollment level. We find that the Company's target and upper deadband are ambitious objectives and, if achieved, will represent a meaningful year-to-year increase in customer enrollment. Based on these considerations, we conclude that, in this instance, the Company's enhanced efforts to increase low-income discount enrollment through the proposed PIM satisfy the Department's second threshold principle.

Several intervenors also argue that the Company's proposed PIM does not meet our design guidelines. The Attorney General, MEDA, and TEC and PowerOptions argue that the number of ratepayers enrolled in a low-income discount rate does not adequately measure or pursue the goal of affordability (Attorney General Brief at 33-34; MEDA Brief at 39; TEC and PowerOptions Brief at 14-15). More specifically, the Attorney General argues that the Company's proposed PIM does not meet the Department's first design guideline to encourage program performance that best achieves the Commonwealth's energy goals because it neither serves as a measurement of, nor incentivizes, affordability for ratepayers (Attorney General Brief at 33-34). We disagree. As discussed, the proposed PIM is designed to increase the net number of customers enrolled in the low-income discount rate through enhanced efforts to identify, reach, educate, and enroll a group of income-eligible customers who will benefit most from a discounted rate. The proposed PIM encourages performance to address the electric energy burden for vulnerable customers and, in conjunction with the modifications to the low-income discount discussed later in this Order, contributes to the Commonwealth's energy goals that must prioritize affordability. We acknowledge that there are numerous factors that likely increase energy burdens, some of which will be addressed in different dockets, such as D.P.U. 24-15 (energy burden inquiry) and D.P.U. 24-148 (three-year energy efficiency plan to be filed on or before October 31, 2024). Thus, we find that the proposed PIM meets the Department's first design guideline.

MEDA argues that National Grid's proposed PIM violates the Department's second and third design guidelines because it will be difficult to delineate whether new low-income discount enrollments result from the Company's efforts or outside sources (MEDA Brief at 38, citing Exh. MEDA 1.0, at 40 (Rev.); MEDA Reply Brief at 15). The Department finds that National Grid's goal to enroll new income-eligible customers is clearly defined by the PIM's target and deadbands, and this goal and the Company's efforts at achieving it can be sufficiently monitored, quantified, and verified after the fact through annual filings (Exh. NG-CPIP-1, at 175, 178). Further, the hiring of additional staff for outreach and educational purposes should adequately serve as a measure of the cost of achieving the target enrollment numbers in the context of the potential quantifiable benefits to income-eligible customers. D.P.U. 18-150, at 121. Thus, we are satisfied that the proposed PIM meets the Department's second design guideline. Moreover, we find that the Company's enhanced outreach efforts, while not the exclusive factor in new low-income discount enrollments, constitutes a clear and distinct role in achieving the desired outcome (Exhs. NG-CPIP-1, at 180; NG-CP-1, at 34-39; NG-CP-6; NG-CP-7; NG-PIMS-Rebuttal-1, at 48-49; DPU 14-4; DPU 14-5; DPU 39-3; AG 18-12; AG 18-16; AG 18-18; AG 18-19; LI-NG 1-14). Thus, we conclude that the Company's proposal meets the Department's third design guideline.

The Department has reviewed the Company's proposed low-income discount PIM and finds that it meets the remaining design guidelines. D.P.U. 18-150, at 121-122. Accordingly, we approve the Company's low-income discount PIM, as proposed. The Company shall report on its PIM performance and associated calculations in its annual PBR-O mechanism to be submitted by June 15 of each year. The low-income PIM report shall include a summary of the Company's prior calendar-year performance, including the level of performance achieved, calculations for incentives earned or penalties incurred, and an explanation if the target level was not achieved (Exh. NG-CPIP-1, at 175). The Company also shall provide with the filing a complete accounting of its spending on outreach and education efforts to raise customer enrollment in the low-income discount program and the incremental labor expense associated with these activities (Exhs. NG-CPIP-1, at 181; NG-CP-2, at 1).

Having approved the Company's proposed low-income PIM, we find it unnecessary at this time to approve any of the alternative PIMs offered by several of the intervenors. The Department acknowledges and appreciates the time and effort dedicated to these proposals, particularly from the various industry consultants retained by the intervenors. We recognize that most of the alternative PIMs were intended for full development in a separate proceeding, as some proposals lack specific targets or deadbands or additional information supporting their parameters, and we find that MEDA's proposal raises concerns about the collection of potentially sensitive data that would require further consideration beyond the instant proceeding (Exhs. AG-WG-1, at 33-34, 39; EDF-CLF-JRC-1, at 58-61; MEDA 1.0, at 50; Acadia Center Brief at 20). If the Department determines that a future stakeholder proceeding to evaluate PIMs is appropriate, we may revisit these alternative proposals.

c. <u>First Call Resolution PIM and Digital Customer Engagement PIM</u>

The Company proposes two PIMs that focus on customer service – one aimed at resolving customer inquiries during a customer's initial call and one to expand customers' choices of digital self-service tools (Exh. NG-CPIP-1, at 189-190, 193-195). The Attorney General, CLF, EDF, and Acadia Center argue that these PIMs fail to satisfy the Department's standard for approval (Attorney General Brief at 36-37; Attorney General Reply Brief at 9; CLF Brief at 21; EDF Brief at 21-23; Acadia Center Brief at 18; CLF, EDF, and Acadia Center Reply Brief at 6).

As part of their public service obligation, distribution companies are responsible for providing low-cost and reliable service to customers. D.P.U. 95-118, at 47; D.P.U. 94-158, at 3; The Berkshire Gas Company, D.P.U. 92-210, at 32 (1993). In fulfilling this obligation, the Department expects companies to satisfy SQ expectations in the course of their day-to-day business operations. D.P.U. 12-120-D. The Department finds that the customer interactive elements of the proposed first call resolution PIM and digital customer engagement PIM are substantially encompassed within the Company's public service obligation. Therefore, the Department finds that it is not appropriate for the Company to receive a performance incentive related to these activities, and we reject the Company's proposed PIMs.

During the proceeding, the Company noted it would not be opposed to converting some of its proposed PIMs to scorecard metrics (Exh. NG-PIMS-Rebuttal-1, at 68-70; Tr. 6, at 867, 898). The Department finds that it would be useful for the Company to track and report on these two proposed PIMs as scorecard metrics. Accordingly, the Department directs the Company to include in its annual reporting of its proposed scorecard metrics the results from its first call resolution and digital customer engagement activities.

d. Fleet Electrification PIM

National Grid proposes a PIM that would measure the Company's performance in transitioning its light-duty fleet to EVs (Exh. NG-CPIP-1, at 183-184, 186). Over the course of the PBR-O term, National Grid plans to accelerate its acquisition of EVs at a pace that the Company expects will allow it to ensure its infrastructure and logistics will be ready to support a fully electrified fleet by 2030 (Exhs. NG-CPIP-1, at 185; DPU 49-7). The Attorney General, DOER, CLF, EDF, and Acadia Center assert that the Department should reject the Company's fleet electrification PIM (Attorney General Brief at 35; Attorney General Reply Brief at 11; DOER Brief at 56, citing Exh. EDF-CLF-JCR-1, at 45; CLF Brief at 20; EDF Brief at 21; Acadia Center Brief at 18; CLF, EDF, and Acadia Center Reply Brief at 6).

The Department recognizes that transitioning from internal combustion vehicles to EVs improves air quality by reducing GHG emissions and thereby advances the Commonwealth's public policy goal of reaching net zero emissions by 2050. In this regard, National Grid plc has an organization-wide goal of achieving a 100-percent electric light-duty fleet by 2030, and this goal is applicable to MECo and Nantucket Electric (Exhs. EDF-CLF-JRC-1, at 45-46 & n.83; DOER 3-16). While the Department acknowledges the efforts taken by National Grid to electrify its light-duty fleet during the PBR-O term, we find that it is inappropriate to allow an incentive to achieve an objective that the Company already is committed to achieving by corporate mandate. Thus, irrespective of whether the Company's proposed PIM meets the Department's standard for approval, we conclude that the proposed fleet electrification PIM is not in the best interest of ratepayers. Accordingly, we reject the Company's proposed fleet electrification PIM. The Department, however, finds it is useful to track the Company's progress toward meeting the organizational goal of 100-percent electric light-duty fleet by 2030. As such, the Company shall report on its efforts annually as part of its scorecard metrics reporting.

e. DER Interconnection PIM

National Grid proposes a DER interconnection PIM to track the success of the Company's efforts to increase the capacity of DER interconnected on its distribution system (Exh. NG-CPIP-1, at 199). The Attorney General, CLF, EDF, and Acadia Center argue that the proposed PIM should be rejected or modified (Attorney General Brief at 37-38; CLF Brief at 22; EDF Brief at 24-27; Acadia Center Brief at 19-20; CLF, EDF, and Acadia Center Reply Brief at 5-6, 8-9).

As an initial matter, and similar to our findings above regarding the Company's proposed low-income discount PIM, the Company's proposed DER interconnection PIM incorporates symmetrical deadbands around a target level of MW of DER interconnected to the distribution system each year (Exhs. NG-CPIP-1, at 179-180; NG-CPIP-7, at 7). The Company earns an incentive for each MW of DER interconnected above the upper deadband, and the Company incurs a penalty for each MW of DER that was not interconnected below the lower deadband (Exhs. NG-CPIP-1, at 179-180; NG-CPIP-7, at 7). The Department finds the Company's proposed PIM structure is acceptable.

The Department finds that increasing the capacity of interconnected DER advances a specific public policy goal, as increased DER deployment is a key strategy to reducing emissions (Exhs. NG-CPIP-1, at 204; NG-PIMS-Rebuttal-1, at 65; AG 6-12). Further, the proposed PIM incentivizes the Company to prioritize and innovate to establish a faster pace of interconnection, (Exhs. NG-CPIP-1, at 205; NG-PIMS-Rebuttal-1, at 65-66). The Department previously established a DG interconnection time frame enforcement metric, which requires each EDC to annually report aggregate average time measured in business days necessary to execute and issue an executable interconnection service agreement (or the functional equivalent) from the date an application is received compared to the aggregate number of business days allowed by the Standards for Interconnection of Distributed Generation (Exh. NG-CPIP-1, at 200). The time frame enforcement metric enforces the EDCs' public service obligations to provide interconnection service, whereas the proposed DER interconnection PIM measures the impacts of improvements to the interconnection process (Exhs. AG 6-13; AG 6-23). These process improvements are beyond the Company's obligation of processing interconnection applications, and the proposed PIM is intended to measure the impacts of these improvements (Exh. NG-PIMS-Rebuttal-1, at 64, 66). Based on these considerations, we conclude that, in this instance, the activities measured by the proposed PIM are not within the Company's public service obligations.

As noted, the Attorney General, CLF, EDF, and Acadia Center argue that the proposal fails to satisfy the Department's third design guideline (Attorney General Brief at 37; CLF Brief at 22; EDF Brief at 24; CLF, EDF, and Acadia Center Reply Brief at 6). The Department recognizes that significant factors influence the Company's ability to interconnect MWs of DER to its system, including interest rates, market forces, and supply chain costs (Exh. AG-WG-1, at 38-39). Nevertheless, the Company plans on taking several well-defined actions to further the integration of DER onto its electric distribution system, including comprehensively improving its interconnection process, automating its application portal, collaboratively and proactively managing key stakeholder accounts, and increasing customer outreach (Exhs. DPU 35-10;

AG 6-13). These actions are intended to improve the interconnection process in a comprehensive manner, which will speed the rate of interconnection in the face of external factors such as increased saturation (Tr. 6, at 850-853). Further, the structure of the proposed PIM, with a target based on recent historical data, a deadband to absorb an amount of variation, and a roll-over mechanism, should adequately account for variations caused by external factors (Exh. EDF-CLF 1-23). Based on these considerations, we conclude that the proposed PIM is available for activities where National Grid plays a distinct and clear role in bringing about the desired outcome of increasing the pace of DER interconnections to the Company's system.

The Attorney General also argues that the proposed PIM creates a perverse incentive to overspend, in violation of the Department's fifth design guideline (Attorney General Brief at 37-38). We disagree. As noted above, the Company has identified well-defined actions that it expects to take to meet the proposed PIM's target (Exhs. DPU 35-10; AG 6-13). We expect National Grid to undertake these activities in a reasonable manner, and we note that final cost recovery is subject to a prudency review. Further, the symmetrical design of the PIM is simple and creates a balanced incentive structure that ensures that only exceptional performance is rewarded and that the Company will be accountable if it underperforms (Exh. NG-PIMS-Rebuttal-1, at 67). Based on these considerations, we are satisfied that the proposed PIM does not create any perverse incentive to overspend.

The Department has reviewed the Company's proposed DER interconnection PIM and finds that it meets the remaining design guidelines. D.P.U. 18-150, at 121-122. The Department, however, is not persuaded that the proposed target performance level is appropriate, as we conclude it may not result in fully incentivizing the Company to accelerate the pace of

DER interconnection. Specifically, National Grid states that it set the target level of 175 MW, the lower deadband of 140 MW, and the upper deadband of 210 MW, to align with the Company's five-year historical average of 206 MW of DER interconnected (Exhs. NG-PIMS-Rebuttal-1, at 68; DPU 22-12; DPU 35-11). That historical average, however, aligns with the upper deadband, not the proposed target level. Thus, the proposed PIM would result in the Company earning an incentive for performance once it simply exceeds the historical average. National Grid states that its proposed target level is appropriate, as it accounts for the impacts of DER interconnection saturation, which the Company submits will drive performance downward (Exhs. DPU 22-12; DPU 35-11). In particular, the Company cites a 33-percent decline from its 2022 to 2023 performance due to saturation (Exhs. NG-PIMS-Rebuttal-1, at 68; DPU 22-12).

The Department acknowledges that DER interconnection saturation has been straining the interconnection process for several years. In response, the Company has proposed several capital investment projects to create more DER interconnection hosting capacity, which are pending review (Tr. 6, at 853-854, 856). Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-12 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-09 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-06 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-170 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-61 (pending). The proposed projects are based on interconnection queues in saturated areas that were identified prior to the establishment in 2021 of the program authorizing the Company to propose its capital investment projects. Provisional System

Planning Program, D.P.U. 20-75-B at 26, 35 (2021). As such, National Grid's historical period used to set the target level for the proposed PIM contains multiple years of interconnection data in the face of increasing saturation, including 2022, which was the Company's best performance in the five-year data set (Exh. NG-CPIP-7, at 11).

Based on these considerations, the Department finds that it is reasonable and appropriate to align the proposed PIM's target with the Company's five-year historical average of performance. The Department therefore approves the DER interconnection PIM, but with two modifications. First, the target performance level shall be set at 210 MW, with a symmetrical 20-percent upper and lower deadband around the target. Second, the proposed maximum incentive and penalty levels shall be adjusted to remain a symmetrical 125 MW above and below the target level. Additionally, the incentive and penalty amounts shall remain the same at $16,667 per MW of DER interconnected. In any year where the Company interconnects MWs of DER above the maximum incentive threshold or below the maximum penalty threshold, the remaining MWs of DER beyond the cap shall be rolled over into the next year.

The Company shall report on its PIM performance and associated calculations in its annual PBR-O rate adjustment filing, to be submitted by June 15 of each year. The DER interconnection PIM report shall include a summary of the Company's prior-calendar year performance, including the level of performance achieved, calculations for incentives earned or penalties incurred, and an explanation if the target level was not achieved (Exh. NG-CPIP-1, at 175).

f. Other Issues

The Department has reviewed the alternative PIMs proposed by the Attorney General, by Acadia Center on its own, and by CLF, EDF and Acadia Center jointly (Exhs. AG-WG-1, at 39-40; EDF-CLF-JRC-1, at 62-65; EDF-CLF-JRC-Surrebuttal-1, at 14-15; Acadia Center Brief at 20). As these intervenors acknowledge that their proposals are intended for full development in a separate proceeding, given their lack of specific targets or deadbands or additional information supporting their parameters, the Department will not evaluate them further in this proceeding (Exhs. AG-WG-1, at 39-40; EDF-CLF-JRC-1, at 64; Acadia Center Brief at 20). The Department appreciates these proposals and recognizes the benefits of intervenor ideas for PIMs. If the Department determines that a future stakeholder proceeding to evaluate PIMs is appropriate, we may revisit these proposals.

H. Scorecard Metrics

1. Introduction

National Grid proposes four scorecard metrics for reporting purposes only to measure: (1) customer satisfaction through survey; (2) outage communication; (3) the Company's GHG emissions reduction efforts; and (4) the percentage of customers participating in the Company's DER Programs (Exh. NG-CPIP-1, at 206-207). The Company proposes to report on its proposed scorecard metrics in conjunction with its PIM reporting, as part of the annual PBR-O rate adjustment filings submitted no later than June 15 each year, beginning in 2025 and through the term of the PBR-O plan (Exh. NG-CPIP-1, at 205).

2. Company Proposal

a. Customer Satisfaction Survey

National Grid proposes to use two surveys to measure customer satisfaction: (1) a non-contact survey based on a random sample of customers; and (2) a contact survey based on a sample of customers who had contacted the Company within the last 30 days (Exh. NG-CPIP-1, at 208-209). According to National Grid, the non-contact survey will ask customers to rate their satisfaction with the service that they received from the Company, excluding price, on a scale of one to seven, where one means “very dissatisfied” and seven means “very satisfied” (Exh. NG-CPIP-1, at 209). National Grid proposes for the non-contact survey to ask customers to provide two ratings: (1) on a scale of one to seven, how courteous was the Company’s customer service department, where one means “not at all courteous” and seven means “very courteous;” and (2) on a scale of one to seven, how well did the Company’s customer service department respond to the call, where one means “not at all responsive” and seven means “very responsive” (Exh. NG-CPIP-1, at 209). The Company proposes to provide the results from these surveys as the scorecard metric (Exh. NG-CPIP-1, at 209).

b. Outage Communication

National Grid proposes to survey its customers who recently experienced an outage, including during emergency events, to gauge their level of satisfaction with the Company’s level of communication related to the outage (Exh. NG-CPIP-1, at 209-210). The Company proposes for the survey to be based on a ten-point scale, with a score of one for “very dissatisfied” and score of ten for “very satisfied” (Exh. NG-CPIP-1, at 209). The proposed scorecard metric would provide the percentage of customers who selected a score of eight, nine, or ten

(Exh. NG-CPIP-1, at 209). National Grid states that it would use the survey results to better understand the effectiveness of the Company's communications, and to develop opportunities to improve the customer experience (Exh. NG-CPIP-1, at 210).

c. Greenhouse Gas Emissions Reductions

National Grid proposes a GHG emissions reduction scorecard metric to measure the avoided metric tons of carbon emissions or equivalent from the Company's electric distribution operations, property, and transportation fleet (Exh. NG-CPIP-1, at 207). National Grid states that the proposed scorecard metric supports the Company's effort to reduce GHG emissions in alignment with Company's and Commonwealth's goal to achieve net zero GHG emissions by 2050 (Exh. NG-CPIP-1, at 207-208).

d. DER Program Participation

National Grid proposes a scorecard metric to track the number of customers enrolled in any DER program, or who use DER outside of a formal DER program and are otherwise known to the Company (Exh. NG-CPIP-1, at 210). The Company states that this proposed metric would track customers who have any net metering or Solar Massachusetts Renewable Target ("SMART") facility; who have enrolled in receiving credits from any net metering or SMART community solar or alternative on-bill credit facilities; who have installed solar; energy storage systems; or who use other DER onsite, such as battery storage systems, but are not enrolled in net metering or SMART (Exh. NG-CPIP-1, at 210). The Company proposes to include an itemization of residential customers in these programs or with such devices that are enrolled in Rate R-2 or live in an environmental justice population, as defined by the Commonwealth (Exh. NG-CPIP-1, at 211). The Company notes that unlike the DER interconnection PIM that measures the MW of DER interconnected to the distribution system, the proposed scorecard metric tracks the number of customers receiving direct benefits from the available DER incentive programs (Exh. NG-CPIP-1, at 211).

3. Positions of the Parties

a. Intervenors

On brief, the Attorney General does not specifically address the proposed scorecard metrics but, consistent with her position on the proposed PBR-O, IPIMs, and PIMs, she asserts that the scorecard metrics should be rejected (Attorney General Brief at 40). DOER also does not address any specific scorecard metrics but argues that performance metrics, and presumably scorecard metrics, require broad stakeholder participation and should be addressed in a comprehensive manner during a separate phase of the ESMP proceedings (DOER Brief at 56-61; DOER Reply Brief at 6-7). No other intervenor commented on the Company's proposed scorecard metrics.

b. Company

National Grid argues that its scorecard metrics are designed to enable tracking and transparency of the Company's performance in additional areas beyond the proposed IPIMs and PIMs, and they will allow the Department to evaluate the Company's efforts and progress in defined areas of interest that directly impact or benefit customers (Company Brief at 228-229). National Grid maintains that the scorecard metrics are reporting-only metrics, with no associated incentives or penalties, and do not have any bearing on the Company's revenue requirement or additional performance incentives or penalties that may be earned (Company Brief at 229). The

Company asserts that its scorecard metrics should be approved as an integral component of the overall CPI Plan (Company Brief at 236).

4. Analysis and Findings

As discussed above, the Department has approved a PBR-O plan for the Company, along with two PIMs. The Department also rejected several PIMs and directed the Company to track certain information as scorecard metrics. In addition to the decisions above, and to measure the range of benefits that will accrue under the PBR-O plan, the Department finds that it is appropriate to establish additional reporting-only scorecard metrics that are tied to the goals of the PBR-O plan and are consistent with the Department's regulatory objectives.

The Department has reviewed the Company's proposed scorecard metrics and the supporting record (Exhs. NG-CPIP-1, at 205-211; DPU 22-14 through DPU 22-19; DPU 33-7; DPU 36-14; DPU 49-12; AG 4-44; AG 6-22; AG 6-24). With respect to the customer satisfaction survey metric, we find that it also should include in its annual scorecard metrics reporting the Company's J.D. Power Residential Customer Satisfaction annual ranking for the primary six factors of: (1) power quality and reliability; (2) price; (3) billing and payment; (4) communications; (5) corporate citizenship; and (6) customer care (Exh. DPU 36-14). The Department recognizes that this ranking is combined with the Company's New York affiliates (Exh. DPU 36-14). Nevertheless, the Department finds there is value in customer satisfaction reporting from an independent source, such as J.D. Power. D.P.U. 22-22, at 116. Further, we direct National Grid to develop options for customers who speak languages other than English and limited English proficient speakers to respond to the customer satisfaction survey, and to report on these efforts in the first annual PBR-O adjustment filing.[43] With these modifications, the Department approves the customer satisfaction survey scorecard metric. We also approve the Company's outage communication, GHG emissions reduction, and DER participation program scorecard metrics, as proposed.

The Department previously found a low-income terminations metric is reasonable, reflective of important policy goals, and capable of reporting data in a way that promotes transparency. D.P.U. 23-80/D.P.U. 23-81, at 83-84; D.P.U. 22-22, at 125-126. Therefore, in this proceeding, we direct the Company to include a low-income terminations metric for reporting purposes only. The metric shall include low-income customer service terminations by month, and shall also include percent and number of low-income customers by census tract for each of the following: (1) service terminations for non-payment; and (2) accounts with past due balances at levels eligible for disconnect. The Department anticipates that this metric will provide insight into the year-round overall financial situation of low-income customers, including during the winter shut-off moratorium.

43 In selecting languages other than English, the Company shall be guided by the Department's Language Access Plan, which can be found at the following website: https://mass.gov/doc/september-17-2024-dpu-language-access-plan-english/download, the Department's decisions in D.P.U. 21-50, and the Massachusetts Office of Environmental Justice and Equity "languages spoken" map, which can be found at the following website: https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts.

V. RATE BASE

A. Introduction

The Company's test-year rate base was $3,002,955,189, based on a total utility plant in service of $6,013,521,425 (Exh. NG-RRP-2, Sch. 11, at 1 (Rev. 4)). To this amount, the Company proposes a normalizing adjustment of negative $63,531,565 and a known and measurable adjustment of $220,581,880 for a total proposed rate base of $3,160,005,504 (Exh. NG-RRP-2, Sch. 11, at 1 (Rev. 4)). The Company's total proposed rate base consists of a utility plant in service balance of $6,002,768,031 (Exh. NG-RRP-2, Sch. 11, at 1 (Rev. 4)). National Grid reduced its utility plant in service by the following amounts: (1) $563,916,501 in accumulated deferred income taxes ("ADIT"); (2) $272,042,757 in FAS 109 regulatory asset; (3) $2,076,462,834 for depreciation; (4) $15,972,246 for customer advances; and (5) $13,905,579 for customer deposits (Exh. NG-RRP-2, Sch. 11, at 1 (Rev. 4)). Finally, the Company added $34,038,774 in materials and supplies and $65,498,615 in cash working capital ("CWC") (Exh. NG-RRP-2, Sch. 11, at 1 (Rev. 4)).

B. Plant Additions

1. Introduction

National Grid has grouped its plant in service additions into four categories: (1) specific projects; (2) specific projects grouped as part of a National Grid U.S. Sanctioning Committee paper[44]; (3) blanket projects; and (4) program and other annual projects (Exhs. NG-BJM-1, at 8;

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[44] As of November 2021, the National Grid U.S. Sanctioning Committee was discontinued and the National Grid Executive Sanctioning Committee was established based on jurisdiction; thus, for the Company, the National Grid New England Executive Sanctioning Committee reviews and approves investments greater than $50 million up to

NG-BJM-2). A "specific project" is one that is approved for the total cost of a defined body of work and, when the work is completed, the project is closed (Exh. NG-BJM-1, at 10). A specific project may have one or more work orders associated with the project and those work orders may be at different stages of progress at any given point in time (Exh. NG-BJM-1, at 10). A "blanket project" is a project that has been set up to collect high volume, smaller dollar work order, for less than $100,000 within a given budget classification (Exh. NG-BJM-1, at 12). A "program" is a funding project that contains work orders for similar types of construction following a specific strategy (Exh. NG-BJM-1, at 12). Between January 1, 2020 and March 31, 2023, the Company identified 974 specific individual projects, 42 U.S. Sanctioning Committee specific grouped projects, 65 blanket projects, and 35 program projects (Exhs. NG-BJM-1, at 7; NG-BJM-3). During the post-test-year period April 1, 2023 through December 31, 2023, the Company identified 1,117 specific individual projects, 46 U.S. Sanctioning Committee specific grouped projects, 65 blanket projects, and 36 program projects (Exhs. NG-BJM-1, at 19; NG-BJM-3 (Supp.)).

2. Project Documentation

National Grid utilizes a detailed capital planning and approval process to determine the investments needed to maintain a safe and reliable electric distribution system within the planning period; to obtain the appropriate level of approval for the investments; and to ensure controls are in place to manage the scope, timing, and costs of the investment (Exhs. NG-BJM-1,

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$203 million (Exh. AG 8-3, at 1). Investments greater than $203 million are reviewed and endorsed by the National Grid New England Executive Sanctioning Committee, and then the investment proceeds to the National Grid United Kingdom Group Investment Committee for review and approval (Exh. AG 8-3, at 1).

at 21; NG-CPIP-1, at 63-69). For each capital project, the Company has provided detailed information and supporting documentation on the costs, including project cover sheets, approved amounts, actual costs, cost variance information, project sanction papers, re-sanction papers, and closure papers (Exhs. NG-BJM-1, at 9; NG-BJM-2; NG-BJM-3; NG-BJM-3 (Supp.); NG-BJM-3A (Supp.); NG-BJM-4; NG-BJM-6; NG-BJM-6 (Supp.); NG-BJM-6A; NG-BJM-6A (Supp.); NG-BJM-7; NG-BJM-7 (Supp.); NG-BJM-8; NG-BJM-8 (Supp)).

For specific projects in the filing with more than $50,000 of asset additions or a reduction of assets of more than $25,000, the Company has provided project summary sheets (Exhs. NG-BJM-1, at 10; NG-BJM-6). Project summary sheets include information such as project numbers, project descriptions, project approved amounts, total to date project spending, project status, approval history, in-service additions and cost of removal amount (Exhs. NG-BJM-1, at 10; NG-BJM-6). The Company also provided documentation for projects grouped as part of a U.S. Sanctioning Committee paper to illustrate project variance explanations and re-authorizations based on the total approved amount for the group of funding projects (Exhs. NG-BJM-1, at 11; NG-BJM-6A).

Blanket projects are budgeted and approved annually on a fiscal year basis and a variance analysis comparing approved spending and actual spending is performed on the current fiscal year (Exh. NG-BJM-1, at 12). The Company has provided documentation for each blanket project including blanket project summary sheets, retirement reports, work order asset detail reports, direct/indirect reports, project cost summaries, and summary closure reports (Exhs. NG-BJM-1, at 11-12; NG-BJM-7).

Like blanket projects, spending for a program project is managed more as a whole and individual programs can sometimes be modulated to offset over-spending or under-spending in other program or capital plan areas (Exh. NG-BJM-1, at 13). Programs are budgeted and approved annually, and a variance analysis is performed on the current fiscal year only if the program exceeds its approved annual budgeted amount (Exh. NG-BJM-1, at 13). Similar to blanket projects, the Company has included supporting documentation for program funding projects that includes project cover sheets, approved amounts, actual costs, cost variance information, project sanctioning reports, re-sanctioning reports, and closure papers (Exhs. NG-BJM-1, at 12; NG-BJM-8).

Additionally, the Company has provided documentation supporting its post-test-year capital additions placed in service from April 1, 2023 through December 31, 2023 (Exhs. NG-BJM-1, at 19; NG-BJM-3 (Supp.); NG-BJM-3A (Supp.); NG-BJM-6 (Supp.); NG-BJM-6A (Supp.); NG-BJM-7 (Supp.); NG-BJM-8 (Supp.)). The Company states that it has provided all documentation supporting its post-test-year additions during the discovery period in this proceeding and the nature of the post-test-year project documentation is no different than the project documentation provided for capital additions in service prior to and during the test year (Exh. NG-BJM-1, at 17-18).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should deny recovery for the following capital additions: (1) Lynn substation replacement; (2) recloser replacement programs; (3) Hendersonville substation; (4) Revere to Winthrop underground cable replacement;

(5) Melrose substation replacement; and (6) Gloucester substation replacement (Attorney General Brief at 46). The Attorney General claims that the Company's capital project review process is insufficient and its justifications for each project amount to conclusory statements (Attorney General Brief at 46).

The Attorney General specifically points to the Lynn substation replacement project to demonstrate deficiencies in the Company's capital approval process, which she claims is common to all six projects (Attorney General Brief at 48). According to the Attorney General, the weighing of alternative and less expensive options was subjective and lacked quantifiable risk, which does not meet the standard of prudent investment (Attorney General Brief at 48). The Attorney General contends that project justifications were inconsistent, and the review process was reliant on subjective, non-reviewable assessments, and an incomplete comparison of alternatives (Attorney General Brief at 48, 52).

The Attorney General argues that the project sanctioning paper for the Lynn substation replacement only partially compares the merits of replacement of the entire substation to only certain components (Attorney General Brief at 48). The Attorney General maintains that the Company picked a more expensive "metal clad option" due to ease of construction, despite testifying that "the least cost option moves forward" (Attorney General Brief at 9, citing Tr. 11, at 1421-1422). The Attorney General also takes issue with the Company's use of a risk score to prioritize projects and asserts said risk scores are not reflective of project costs (Attorney General Brief at 49, citing Tr. 8, at 1135).

The Attorney General concludes that each project she recommends for disallowance suffers from the same inadequacies of the Company's capital approval process as the Lynn substation replacement (Attorney General Brief at 52). The Attorney General asserts that the Company has not carried its burden in justifying the six projects as prudent investments and recommends their inclusion in rate base be disallowed (Attorney General Brief at 52).

b. Company

i. Introduction

National Grid maintains that the project documentation provided in this proceeding comprises the necessary documentation to facilitate the Department's review of plant additions put into service since the Company's last base distribution rate case through December 31, 2023 (Company Brief at 375-378, 379, citing Exhs. NG-BJM-1, at 18; NG-BJM-3 (Supp.); NG-BJM-3A (Supp.); NG-BJM-6 (Supp.); NG-BJM-6A (Supp.); NG-BJM-7 (Supp.); NG-BJM-8 (Supp.)). In addition, National Grid asserts that it provided a detailed explanation of its planning and capital budgeting processes as well as the authorization and control of capital spending (Company Brief at 374-375). Therefore, the Company argues that it has demonstrated that its capital additions placed in service and closed to plant by the end of 2023 were prudently incurred and used and useful in providing service to customers, and the Department should approve the capital additions for inclusion in rate base (Company Brief at 376-377, 378, 382).

National Grid argues that the Attorney General's recommendations to disallow what the Company claims is $124.2 million in capital additions are baseless (Company Brief at 382). National Grid contends that it has demonstrated that the projects in question are in service, used and useful, and resulted from a reasonable, good faith process factoring in considerations regarding safety, reliability, and asset condition (Company Brief at 382, citing Exhs. NG-BJM/EP-Rebuttal-1, at 10-39; NG-BJM/EP-Rebuttal-2). National Grid claims that the

Attorney General's recommendation to disallow these costs is based on an endorsement of an unprecedented shift to analyze capital projects through a benefit-cost analysis (Company Brief at 383, citing Attorney General Brief at 44, 47). The Company addressed each project recommended for disallowance (Company Brief at 383).

ii. Lynn Substation Replacement

The Company argues that the Lynn substation replacement project has met the applicable standard for inclusion into rate base (Company Brief at 383, citing Exhs. NG-BJM/EP-Rebuttal-1, at 15-19; NG-BJM/EP-Rebuttal-2; AG 8-4; AG 8-4, Att.; NG-BJM-6A, at 149-265; Tr. 8, at 1114-56, 1167-1179). National Grid contends that it demonstrated that the investment in the Lynn substation was prudently incurred, following a project authorization process that factored safety, reliability, and asset condition benefits that resulted in used and useful plant for customers (Company Brief at 383). The Company points out that the Lynn substation was built in 1920, when there were no Occupational Safety and Health Administration ("OSHA") requirements, and has a history of operational issues, outages, and a lack of replaceable components (Company Brief at 383-384, citing Exh. AG 8-4 & Att.). The Company argues that there is no basis to deny the costs associated with the Lynn substation replacement project considering that a substation rebuild was justifiable for several reasons (Company Brief at 385-386).

iii. Recloser Replacement Programs

The Company argues that costs for the recloser replacement programs should be included in rate base (Company Brief at 396). The Company notes that the Attorney General is recommending disallowance of two separate recloser programs, the Viper recloser replacement program and the Form 3 recloser replacement program (Company Brief at 394).

The Company claims it is replacing the Viper reclosers due to a manufacturing defect (Company Brief at 396, citing Exhs. NG-BJM/EP-Rebuttal-1, at 34; AG 17-8). National Grid maintains that there was a safety risk in keeping these reclosers in service and, therefore, the Company followed its duty to provide safe and reliable service (Company Brief at 396, citing Exh. AG 8-6). Regarding the Form 3 recloser replacement program, the Company contends that the replacement of these reclosers provided additional functionality that could result in shorter outage durations, which is consistent with modern distribution system considerations (Company Brief at 398). National Grid asserts that the Department has been aware of this program since 2018 and approved recovery of costs associated with the program in D.P.U. 18-150, and the Company contends that it was reasonable to continue implementing the program (Company Brief at 398 citing Exh. NG-BJM/EP-Rebuttal-1, at 37). The Company also argues that it has provided the necessary project documentation to support the recloser replacement programs (Company Brief at 399). Therefore, National Grid argues that there is no basis to deny the $5.4 million in costs associated with the recloser replacement programs (Company Brief at 399).

iv. Hendersonville Substation

The Company argues that the Hendersonville substation project should be included in rate base (Company Brief at 386). National Grid asserts that it provided project documentation for this project, including project descriptions and sanction papers (Company Brief at 386, citing Exhs. NG-BJM-6A at 1709; AG 8-13 & Att. (Supp.)). The Company maintains that construction of a new substation was warranted because a one-for-one replacement of individual components would not have addressed the other issues identified through the Company's comprehensive plan to replace the Hendersonville substation, such as future load growth (Company Brief at 387, citing Exh. NG-BJM/EP-Rebuttal-1, at 20). The Company argues that it has fully supported its project costs and that there is no basis to deny the costs associated with the Hendersonville substation project (Company Brief at 389).

v. Revere-Winthrop Underground Cable Replacement

The Company argues that the Revere to Winthrop 23 kV underground cable replacement project should be included in rate base (Company Brief at 391). The Company offers several explanations for the increased costs associated with this project: (1) the original project estimate was purely conceptual and did not reflect detailed engineering analysis; (2) changes in project scope due to the need to remove abandoned facilities instead of just abandoning them as initially planned; (3) significant contractor cost increases that came during the period of rampant inflation in the marketplace; (4) traffic problems caused by construction, including the need to move construction to night time; and (5) severe underground obstructions that delayed construction (Company Brief at 392). The Company maintains that it knew about these increased costs before moving forward with the project and that they were not the result of any mismanagement or inadequate capital spending governance (Company Brief at 393, citing Exh. AG-WG-1, at 80). The Company contends that it provided relevant documentation including a project description and a sanction paper supporting the decision to move forward with the project as well as an explanation for why the existing asset failed to meet current industry standards (Company Brief at 393, citing Exhs. NG-BJM-6, at 222; NG-BJM/EP-Rebuttal-1, at 30; AG 8-21). The

Company argues that there is no basis to deny the costs associated with the 23 kV underground cable replacement project between Revere and Winthrop (Company Brief at 394).

vi. Melrose Substation Replacement

The Company argues that the Melrose substation replacement project should be included in rate base (Company Brief at 394). The Company maintains that decommissioning of the Melrose substation was driven by asset condition issues and was consistent with the Company's strategy to replace indoor substations with outdoor substations to address safety concerns associated with indoor substations (Company Brief at 394, citing Exhs. AG 8-15; NG-BJM-6A, at 64). The Company explains that the specific safety issues included excess stress on cables and arc flash incident energy concerns, and National Grid cites reliability as a secondary driver after safety (Company Brief at 394, citing Exh. NG-BJM-6A, at 64-65). National Grid contends that, similar to its Lynn and Gloucester substation projects, the Company does not wait for failure or injury to address safety concerns (Company Brief at 394-395). The Company claims it provided project documentation for the Melrose substation project, including a project description, sanctioning papers, and additional details regarding the project asset conditions, that supports the Company's decision to move forward with the project (Company Brief at 395, citing Exhs. NG-BJM-6A, at 1540; NG-BJM/EP-Rebuttal-1, at 32; AG 8-15). The Company argues that the Attorney General's recommendation for disallowance is based on fundamental mischaracterization of the Company's processes and that there is no basis to deny the costs associated with the Melrose substation decommissioning project (Company Brief at 396).

vii. Gloucester Substation Replacement

The Company argues that the Gloucester substation replacement project should be included in rate base (Company Brief at 389). The Company contends that it provided a project description and sanctioning papers as well as additional details regarding the project asset conditions (Company Brief at 389, citing Exhs. NG-BJM-6A, at 1399; AG 8-11 & Att.). The Company maintains that the Attorney General's recommendation to deny costs associated with the Gloucester substation is based on a mischaracterization of the Company's asset condition assessment process, dismissal of the provided project documentation, unsubstantiated assumptions about the cost alternatives, and an improper application of a cost-effectiveness test (Company Brief at 389-390, citing Exhs. NG-BJM-6A, at 1400-1407; NG-BJM/EP-Rebuttal-1, at 25; AG 8-11, Att.). Regarding its asset condition assessment process, the Company argues that its public service obligation requires it to proactively address known asset condition issues instead of waiting for complex issues to compromise reliability, especially where solutions are large and complex and project lead time is substantial (Company Brief at 390). According to the Company, waiting for equipment to fail would result in a damage/failure project that is typically executed in a short, emergency timeframe without the benefit of consideration of alternatives because the investment must be made quickly to restore functionality (Company Brief at 390). Further, the Company contends that it bases capacity considerations on forecasts and credible information from customers, not on speculation (Company Brief at 391). National Grid claims that it identified that the cost difference between a 4 kV and 15 kV rated metal clad switchgear was insignificant and that the decision to proceed with 15 kV rated equipment had the secondary driver of providing flexibility for future conversion, should the need arise, but that the decision was not based on speculative assessment of future load growth (Company Brief at 391). Accordingly, the Company argues that there is no basis to deny the costs associated with the upgrade to the Gloucester Substation (Company Brief at 391).

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, 390 Mass. 208, 229-230. A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known, or reasonably should have been known, at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (1993); D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. D.P.U. 95-118, at 39-40; 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; D.P.U. 92-210, at 24; 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

a. Specific Projects

The Attorney General argues that costs associated with the Lynn substation replacement, the recloser replacement programs, the Hendersonville substation, the Revere to Winthrop underground cable replacement, the Melrose substation replacement, and the Gloucester substation replacement should be disallowed on the grounds that the Company's project review process is insufficient (Attorney General Brief at 46). We address each project below.

i. Lynn Substation Replacement

The Company's Lynn substation was built in 1920, when there were no OSHA requirements (Tr. 8, at 1168). Further, the Lynn substation had soil contamination and groundwater considerations impacting the project scope due to the facility's former use as a generating station with a manufactured gas plant (Tr. 8, at 1170-1171). Moreover, the Lynn substation did not have the capability of having remotely controlled equipment or even remote status monitoring equipment, which required operators to violate distance requirements to check on equipment (Tr. 8, at 1174-1175). Given the age and condition of the then-existing Lynn substation, including the range of safety and OSHA violations, such as breaker disconnects hinged on the underside of cubicles and electrical clearances in the disconnect rooms, the Department finds that the Company appropriately engaged in a sound project review process and determined that total replacement was the best solution to ensure safe and reliable service for National Grid's customers, as well as the safety of Company employees at the substation (Exhs. NG-BJM-6A, at 149-200; NG-BJM-6A, at 201-265; NG-BJM/EP-Rebuttal-1, at 15-19; NG-BJM/EP-Rebuttal-2; AG 8-4 & Att.; Tr. 8, at 1114-1156, 1167-1179).

ii. Recloser Replacement Programs

The Company replaced the Viper reclosers due to a manufacturing defect and determined that keeping these reclosers in service was a safety risk (Exhs. NG-BJM/EP-Rebuttal-1, at 34-35; AG 8-6; AG 17-8). The Department is satisfied that the Company's actions were reasonable to provide safe and reliable service to its customers (Exhs. NG-BJM/EP-Rebuttal-1, at 34-35; AG 8-6; AG 17-8). Similarly, the Department finds that the Company's Form 3 recloser replacement program was required for safe and reliable service (Exh. AG-WG-1, at 84). The Company's replacement of Cooper pole top reclosers equipped with Form 3A controls was to address multiple issues with the in service Form 3A reclosers with respect to operations, maintenance, safety, reliability, and asset condition because they had been in service for more than 25 years and were exhibiting a variety of problems, including battery charging circuit problems, battery failure, and exterior deterioration and rust, all of which caused multiple malfunctions (Exh. AG 17-9, Att., at 3). Given the reclosers were in service for more than 25 years, along with the variety of problems the Company identified, the Department finds the Company appropriately made the decision to move forward with this project (Exhs. NG-BJM/EP-Rebuttal-1, at 36-37; AG 8-7; AG 17-9).

iii. Hendersonville Substation

The Department finds that the Company appropriately identified asset conditions of the Hendersonville substation project that warranted a new substation (Exhs. NG-BJM-6A, at 1709; NG-BJM/EP-Rebuttal-1, at 19; AG 8-13; AG 8-13 (Supp.)). The Department is persuaded that the primary driver for the project was asset condition and that failure to accommodate projected load growth was a secondary project driver (Exh. AG 8-13 (Supp.)). Additionally, the Department recognizes that, given the long lead times on major capital projects, the Company cannot wait until major projects run to failure before replacement as this would result in degraded reliability for its customers (Exh. NG-BJM/EP-Rebuttal-1, at 20).

iv. Revere to Winthrop Underground Cable Replacement

The Company replaced several miles of direct-buried 23 kV underground cable between the Revere and Winthrop substations (Exh. AG 8-21, Att.). The Revere to Winthrop cables act as supply lines and directly serve only one customer (Exhs. NG-BJM/EP-Rebuttal-1, at 28; AG 8-21, at 1). Due to their redundant supply configuration, a single cable outage on one of these lines does not typically result in a reportable outage to customers, and the Company reported only one such outage during the last five years (Exhs. NG-BJM/EP-Rebuttal-1, at 28;

AG 8-21). Thus, customer outages are not indicative of the asset condition issues that justified this project (Exhs. NG-BJM/EP-Rebuttal-1, at 28).

The Department finds that the significant cost increases associated with this project were caused by legitimate factors that were largely outside of the Company's control, such as contractor construction resources, materials, and contingency costs for handling of class-D soil and groundwater, reconstruction of retaining walls, and water main replacements along the project route (Exhs. NG-BJM/EP-Rebuttal-1, at 28-29; AG 17-19; AG 47-19). The Department also notes that the asset conditions identified are consistent with the Company's underground cable replacement program, under which it has progressed multiple projects in this and prior rate cases (Exh. NG-BJM/EP-Rebuttal-1, at 30). Therefore, the Department finds that the Company appropriately made the decision to replace the 23 kV underground cable between the Revere and Winthrop substations based on asset conditions.

v. Melrose Substation Replacement

The Department finds that the Company appropriately made the decision to decommission the Melrose substation based on asset conditions and the Company's strategy to replace indoor substations with outdoor substations (Exhs. NG-BJM-6A, at 64; NG-BJM/EP-Rebuttal-1, at 31-32; AG 8-15). The specific safety issues identified for the Melrose Substation included excess stress on cables and arc flash incident energy concerns (Exhs. NG-BJM/EP-Rebuttal-1, at 32; NG-BJM-6A, at USSC-1540 - USSC-1596). Reliability was identified as a secondary driver after safety (Exhs. NG-BJM/EP-Rebuttal-1, at 28; NG-BJM-6A, at USSC-1540 - USSC-1596). Under these circumstances, the Department finds that it was appropriate for the Company to decommission the substation rather than waiting for major asset failure, especially when large projects can fail catastrophically in enclosed environments (Exhs. NG-BJM/EP-Rebuttal-1, at 32; NG-BJM-6A, at USSC-1540 - USSC-1596).

vi. Gloucester Substation Replacement

The Company rebuilt the 4 kV components of the Gloucester Substation with 15 kV equipment that will allow for a potential future conversion (Exh. NG-BJM/EP-Rebuttal-1, at 26). Given the asset conditions of the Gloucester substation, the Department finds that replacement of the substation was warranted compared to replacement of individual components of the substation (Exh. NG-BJM/EP-Rebuttal-1, at 24-25). The Department finds that, in this instance, it was appropriate for the Company to be proactive in addressing the issues at the Gloucester substation, as waiting for reliability issues would result in increasingly poor reliability as well as increased costs to customers when an asset finally fails, as the replacement project would need to be performed on an emergency basis (Exh. NG-BJM/EP-Rebuttal-1, at 25-26).

vii. Conclusion

In addition to the findings above, the Department determines that the Company has provided adequate project documentation supporting these projects (Exhs. NG-BJM/EP-Rebuttal-1, at 15-20, 24-37; NG-BJM/EP-Rebuttal-2; NG-BJM-6A, at USSC 64, 149-265, 1540-1596, 1709; AG-WG-1, at 84; AG 8-4 & Att.; AG 8-6; AG 8-7; AG 8-11; AG 8-13 & Att. (Supp.); AG 8-15; AG 8-21 & Att.; AG 17-8; AG 17-9 & Att., at 3; AG 47-19; Tr. 8, at 1114-1156, 1167-1179). We conclude that the costs associated with these projects were prudently incurred and that the projects are used and useful to ratepayers. Therefore, the Department will include these projects in the Company's plant in service.

b. Remaining Test-Year and Post-Test-Year Capital Additions

For the remaining projects, the Department finds that the Company has provided sufficient project documentation (e.g., capital construction authorization documents, revised or supplemental project authorizations, capital budget estimates, work orders, actual project cost records, the approval routing process, variance explanations, and closing reports) and additional supporting information to enable the Department to determine that the costs associated with its electric division capital projects through the end of calendar year 2023 are known and measurable, prudently incurred, and the capital additions are used and useful in providing service to customers (Exhs. NG-BJM-1, at 9; NG-BJM-2; NG-BJM-3; NG-BJM-3 (Supp.); NG-BJM-3A (Supp.); NG-BJM-4; NG-BJM-6; NG-BJM-6 (Supp.); NG-BJM-6A; NG-BJM-6A (Supp.); NG-BJM-7; NG-BJM-7 (Supp.); NG-BJM-8; NG-BJM-8 (Supp); AG 8-1 through AG 8-22; AG 13-15, AG 17-7; AG 17-8). Further, to demonstrate cost control efforts, National Grid provided information regarding its capital planning and authorization procedures, which included the Company's current capital budget input and review processes and the corresponding levels of authorization by dollar threshold, as described above (Exhs. NG-BJM-1, at 21; NG-CPIP-1, at 63-69). In addition to maintaining the documentation required by the construction authorization policy, the record shows that the Company's project supervisors review and analyze every project on a monthly basis for actual spending versus authorized spending and prepare revised or supplemental authorizations (Exhs. NG-BJM-1, at 21; NG-CPIP-1, at 63-69).

Based on our review of the Company's testimony, capital authorization processes, and capital project supporting documentation, we find that National Grid's cost control measures were reasonable and appropriate, and that costs associated with the subject capital projects were prudently incurred and the resulting plant additions are used and useful in providing service to ratepayers. Therefore, the Department will include all of the Company's capital additions placed in service between January 1, 2020 through December 31, 2023 in its plant in service.

C. Cash Working Capital Allowance

1. Introduction

The purpose of conducting a CWC lead lag study is to determine a company's "cash in-cash out" level of liquidity to provide the company an appropriate allowance for the use of its funds. Such funds are generated either internally or through short-term borrowing. 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 or for the interest expense incurred on borrowing. D.P.U. 96-50 (Phase I) at 26; Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). 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. D.P.U. 11-01/D.P.U. 11-02, at 164. In the event that the lead-lag factor is not below 45 days, a company will bear 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 CWC requirements within its control, such as the collections lag. D.P.U. 11-01/D.P.U. 11-02, at 164.

2. Company Proposal

National Grid conducted a lead-lag study to determine its CWC requirements (Exhs. NG-RRP-1, at 90; NG-RRP-3 (Rev. 4)). The Company initially calculated a CWC allowance of $67,355,764, which was revised during the proceeding to $65,498,615

(Exhs. NG-RRP-1, at 80; NG-RRP-3, at 1; NG-RRP-3, at 1 (Rev. 4); NG-RRP-7, at 8; NG-RRP-7, at 9 (Rev. 4)).

This analysis is conducted by creating a CWC percentage that is applied to the cost of service to determine a CWC allowance (Exh. NG-RRP-3, at 1 (Rev. 4)). The CWC percentage is the average number of days between incurring an expense and recovering it from ratepayers, divided by 365 (Exh. NG-RRP-1, at 91). The Company analyzed certain expense items separately for MECo and Nantucket Electric and calculated separate net lags for such expenses (Exhs. NG-RRP-3, at 2a-2b (Rev. 4); DPU 25-5; DPU 44-10).[45] The Company analyzed other items, such as O&M expense, transmission expense, and municipal taxes, on a combined basis for administrative efficiency (Exhs. NG-RRP-3, at 2a-2b, 7, 11, 12 (Rev. 4); DPU 25-5; DPU 44-10). The weighted average CWC percentage is computed by expense category and multiplied by the rate-year adjusted expense for the category and the results are summed to determine the CWC allowance (Exhs. NG-RRP-1, at 91; NG-RRP-3, at 1 (Rev. 4)).

Calculation of the Company's portion of federal and state unemployment payroll taxes and payroll withholding for incentive thrift expense yielded negative net lag amounts (Exh. NG-RRP-3, at 1 (Rev. 4)). The CWC allowance attributable to O&M expense accounts for slightly more than half of the total amount and has a calculated CWC percentage of

45 The expense categories are contract termination charges, O&M, transmission, municipal taxes, the Company's portion of federal and state unemployment insurance, Federal Insurance Contributions Act ("FICA") contributions, and the payroll withholding for the employees' amounts for federal taxes, FICA, state income taxes and incentive thrift contributions (Exh. NG-RRP-3, at 1 (Rev. 4)).

6.64 percent, which is composed of a 42.82-day revenue lag[46] less an 18.60-day expense lag, for a net lag of 24.22 days (Exh. NG-RRP-3, at 1, 3, 7 (Rev. 4)). The Company excluded amortized, hardship-protected accounts receivable balances greater than 360 days in the amount of $10,284,545 from the total operating expense in the calculation of CWC (Exhs. NG-RRP-2, Sch. 40, at 1 (Rev. 4); NG-RRP-3, at 7, 23, 41 (Rev. 4)). In addition, the Company excluded purchased power expense in the amount of $859,751,000 from the total operating expense in the CWC calculation (Exhs. NG-RRP-2, Sch. 3, at 1, 3 (Rev. 4); Sch. 44 (Rev. 4); NG-RRP-3, at 7 (Rev. 4)).

The Company calculated a CWC percentage of 6.64 percent for total O&M expense and a weighted aggregate CWC percentage of 4.90 percent[47] for all expenses (Exhs. NG-RRP-3, at 2a, 2b, 7 (Rev. 4); NG-RRP-7, at 9 (Rev. 4)). Applying the 4.90 CWC percentage to the total expenses of $1,335,566,251, the Company calculated a CWC allowance of $65,498,615 (Exhs. NG-RRP-3, at 1 (Rev. 4); NG-RRP-7, at 9 (Rev. 4)).

3. Positions of the Parties

The Company argues that in calculating its CWC allowance, it followed the approach in its last base distribution rate case, D.P.U. 18-150 (Company Brief at 267). According to the

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46 The Company uses MECo's revenue lag in analyzing O&M expenses, transmission expenses, and municipal taxes for both operating companies, as the majority of expenses are attributable to MECo and using its revenue lag has no significant impact on the CWC results (Exhs. DPU 25-5; DPU 44-10). The separate revenue lag for Nantucket Electric is 40.58 days, and when combined with MECo's revenue lag, produces a combined weighted revenue lag of 42.80 days (Exhs. NG-RRP-3, at 25 (Rev. 4); DPU 44-10).

47 The precise CWC factor is 0.0490418314710769 (Exhs. NG-RRP-7, at 9 (Excel); NG-RRP-3, at 1, 2a, 2b).

Company, that approach includes analyzing some expense items separately for MECo and Nantucket Electric and some items on a combined basis (Company Brief at 267, citing Exhs. DPU 25-5; DPU 25-10; DPU 25-11). Additionally, the Company asserts that it removed amortized, hardship-protected accounts receivable balances from the CWC calculation, consistent with the approach in D.P.U. 18-150 (Company Brief at 267, citing D.P.U. 18-150, at 164). No other party addressed the Company's proposed CWC allowance on brief.

4. Analysis and Findings

The Department has reviewed the evidence in support of National Grid's lead lag study, and we conclude that the Company has properly calculated the total revenue lag and expense lead days for both MECo and Nantucket Electric for each of the cost categories (Exhs. NG-RRP-3, at 5-22, 29-40 (Rev. 4); DPU 25-5; DPU 44-10). The Department also accepts the Company's approach to analyze some expense items separately for MECo and Nantucket Electric and some items on a combined basis (Exhs. NG-RRP-3, at 2a-2b, 7, 11, 12 (Rev. 4); DPU 44-10). We find that this approach does not materially alter the calculation of CWC allowance (Exhs. NG-RRP-3, at 2a-2b, 7, 11, 12 (Rev. 4); DPU 44-10). Finally, the record shows that the Company properly excluded amortized, hardship-protected accounts and purchased power expense from the total operating expense in the CWC calculation (Exhs. NG-RRP-2, Sch. 3, at 1, 3; Sch. 40, at 1; Sch. 44 (Rev. 4); NG-RRP-3, at 7 (Rev. 4)).

The Department accepts the Company's lead-lag study and the resulting CWC factor of 4.90 percent. Application of this CWC factor to the expenses allowed in this Order produces a CWC allowance of $66,316,302. The derivation of the CWC allowance is provided in Schedule 6 below.

D. Accumulated Deferred Income Taxes

1. Company's Proposal

National Grid proposed an ADIT balance of $563,916,501, comprising a total test-year-end ADIT balance of $598,755,920 less $18,599,803 in normalizing adjustments, and less $16,239,616 in what the Company identified as known and measurable adjustments (Exhs. NG-RRP-2, Sch. 11, at 1, 3 (Rev. 4); NG-RRP-7, at 7 (Rev. 4)). The Company's adjustments include ADIT assets associated with: (1) a FAS 109 regulatory liability tax gross-up of $74,322,081; (2) a corporate alternative minimum tax of $9,545,555; (3) net operating losses ("NOL") of $8,783,881; (4) Nantucket undersea cables of $6,763,161; (5) Grid Modernization of $2,117,031; (6) EV Phase III costs of $412; and (7) automatic meter readers of $2,946,408[48] (Exh. NG-RRP-2, Sch. 11, Excel, tab P3-ADIT Summary, Col. O (Rev. 4)). The Company's ADIT balance also incorporates: (1) a post-test-year ADIT adjustment of $4,892,897 associated with post-test year activities; (2) a reserve for uncertain tax positions associated with book versus tax timing differences of $7,127,280; and (3) CIAC-related ADIT of $57,618,932 (Exhs. NG-RRP-1, at 81; NG-RRP-2, Sch. 11, Excel, tab P3-ADIT Summary, Col. O, Cell K21 (Rev. 4)).

2. Positions of the Parties

On brief, National Grid reiterates its ADIT proposals and asserts that it calculates income tax expenses for ratemaking purposes using financial accounting taxable income and statutory

48 The ADIT assets associated with the Nantucket undersea cables, Grid Modernization, EV Phase III, and automatic meter readers are excluded from the total ADIT because the associated costs are not recovered through base distribution rates (Exh. NG-RRP-1, at 79).

tax rates, with book tax timing differences primarily due to recognizing accelerated depreciation expense for tax purposes (Company Brief at 268-269, citing Exhs. NG-RRP-1, at 81; DPU 31-1, Att.). No other party addressed the Company's ADIT proposals on brief.

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 accumulated balance of interest-free funds is available to the utility to further invest until it is then needed to fund the taxes due and payable in later years. Therefore, deferred income taxes represent an offset to rate base. D.P.U. 87-59, at 63; AT&T Communications of New England, D.P.U. 85-137, at 31 (1985); Boston Edison Company, D.P.U. 1350, at 42-43 (1983); Boston Edison Company, D.P.U. 18200, at 33-34 (1975).

First, the Department addresses the Company's proposal to include a deferred tax asset associated with corporate alternative minimum tax as a deduction from its ADIT balance included in rate base (Exhs. NG-RRP-1, at 81; NG-RRP-2, Sch. 11, at 3, Excel, tab P3-ADIT Summary (Rev. 4)). The Inflation Reduction Act of 2022, Pub. L. No. 117-169, imposes a 15-percent minimum tax on the adjusted financial statement income of applicable corporations for taxable years beginning after December 31, 2022 (Exh. NG-RRP-1, at 82).[49] Under the

[49] The adjusted financial statement income is defined as the net income or loss of the taxpayer set forth on the taxpayer's applicable financial statement for such tax year adjusted under 26 C.F.R. § 56A.

provisions of the federal Inflation Reduction Act of 2022, the Company is an applicable corporation subject to corporate alternative minimum tax beginning with fiscal year 2024 (Exh. NG-RRP-1, at 82). The corporate alternative minimum tax represents the excess of the tentative minimum tax, i.e., 15 percent of adjusted financial statement income, over the regular tax, and it can be claimed as a credit against the excess of regular tax over corporate alternative minimum tax in future years (Exh. NG-RRP-1, at 82).

The Company states that the corporate alternative minimum tax should be included in rate base, similar to the plant-related temporary book-tax timing differences that reduce the Company's corporate income tax liability, because the corporate alternative minimum tax increases corporate income tax liability but gives rise to a deferred tax asset (Exhs. DPU 8-1; DPU 8-2; DPU 31-1).[50] The Department finds, however, that the plant-related ADIT balance is primarily attributed to the use of accelerated depreciation authorized by the U.S. Internal Revenue Service ("IRS") for tax purposes and the normalization of tax depreciation for regulatory book purposes. 26 C.F.R. § 168(i)(9)(A). As a result, the tax computed from the regulatory books is higher than that payable to the IRS in the earlier life of the assets, and the resulting accumulated deferred tax balance is available as an interest-free fund for utilities to further invest until taxes are due in later years. D.P.U. 87-59, at 63; D.P.U. 85-137, at 31; D.P.U. 1350, at 42-43; D.P.U. 18200, at 33-34. Therefore, the Department concludes that the corporate alternative minimum tax is not analogous to plant-related ADIT.

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50 The corporate alternative minimum tax results from the Inflation Reduction Act of 2022 and its effect does not impact the income tax expense in the cost of service (Exh. DPU 8-1).

Moreover, contrary to the Company's assertion, the Department's policies regarding ADIT do not allow for all temporary book-tax timing differences (Exh. DPU 8-2). For example, ADIT associated with non-distribution functions, regardless of their book-tax timing difference, are excluded from the calculation of rate base to ensure that only distribution-related functions are included in distribution rates. Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 56 (2008); D.T.E. 02-24/02-25, at 62. Similarly, in cases where ADIT entries carry a negative balance, these balances are zeroed out from a company's ADIT balance to ensure that ratepayers receive the full benefit of deferred income taxes. D.P.U. 09-39, at 118-119. Thus, the Department's ratemaking policy is to match recovery of tax benefits or losses to the recovery of the underlying expenses. 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). For the foregoing reasons, the Department finds no basis to justify the inclusion of ADIT associated with alternative minimum taxes in the Company's rate base calculation. Therefore, the Department denies the proposed corporate alternative minimum tax adjustment. Accordingly, the Department increases the Company's proposed ADIT by $9,545,555.

The Department has reviewed the Company's calculations supporting its remaining adjustments to derive its proposed ADIT balance, and we find them to be reasonable, with the exception of the tax gross-up associated with FAS 109 (Exh. NG-RRP-1, at 81-84; NG-RRP-2, Sch. 11, at 1, 3, Excel, tab P3-ADIT Summary (Rev. 4); NG-RRP-7, at 7 (Rev. 4)). The Department discusses this issue in the next Section below.

E. FAS 109 Regulatory Asset/Liability

1. Introduction

The FAS 109 regulatory liability generally represents overcollections of income taxes to be refunded to customers (Exh. NG-RRP-1, at 83). National Grid proposed a FAS 109 regulatory liability balance of $272,042,757 (Exh. NG-RRP-2, Sch. 11, at 1, 3 (Rev. 4)). To calculate this amount, the Company started with its total test-year-end FAS 109 regulatory liability balance of $298,390,662 less $24,411,445 in adjustments to the test-year-end balance, for an adjusted test-year balance of $273,979,216 (Exh. NG-RRP-2, Sch. 11, at 1, 3 (Rev. 4)). The Company further reduced the adjusted test-year balance by $1,936,460 for known and measurable adjustments as of December 31, 2023, to arrive at its proposed FAS 109 regulatory liability balance of $272,042,757 (Exhs. NG-RRP-2, Sch. 11, at 3, Excel, tab P3-ADIT Summary (Rev. 4); NG-RRP-7, at 7 (Rev. 4)). The Company's FAS 109 regulatory asset/liability balances are grossed-up amounts (Exh. DPU 8-18; RR-DPU-4, Att.). The balance of the FAS 109 regulatory liability primarily consists of excess federal ADIT and deficient state ADIT, offset by the regulatory tax asset for the cumulative tax effect of the equity component of the allowance for funds used during construction ("AFUDC") (Exh. NG-RRP-1, at 83).[51]

[51] The excess federal ADIT liability represents the change in the Company's deferred tax obligations due to the 2017 federal corporate income tax rate change from 35 percent to 21 percent pursuant to the Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97 (Exh. NG-RRP-1, at 83). The deficient state ADIT asset represents the change in the Company's deferred tax obligations due to the 2014 Massachusetts corporate income tax rate applicable to public utilities increasing from 6.5 percent to 8.0 percent (Exh. NG-RRP-1, at 83). The regulatory asset for the cumulative tax effect of AFUDC equity represents the future recovery of the deferred taxes associated with the equity component of the AFUDC, the tax benefit of which was flowed through to customers in the previous years (Exh. NG-RRP-1, at 83).

2. Positions of the Parties

The Company argues that it excluded non-plant related and CIAC-related excess deferred federal income tax and deficient state ADIT as normalizing adjustments, and the deferrals of unamortized investment tax credits and research and development tax credits that are flowed through the income tax expense (Company Brief at 270, citing Exhs. NG-RRP-1, at 83-84; DPU 31-1, Att.). The Company claims that it ensures the rate base neutrality by including deferred taxes associated with the FAS 109 regulatory liability in the ADIT to offset the tax gross-up embedded within the regulatory tax liability balance (Company Brief at 270, citing Exh. DPU 8-18). Further, National Grid contends that the regulatory tax liability itself is a temporary book tax timing difference and needs to be grossed up for additional deferred income taxes to reflect the fact that future increases in revenues will also affect future income taxes payable (Company Brief at 270, citing Exh. DPU 8-18). Therefore, the Company asserts that the gross-up embedded in the regulatory tax liability is fully offset by the deferred tax asset within ADIT (Company Brief at 270, citing Exh. DPU 8-18). According to the Company, it can either include the regulatory tax liability before gross-up and exclude the deferred tax asset associated with it from rate base ADIT or include the total grossed-up balance of the regulatory tax liability and include the associated deferred tax asset within the rate base ADIT to maintain rate base neutrality (Company Brief at 271). No other party addressed the Company's FAS 109 regulatory liability balance on brief.

3. Analysis and Findings

First, we address the Company's tax gross-up of FAS 109 regulatory liability. Rate base represents the investment upon which the company is entitled to an opportunity to earn a return.

Boston Gas Company v. Department of Public Utilities, 367 Mass. 92, 98 (1975). The Department's ratemaking practice is to determine what level of pretax income will generate the allowed return, after provision for income taxes. Kings Grant Water Company, D.P.U. 87-228, at 20 (1988); see also New Bedford Gas and Edison Light Company, D.P.U. 18193, at 10 (1975); Boston Edison Company, D.P.U. 17795, at 9 (1974). Therefore, the Department finds that it is inappropriate for the Company to selectively include tax gross-ups in its rate base items. Accordingly, the Department increases the proposed rate base ADIT balance by $74,322,081, and we reduce the proposed FAS 109 regulatory liability balance by $74,322,081.

Next, consistent with the Department's decision to disallow the tax effect of the equity AFUDC flow-through in Section VIII. below, the Department finds it appropriate to adjust the balance of the flow-through equity AFUDC. Specifically, the Company included a flow-through equity AFUDC balance in the amount of $15,523,397 before tax gross-up in rate base as a component of FAS 109 regulatory asset (Exhs. NG-RRP-7, at 7 (Rev. 4); NG-RRP-2, Sch. 11, at 1, 3 (Rev. 4); DPU 31-1, Att. at 3; RR-DPU-4, Att. at 3). This amount represents the future recovery through depreciation expense for the deferred taxes flowed through associated with the tax effect of the equity AFUDC as of December 31, 2023 (Exhs. NG-RRP-7, at 7 (Rev. 4); NG-RRP-2, Sch. 11, at 1, 3 (Rev. 4); DPU 31-1, Att. at 3; RR-DPU-4, Att. at 3). The Company also provided the equity AFUDC flow-through supporting calculations in which it shows the total equity AFUDC flowed through as of the end of 2023 is $15,007,843 (Exhs. DPU 31-16, Att. 2; DPU 31-20).[52] As such, the Department decreases the rate base by the difference between the year-end balance and the proposed balance, or $515,554.

VI. OPERATIONS AND MAINTENANCE EXPENSES

A. Employee Compensation and Benefits

1. Introduction

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

A company is required to provide a comparative analysis of its compensation expenses to enable a determination of reasonableness by the Department. D.P.U. 96-50 (Phase I) at 47. The

[52] The balance of $15,007,843 of the equity AFUDC flow-through as of the end of 2023 is derived from the balance of the total net of depreciation as of the end of 2024 of $15,374,118 minus the total equity AFUDC flow-through for 2024 of $366,275, i.e., ($1,327,092 + $13,592) × 27.32% = $366,275 (Exh. DPU 31-16, Att. 2, at 2; RR-DPU-37, Att.).

Department evaluates the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory 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).

National Grid's employee compensation program is known as the "Total Rewards Program" (Exh. NG-HRP-1, at 8). The Total Rewards Program encompasses cash compensation, including base and variable pay, and a number of benefits, including medical and dental plans, life insurance, long-term disability, a 401(k) savings plan,[53] retirement plans, other post-employment benefits, vacations, and holidays. (Exh. NG-HRP-1, at 8, 25).[54]

2. Union Wages

a. Introduction

During the test year, National Grid booked $77,133,818 in payroll expenses for union personnel, including base wages, variable pay, and overtime pay (see Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)). For union payroll expenses, $64,613,652 was directly incurred, $10,520,109 was allocated from NGSC, and $2,000,057 was allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 12, at 4, 5, 6 (Rev. 4)). National Grid proposes adjustments to increase the Company's test-year union payroll expense to account for wage increases included in collective bargaining agreements (Exh. NG-HRP-1, at 16-17). Accordingly, the Company

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53 A 401(k) plan is a retirement savings sponsored by an employer and organized under the requirements of the Internal Revenue Code. 26 U.C.S. § 401(k).

54 For purposes of this Section, costs associated with the 401(k) plan, retirement plans, and other post-retirement benefits are referred to as thrift costs.

increased its test-year union payroll expense by $9,481,924 to account for 3.0-percent increases effective May 12, 2023, and May 12, 2024, respectively, for MECo, Nantucket Electric, and NGSC, 3.0-percent increases effective October 16, 2023, and October 16, 2024, respectively, for NGSC TWU Local 101, and 4.0-percent, 3.50-percent, and 3.0-perent increases effective April 30, 2023, March 31, 2024, and March 30, 2025, respectively, for National Grid affiliates (Exhs. WP NG-RRP-4 (Rev. 4); NG-RRP-2, Sch. 12, at 4, 5, 6 (Rev. 4)). This proposed increase is attributable as follows: (1) $7,758,037 in direct costs; (2) $1,663,462 allocated from NGSC; and (3) $60,425 from National Grid affiliates (see Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)).[55]

b. Positions of the Parties

The Company argues that it adjusted labor expense for known and measurable adjustments to both union and non-union wages (Company Brief at 288, citing Exhs. NG-RRP-1, at 25; NG-RRP-2, Sch. 12 (Rev. 3)). The Company claims that its calculation of the known and measurable adjustment to labor expense involves three steps: (1) determining the “steady state” wages for employees as of the end of the test year, March 31, 2023; (2) applying known and measurable wage increases to union and non-union steady state wages; and (3) applying those same known and measurable increases to non-financial metric (or component) variable pay and overtime pay (Company Brief at 289, citing Exh. NG-RRP-1, at 25). Specifically, for union wages, the Company argues that the known and measurable adjustment to test-year union wages included in its revenue requirement reflects contractually agreed upon post-test-year wage increases through April 1, 2025, which in this proceeding is the midpoint of the rate year

55 Each of these adjustments is derived by subtracting the test-year expenses from the rate-year expenses (Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)).

(Company Brief at 290, citing Exhs. NG-RRP-1, at 26; NG-HRP-1, at 15-18).[56] No other party commented on this issue on brief.

c. Analysis and Findings

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 effective date of new base distribution rates; (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.

As noted, April 1, 2025 represents the midpoint of the rate year. The Company's proposed post-test-year union payroll adjustments are based on contractually agreed upon base pay increases, which are scheduled to become effective before April 1, 2025 (Exhs. DPU 25-19; AG 1-42 & Atts.). Thus, the Department finds that the Company's proposal meets the first condition. With respect to the second condition, the increases are based on collective bargaining agreements and memoranda of understanding and accordingly, are known and measurable (Exh. AG 1-42 & Atts.). Thus, the Department finds that the proposed increases meet the second condition.

With respect to the reasonableness of the union wage increases, the Company submitted a comparison of its average union wages with other employers in the Northeast (Exh. NG-HRP-8).

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56 The midpoint of the rate year is the twelve months following the effective date of the rates established with the issuance of the Department's final Order in this proceeding (i.e., October 1, 2024).

The documentation 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 selected union job titles (Exh. NG-HRP-8). Furthermore, the Company's 3.0-percent post-test-year union wage increases are comparable to the Company's union wage increases over the last ten years (Exh. AG-1-41, Att.) Thus, we find that the Company has demonstrated the reasonableness of the union wage increases and meets the third condition.

Based on the above, the Department finds that National Grid has demonstrated, the following: (1) the union salary increases are scheduled to become effective no later than the midpoint of the rate year; (2) there is sufficient documentation demonstrating that the union wage increases are known and measurable; and (3) the union wage increases are reasonable.[57]

3. Non-Union Wages

a. Introduction

During the test year, National Grid booked $95,798,748 in payroll expenses for non-union personnel, including base wages, variable pay, and overtime pay (see Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)). Of this booked amount, $6,607,523 was directly incurred, $88,477,170 was allocated from NGSC, and $714,055 was allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)). The Company proposes to increase test-year non-union payroll expense by $13,508,393 to account for increases that occurred after the end of the test year and were scheduled to become effective no later than

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57 No party objected to the Company's proposed group life insurance costs, thrift costs, or payroll taxes. The Department has reviewed the group life insurance costs, thrift costs, and payroll taxes, and we find them to be appropriate.

six months after the date of the Order (Exhs. NG-RRP-2, Sch. 12, at 4, 5, 6 (Rev. 4); WP NG-RRP-4 (Rev. 4)). This proposed increase comprises the following: (1) $548,459 increase in direct costs; (2) $13,039,042 increase from NGSC; and (3) $79,108 decrease allocated from all other affiliated companies (Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)).[58]

b. Positions of the Parties

As noted above, the Company argues that it adjusted labor expense for known and measurable adjustments to both union and non-union wages, following a three-step process (Company Brief at 288, citing Exhs. NG-RRP-1, at 25; NG-RRP-2, Sch. 12 (Rev. 3)). Specifically, for non-union wages, the Company claims that the known and measurable adjustment reflects a 4.5-percent increase in wages that was effective July 1, 2023, comprising a 4.0-percent base pay increase and a 0.5-percent increase associated with career progressions (Company Brief at 289-290, citing Exh. NG-RRP-1, at 26). The Company maintains that in addition to this increase, a further increase of 5.0 percent as of July 1, 2024, was reflected in the known and measurable adjustment to non-union wages (Company Brief at 289-290, citing Exh. NG-RRP-1, at 26). Lastly, the Company argues that it provided market studies to support the reasonableness of the July 1, 2024 non-union wage increase (Company Brief at 290, citing Exh. DPU 25-21). No other party commented on this issue on brief.

c. Analysis and Findings

To recover an increase in non-union wages, a company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is a historical

58 Each of these adjustments are derived by subtracting the test-year expenses from the rate-year expenses (Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)).

correlation between union and non-union raises; and (3) the non-union increase is reasonable. D.P.U. 96-50 (Phase I) at 42; D.P.U. 95-40, at 21; Fitchburg Gas and Electric Light Company, D.P.U. 1270/1414, at 14 (1983). In addition, only non-union salary increases that are scheduled to become effective no later than six months after the date of the Order may be included in rates. D.P.U. 85-266-A/271-A at 107.

The Company provided a management commitment letter stating that a 5.0-percent payroll increase for non-union employees would take effect on July 1, 2024 (Exh. DPU 25-20, Att. (Supp.)). Based on this information, the Department finds that there was a commitment by management to grant the July 1, 2024 increase.

National Grid provided a historical correlation of non-union and union wage increases and demonstrated that it awarded non-union and union pay increases every year since 2014 (Exh. NG-HRP-7). Between 2014 and 2023, National Grid granted union wage increases between 2.5 percent and 3.0 percent, and non-union wage increases between 0.43 percent and 4.50 percent (Exh. NG-HRP-7). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. D.P.U. 07-71, at 76-77; D.P.U. 87-59-A at 18. Similar to the Company's post-test-year union wage increases noted above, the Company's post-test-year non-union wage increases are comparable to the Company's non-union wage increases over the last ten years (Exh. AG 1-41, Att.).

With respect to the reasonableness of the non-union wages, the Company tests the competitiveness of its base salaries and total cash compensation levels against the external market on an ongoing basis. National Grid annually reviews its salary adjustments and total compensation, both current and projected, against external market trends (Exh. NG-HRP-1, at 13). Specifically, the Company aims to set pay at the median level of the marketplace (Exh. NG-HRP-1, at 11). To determine the median pay level for non-union employees, National Grid benchmarks certain positions within each salary band and compares overall pay for these positions to the 50th percentile of overall pay for comparable jobs in similarly sized companies based on market surveys (Exh. NG-HRP-1, at 11). This comparison shows that for National Grid, non-union salary compensation in 2023 was two percent above the market median, while total compensation was six percent above the market median[59] (Exh. NG-HRP-2, at 4-5). The Department finds that the Company has demonstrated that its total proposed compensation is competitive with the market median and that its increases are aligned with recent industry trends (Exhs. NG-HRP-2, at 5; NG-HRP-6; DPU 25-21, Att. (Supp.)). Specifically, regarding the reasonableness of the July 1, 2024 non-union wage increase, the Company provided various market studies in support of the increase (Exh. DPU 25-21, Att. (Supp.)).[60] The Company relied on survey study results for estimated 2024 salaries that support overall increases of no more than

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59 While the Company's Human Resources Panel testified on the record that National Grid's non-union salary compensation is three percent above the market median and that its total compensation is one percent above the market median, it bases this assertion on "Energy Services (Revenues >$6B)" as a proxy for the market, while the Department, consistent with our analysis in D.P.U. 18-150, views "Energy Services (Total Sample)" as the appropriate proxy for the market. <u>See</u> D.P.U. 18-150, at 220, Exhs. NG-MPH-1, at 12; NG-MPH-2, at 5.

60 The Company provided the following market studies in support of the July 1, 2024 non-union wage increase: WorldatWork Salary Budget Survey 2023-2024; Korn Ferry Compensation and Benefits Report – United States (created on October 26, 2023); Payscale 2023-2024 Salary Budget Survey; 2023 Mercer QuickPulse – US Compensation Planning Survey; Aon plc. 2023 Salary Increase and Turnover Study; and Willis Towers Watson Salary Budget and Planning Report United States 2023 (December Edition) (Exh. DPU 25-21, Att. (Supp.)).

5.0 percent for 2024 (Exh. DPU 25-21, Att. at 2, 4, 6, 8-10, 14 (Supp.)). Thus, we find that the Company has demonstrated the reasonableness of the non-union wage increases.

Based on the above, the Department finds that National Grid has demonstrated the following: (1) that there was an express commitment by management to grant the 5.0-percent non-union wage increase; (2) that there is a historical correlation between union and non-union payroll increases; (3) that the non-union wage increases are reasonable; (4) that non-union salary increases were scheduled to become effective no later than six months after the date of the Department's Order. Accordingly, the Department allows the Company's adjusted non-union payroll expense.

4. Incentive Compensation

a. Introduction

National Grid's variable pay program is known as the Annual Performance Plan ("Performance Plan") (Exh. NG-HRP-1, at 19). The Performance Plan consists of three component objectives: (1) corporate objectives; (2) individual objectives; and (3) financial objectives. The Performance Plan also includes a series of metrics that evaluate whether and to what degree the objectives of the Performance Plan are met (Exh. NG-HRP-1, at 19-24). For Band A and Band B employees, no less than 30 percent of incentive compensation is based on the fulfillment of corporate and individual objectives, while the remaining percentage, up to 70 percent, is based on the fulfillment of financial objectives (Exh. NG-HRP-1, at 21).[61]

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[61] Band A refers to the Company's top officers, including jurisdictional presidents, chief operating officers, and senior vice presidents; Band B refers to less senior officers, e.g., vice presidents (Exh. NG-HRP-1, at 9).

National Grid did not include in its proposed cost of service the variable pay component for Band A and Band B employees that is tied to the achievement of financial metrics (Exh. NG-HRP-1, at 6 n.1, 23). For Band C through Band F employees, 60 percent of incentive compensation is based on the fulfillment of corporate objectives and 40 percent is based on the fulfillment of individual objectives (Exh. NG-HRP-1, at 21).[62] For union employees, the individual objectives relating to customer satisfaction, safety, and reliability account for 100 percent of incentive pay (Exh. NG-HRP-1, at 21).

During the test year, National Grid booked $3,402,335 in incentive compensation for union employees, attributable as follows: (1) $3,070,414 in direct costs; (2) $283,293 allocated from NGSC; and (3) $48,628 allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)). For union employees, National Grid proposes an increase of $201,924 to the incentive compensation expense, based on targeted results for the test year and escalating incentive compensation expenses based on post-test-year wage increases, resulting in a proposed incentive compensation expense for union employees of $3,604,259 (see Exh. NG-RRP-2, Sch. 12, at 4, line 34, column (c), 5, line 41, column (c), 6, line 39, column (c) (Rev. 4)).

During the test year, National Grid booked $13,003,183 in incentive compensation for non-union employees, attributable as follows: (1) $797,322 in direct costs;

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[62] Bands C through F are designated as follows: (1) Band B and Band C are used primarily for directors who report directly to an officer; (2) Band D is for managers who have at least one direct report and report directly to an officer; (3) Band E primarily consists of supervisors who have at least one direct report and who report to a director or manager; and (4) Band F consists of general administrative staff (Exh. NG-HRP-1, at 9).

(2) $12,122,019 allocated from NGSC; and (3) $83,842 allocated from other National Grid affiliates (see Exh. NG-RRP-2, Sch. 12, at 4-6 (Rev. 4)). Because the Company awarded incentive compensation payouts above the target level during the test year, it first reduced the revenue requirement to include only the amount of incentive compensation at target levels (Exhs. NG-RRP-1, at 24; NG-RRP-2, Sch. 12, at 3 (Rev. 4)). The Company proposes an increase of $1,125,762 to the non-union incentive compensation for National Grid by escalating the targeted results for test-year incentive compensation expenses based on post-test-year wage increases, which results in a proposed incentive compensation expense for non-union employees of $14,128,945 for National Grid (see Exh. NG-RRP-2, Sch. 12, at 4, line 34, column (d), 5, line 41, column (d), 6, line 39, column (d) (Rev. 4)).

b. Positions of the Parties

The Company argues that it is not seeking recovery of the variable pay component of incentive compensation that is tied to the achievement of financial metrics (Company Brief at 291, citing Exhs. NG-RRP-1, at 27; NG-HRP-1, at 23; NG-RRP-Rebuttal-1, at 15).[63] The Company maintains that it identified and removed $604,929 in financial-based incentive compensation from its labor schedule (Company Brief at 291, citing Exhs. WP NG-RRP-4 (Rev. 2); NG-RRP-2 (Rev. 3)). No other party commented on this issue of brief.

63 As noted above, the variable pay component of incentive compensation tied to financial metrics is applicable to non-union, Band A and Band B employees only (Exh. NG-HRP-1, at 6 n.1, 23).

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 amounts are reasonable 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.

First, the Department must determine whether the costs associated with the Performance Plan are reasonable. The Company awarded incentive compensation payouts to its employees above the target level during the test year. As a result, the Company reduced the cost of service to include only the amount of incentive compensation at target levels (Exhs. NG-RRP-1, at 24; NG-RRP-2, Sch. 12, at 3 (Rev. 4)). In addition, National Grid further reduced variable pay to reflect the administrative and general overhead study reclassification from O&M to capital (Exhs. NG-RRP-1, at 20; NG-RRP-2, Sch. 12, at 3 (Rev. 4)). Based on our review of this evidence, the Department finds that National Grid has demonstrated that the costs are reasonable.

Second, the Department must determine whether the Company's Performance Plan is reasonable in design. The record shows that National Grid's Performance Plan for its Band A and Band B non-union employees is based on financial objectives and individual objectives (Exhs. NG-HRP-1, at 21, 23; NG-HRP-4, at 1; NG-HRP-5, at 1). National Grid has not sought to recover the variable pay component tied to the achievement of financial metrics for Band A and Band B non-union employees. Incentive payment to the employees in Band A or Band B is based on the employees' performances against pre-determined goals (Exh. NG-HRP-4, at 2). Individual performance is determined and evaluated by their manager (Exh. NG-HRP-4, at 1-2).

Incentive payment for employees falling within Bands C through F is based instead on corporate objectives built around four strategic priorities: (1) enabling the energy transition for all customers; (2) delivering for customers efficiently; (3) growing organizational capability; and (4) empowering employees to achieve great performance and individual performance (Exhs. NG-HRP-1, at 20-22; NG-HRP-5). Thus, the Performance Plan encourages good employee performance directly by rewarding non-union employees for achieving personal goals and contributing to the financial success of National Grid (Exhs. NG-HRP-1, at 7-8; NG-HRP-4; NG-HRP-5). Further, National Grid states that it ensures that its employees are committed to meeting customer needs by establishing performance goals that are based on providing safe, reliable, and efficient services to customers (Exhs. NG-HRP-1, at 19-20; NG-HRP-4, at 1; NG-HRP-5, at 1). With 100 percent of the payout for union employees tied to the achievement of enabling the energy transition, safety, reliability, customer metrics, and efficiencies, the variable pay plan is therefore specifically designed to focus this group on objectives that benefit customers (Exh. NG-HRP-1, at 21). Moreover, National Grid has provided comprehensive analyses of base salaries and target total compensation compared to the market (Exhs. NG-HRP-1, at 6; NG-HRP-2; NG-HRP-3; NG-HRP-9). The Department finds, based on the results of these studies and the foregoing considerations, that National Grid has demonstrated that the Performance Plan is reasonable in design.

Based on the analysis above, the Department finds that National Grid has adequately demonstrated that its Performance Plan encourages good employee performance and results in benefits to ratepayers. Therefore, the Department permits the inclusion of National Grid's incentive compensation costs in its cost of service.

5. Employee Recognition Expenses

a. Introduction

During the test year, the Company incurred $1,274,643[64] in employee recognition expenses associated with its Appreciate Program comprising $1,068,892 in performance recognition awards, $45,393 in milestone awards, and $160,358 related to fees, taxes, and timing differences due to accruals (Exhs. AG 10-14 & Supp.; AG 20-1 & Supp.). The Company states that performance recognition awards are granted to employees who go above and beyond their normal day job or annual performance objectives while milestone awards are granted to employees when they reach milestone service anniversaries (Exh. AG 20-1). Performance recognition awards and milestone awards consist of appreciation points, which the employee can then use to purchase products and services through a rewards store (Exh. AG 20-1 (Supp.); Tr. 2, at 265-266; RR-AG-8 & Att.). During evidentiary hearings, the Company clarified that its Appreciate Program and the associated total employee recognition expenses are separate items from the Company's Performance Plan and the associated incentive compensation component of its employee compensation adjustment discussed above (Tr. 8, at 1182).

64 The $1,274,643 in Appreciate Program costs comprise $1,023,763 in performance recognition awards, $43,171 in milestone awards, $45,129 in performance recognition awards from affiliates, $2,222 in milestone awards from affiliates, $10,295 in delivery fees, $1,756 in taxes, $8,273 in management fees, and $140,034 related to timing differences due to accruals (RR-AG-26). After applying its proposed inflation adjustment, the Company seeks to include in its revenue requirement $1,354,936 comprising $1,294,689 in performance recognition awards and $60,257 in milestone awards (Exhs. AG 10-14 & Supp.; AG 20-1 & Supp.; Tr. 2, at 260-278, 1181-1185) (see Schedule 2A).

b. Positions of the Parties

i. Attorney General

The Attorney General argues that for the Company to recover employee recognition expenses, the Company must demonstrate that the costs benefit Massachusetts ratepayers and are reasonable and prudently incurred (Attorney General Brief at 101, citing D.P.U. 11-01/D.P.U. 11-02, at 323; Oxford Water Company, D.P.U. 1699, at 13 (1984); Attorney General Reply Brief at 31). She argues that the Appreciate Program costs fall short in meeting all three requirements (Attorney General Brief at 101; Attorney General Reply Brief at 31-32).

Regarding the benefit to ratepayers, the Attorney General asserts that while the Company claims that employee recognition leads to better employee retention, which allows it to offer better service to customers, the Company failed to demonstrate a measurable increase in employee engagement (Attorney General Brief at 102, citing Exh. AG 20-1, at 2 (Supp.); Attorney General Reply Brief at 32). She maintains that the employee survey, which measures employee engagement, demonstrates that the Company maintained the same level of employee engagement between 2020 and 2024, which is not a sufficient showing of benefit to ratepayers (Attorney General Brief at 102-103, citing Exh. AG 20-1, at 2-3 (Supp.); Attorney General Reply Brief at 33, citing Exhs. AG 10-14 & Supp.; AG 20-1 & Supp.).

In addition, she argues that even if the Company could show that its recognition programs promote employee good will and improve productivity to some degree, the unreasonably high costs of the Appreciate Program offset any possible benefits of incentivizing employee performance and service, citing to the energy burdens of the Company's customers

(Attorney General Brief at 103). The Attorney General also rebuts the Company's contention that research supports the use of non-cash gifts over cash payments for employee recognition (Attorney General Reply Brief at 32, citing Company Brief at 363-364; Exhs. AG 20-1 & Supp.; Tr. 2, at 276). The Attorney General asserts that the "research" presented by the Company consisted of marketing bulletins from a third-party contractor that is in the business of selling recognition programs to companies (Attorney General Reply Brief at 32, citing Tr. 2, at 276).

Regarding the reasonableness of the employee recognition expenses associated with the Appreciate Program, the Attorney General argues that the Department has recognized a difference between modest costs for employee gifts meeting the Department's standard for recovery and unreasonable or excessive costs that do not meet this standard (Attorney General Brief at 103). She claims the Department has previously found that non-monetary gifts ranging from $50-$250 constituted a modest cost (Attorney General Brief at 104, citing D.P.U. 22-22, at 167-171). Further, the Attorney General maintains that the total of $1,354,936 in employee recognition expenses is more than fifty times as costly as the program considered by the Department in D.P.U. 22-22 (Attorney General Brief at 104, citing Exh. AG 10-14, at 1 (Supp.)). She disputes the Company's claim that the Appreciate Program awards are for "above and beyond" performance since 67.91 percent of full-time employees received at least one award in the test year (Attorney General Brief at 104, citing RR-AG-11). The Attorney General also argues that the value of the individual awards is significantly higher than the awards considered by the Department in D.P.U. 22-22, with awards up to $6,273, and 20 percent of awards being greater than $250 in value (Attorney General Brief at 104, citing Exh. AG 10-14 (Supp.); RR-AG-11). She also argues that the Company's spending in this area far exceeds its own historical practices as well as Massachusetts utility standards (Attorney General Brief at 104, citing D.P.U. 18-150; D.P.U. 22-22, at 171).

Regarding the prudency of the employee recognition expenses associated with the Appreciate Program, the Attorney General raises concerns about the transparency, necessity, and justification of the costs (Attorney General Brief at 105, citing Tr. 8, at 1044–1211). She takes issue with both the amount of expenses, which she states is "staggering," as well as some of the component costs of this total amount, such as administrative and shipping costs, which she claims were imprudent (Attorney General Brief at 106, citing Exh. AG 10-14, at 1; RR-AG-26, at 1). The Attorney General also argues that it is important to consider the employee recognition expenses associated with the Appreciate Program within the context of the Company's highly competitive salaries and generous incentive compensation plan (Attorney General Brief at 105; Attorney General Reply Brief at 34).

ii. Company

National Grid contends that the Department should allow the Company's proposed employee recognition expenses to be included in rates (Company Brief at 365). The Company claims that the Appreciate Program reinforces National Grid's values, creates a culture of engagement, fuels great work, and drives desired outcomes (Company Brief at 363, citing Exh. AG 20-1). The Company argues that, in principle, performance recognition awards are not given for day-to-day work activities or for work that forms part of a specific performance objective unless the effort required to perform that work went beyond normal expectations (Company Brief at 363, citing Exh. AG 20-1; Company Reply Brief at 52, citing Tr. 2, at 267).

The Company argues that the Appreciate Program is important because research consistently shows that there is a direct link between praise and appreciation and employee engagement, which in turn has a direct link to employee performance (Company Brief at 363-364, citing Exh. AG 20-1, Atts. 1-2). National Grid further argues that recognizing employees improves the Company's ability to attract, retain, and motivate skilled and capable employees that are necessary to provide safe, reliable, and efficient service to customers (Company Brief at 104, citing Exh. AG 20-1, Atts. 1-2; Company Reply Brief at 52, citing Exh. NG-HRP-1, at 7). Moreover, the Company maintains that market research indicates that supplementing an employee's salary and annual variable compensation with another form of cash payment is not the best way to show appreciation, and that cash awards are not as memorable as gifts, with the impact of a payment being short-lived (Company Brief at 104, citing Exh. AG 20-1, Atts. 1-2). The Company asserts that recognition inspires continual great work and innovation by making ideas and accomplishments visible across the entire organization (Company Brief at 104, citing Exh. AG 20-1, Atts. 1-2; Company Reply Brief at 52).

National Grid maintains that it has experienced a general upward trend in employee engagement, based on employee feedback from its annual employee survey, which it asserts correlates to the incremental usage of the Company's Appreciate Program (Company Brief at 364, citing Exh. AG-20-1). Based on these factors, the Company claims that it has met its burden to continue to include employee performance recognition costs from the Appreciate Program in its cost of service, consistent with prior years (Company Reply Brief at 53).

c. Analysis and Findings

The Company bears the burden of demonstrating that its proposed employee recognition expenses 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. D.T.E. 03-40, at 140-141.

As noted above, the employee recognition expenses associated with the Company's Appreciate Program sought for recovery in this proceeding are composed of performance recognition awards and milestone awards (Exhs. AG 20-1; AG 20-1 (Supp.)). Regarding the expenses associated with the milestone awards, the Department has previously found that attracting and retaining skilled employees ultimately benefits customers through the sustained provision of safe and reliable service. D.P.U. 22-22, at 171. Here the milestone awards recognize employees' years of service, thereby encouraging employee retention (Exh. AG 20-1 (Supp.)). Based on the record evidence, we also find that the costs are reasonable and prudently incurred (Exh. AG 20-1 (Supp.); RR-AG-11; RR-AG-26). Therefore, based on the foregoing, we allow inclusion of test-year costs[65] of $51,920[66] associated with its milestone awards component of its Appreciate Program in its cost of service.

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65 The Company applied an inflation factor to its test-year expenses for the milestone awards (Exh. AG 10-14 (Supp.)). These allowed test-year O&M costs are subject to the inflation allowance (see Section VI.L. below).

66 $51,920 represents direct milestone awards of $43,171, affiliate milestone awards of $2,222, and the approximate portion of the remaining costs of test-year delivery fees, taxes, management fees, and costs related to timing differences due to accruals attributable to the milestone awards (see RR-AG-11; RR-AG-26). As the Company did

Regarding the expenses associated with performance recognition awards, the record evidence demonstrates that the employee engagement score over the five-year period has been relatively static (Exh. AG 20-1 (Supp.)). Accordingly, the Company has failed to sufficiently demonstrate direct causation between the performance recognition awards and employee performance and any direct benefit to ratepayers from the performance recognition awards.

With respect to the reasonableness of the costs, the Department has previously allowed companies to include in their revenue requirement expenses that serve to attract and maintain skilled employees. D.P.U. 22-22, at 171; Milford Water Company, D.P.U. 12-86, at 164 (2013). For example, the Department allowed NSTAR Electric to include $20,727 in its proposed cost of service, noting that the costs were modest. D.P.U. 22-22, at 171. The Department also noted that the maximum value of an award was $275 for 50 years of service. D.P.U. 22-22, at 168. The Department also permitted Milford Water Company to recover $2,183 in employee welfare expenditures, as such expenditures had a positive effect on employee morale. D.P.U. 12-86, at 164. In the instant proceeding, there were numerous awards exceeding $275 with the maximum award being $6,273 (RR-AG-11. Att.). In fact, almost 20 percent of the awards exceeded the maximum value of $275 that was awarded by NSTAR Electric (RR-AG-11, Att.). D.P.U. 22-22, at 171. We find that the value of National Grid's awards is not consistent with the

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not provide a breakdown of the $160,358 in remaining fees and costs attributable to performance recognition awards and milestone awards, the Department finds it appropriate to allow for inclusion in the Company's cost of service the approximate portion of these costs, allocated to the milestone awards derived by using a ratio of the total milestone awards (i.e., $45,393) to the total combined milestone and performance awards amount (i.e., $1,114,285), and applied to the remaining fees and costs of $160,358 (RR-AG-26). Accordingly, 4.07 percent of $160,358 equals $6,527.

modest costs previously allowed by the Department. D.P.U. 22-22, at 171; D.P.U. 12-86, at 164. Thus, we find that the amount National Grid seeks to include for its performance recognition awards is unreasonable and, as such, the Department need not consider whether the costs were prudently incurred.[67] Therefore, we direct the Company to reduce its cost of service by the remaining test year balance in employee recognition expenses associated with its Appreciate Program of $1,222,723.

6. Healthcare Expenses

a. Introduction

During the test year, National Grid booked $22,912,065 in healthcare expense (Exhs. NG-RRP-1, at 28; NG-RRP-2, Sch. 13, at 1 (Rev. 4)). The Company then made a normalizing adjustment to test-year healthcare expense to redistribute major storm costs, to remove basic service administrative costs, and to remove costs associated with the Company's student loan repayment program that the Company is not seeking for recovery (Exhs. NG-RRP-1, at 28-29; NG-RRP-2, Sch. 13, at 1 (Rev. 4)). This normalizing adjustment resulted in a $859,774 reduction to healthcare expense (Exh. NG-RRP-2, Sch. 13, at 1, 3 (Rev. 4)). The adjusted test-year healthcare expense is $22,052,291, of which $10,134,389 were

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67 With respect to the Company's argument that it met its burden to Appreciate Program costs "consistent with prior years," the Department notes that our previous silence on the reasonableness of a component of the Company's revenue requirement did not indicate our acceptance of the proposal. A general principle of administrative law is that an administrative body can only go against precedent where it adequately explicates the basis of its new interpretation. United Automobile Workers v. National Labor Relations Board, 802 F.2d 969, 974 (1986). While the Department may have inadvertently allowed the recovery of Appreciate Program costs in prior proceedings, the Department did not intend to change its treatment of this category of costs.

direct costs, $11,661,831 were allocated from NGSC, and $256,070 were allocated from other National Grid affiliates (Exh. NG-RRP-2, Sch. 13, at 1 (Rev. 4)). National Grid proposed additional adjustments, resulting in a reduction to healthcare expense of $334,709, consisting of a $257,893 directly allocated expense, and a $592,603 reduction to heath care expense attributed to NGSC (Exh. NG-RRP-2, Sch. 13, at 2 (Rev. 4)). The Company's proposed additional adjustments to test-year healthcare expense reflect changes based on the Company's individual plan cost rates that will be in effect for calendar year 2024 (Exh. NG-RRP-1, at 29). The Company calculated these adjustments by: (1) calculating an average healthcare expense per employee using the 2024 working rates; and (2) multiplying that amount by the number of enrolled employees as of March 31, 2023 (Exh. NG-RRP-1, at 29). The Company allocated the total amount to O&M, and further allocated the costs to MECo and Nantucket Electric (Exh. NG-RRP-1, at 29). The resulting healthcare expense, after the normalizing adjustment and the additional adjustments, is $21,717,581 (Exh. NG-RRP-2, Sch. 13, at 2 (Rev. 4)).

b. Positions of the Parties

The Company claims that its proposed adjustment to test-year healthcare expense reflects known and measurable changes based on the Company's individual plan costs rates that will be in effect for calendar year 2024, which is the most recent data available regarding healthcare expense (Company Brief at 292, citing Exh. NG-RRP-1, at 29). On brief, the Company summarizes its calculations (Company Brief at 292). No other party commented on this issue on brief.

c. Analysis and Findings

To be included in rates, healthcare expenses, such as medical, dental, and vision, must be reasonable. D.T.E. 01-56, at 60-61; D.P.U. 92-78, at 29-30; Nantucket Electric Company, D.P.U. 91-106/91-138, at 53 (1991). Further, companies must demonstrate that they have acted to contain their healthcare costs in a reasonable, effective manner. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; D.P.U. 91-106/91-138, at 53. Finally, any post-test-year adjustments to healthcare expense must be known and measurable. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986).

The Department finds that National Grid's healthcare expenses are reasonable and that the Company has taken reasonable and effective measures to contain these costs (Exh. NG-HRP-1, at 27-29). For example, the majority of National Grid health benefit plans are self-insured, which tends to produce cost savings (Exh. NG-HRP-1, at 28). Further, the Company periodically conducts competitive bidding processes to achieve the lowest administrative fees and premiums when rolling out a new program or upon the expiration of an existing contract (Exh. NG-HRP-1, at 8). For example, National Grid recently negotiated improved pricing with CVS Caremark, its national Pharmacy Benefits Manager (Exh. NG-HRP-1, at 28). The Company's medical benefits plan changes included increased deductibles and out of pocket maximums, decreased coinsurance percentage, as well as the introduction of a specialty drug program which covers specialty drugs on the plan's formulary at 100 percent by maximizing the value of the manufacturer's coupons on the employee's behalf (Exh. NG-HRP-1, at 31-33).

Turning to National Grid's post-test-year adjustment to its healthcare expense, the Department finds that the working rates used by the Company for this adjustment are based on National Grid's actual insurance claims and experience cost trends (Exh. NG-HRP-10). The Department previously has denied recovery of pro forma healthcare expenses based on working rates derived from actuarial estimates encompassing a broad-based pool of insured parties. D.P.U. 15-80/D.P.U. 15-81, at 137; D.P.U. 13-90, at 94. In this case, however, National Grid's working rates are derived using National Grid's own claims experience and plan design (Exh. NG-HRP-1, at 36-38). The Company's external benefits consultants developed the working rate using actuarial principles, and the rates are based on the Company's actual insurance claims and cost trends experience during the two years prior to the test year (Exh. NG-HRP-1, at 36-37). Therefore, we conclude that National Grid's proposed working rates are sufficiently correlated to its own experience, rather than that of a broad-based poll of insured entities, to warrant their use in determining the Company's healthcare expense. D.P.U. 17-170, at 103; D.P.U. 15-155, at 176-177. Based on the forgoing reasons, the Department accepts the Company's proposed healthcare expense of $21,717,581.

B. Depreciation

1. Introduction

During the test year, National Grid booked $171,577,148 in depreciation expense (Exh. NG-RRP-2, Sch. 6, at 1 (Rev. 4)). The Company initially proposed a rate-year depreciation expense of $198,181,087 based on proposed depreciation accrual rates (Exhs. NG-RRP-1, at 66; NG-RRP-2, Sch. 6, at 1). During the proceeding, the Company adjusted its depreciable plant balance, resulting in an updated proposed depreciation expense of

$197,426,248 (Exh. NG-RRP-2, Sch. 6, at 3 (Rev. 4)). The Company also proposes to remove all meter-related depreciation expenses and to reflect those costs outside of base distribution rates in the AMI factor ("AMIF"), with costs to be fully recovered by the end of 2028, pursuant to Second Grid Modernization Plans, D.P.U. 21-80-B/D.P.U. 21-81-B/D.P.U. 21-82-B at 300 (2022) ("Second Grid Modernization") and consistent with Department directives in D.P.U. 22-22, at 184-185 (Exhs. NG-RRP-1, at 67; NG-RRP-2, Sch. 6, at 3 (Rev. 4)).

In support of its proposed accrual rates, the Company presented a depreciation study using plant data as of December 31, 2022, and employed the overall straight-line method,[68] average service life ("ASL") process, and remaining life technique to estimate the proposed depreciation accrual rates for most accounts (Exhs. NG-NWA-1, at 7-8; NG-NWA-3). The Company's depreciation study analyzed accounting entries of plant transactions from the period 2004 through 2022 (Exhs. NG-NWA-1, at 8; NG-NWA-3, at 34 (Rev.)). National Grid estimated the service life and net salvage[69] characteristics for depreciable plant accounts and used the estimates to calculate composite remaining lives and annual depreciation accrual rates for each account (Exhs. NG-NWA-1, at 13-15; NG-NWA-3, at 34-35 (Rev.)). To determine service lives, the Company used the retirement rate method to create life tables, which, when

[68] For National Grid's general plant assets, specifically general plant accounts 391.00, 393.00, 394.00, 395.00, 397.00, and 398.00, the Company used the straight-line method of amortization (Exhs. NG-NWA-1, at 7, 16; NG-NWA-3, at 45 (Rev.)).

[69] 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. NG-NWA-1, at 13).

plotted, show an original survivor curve that is then compared to Iowa Curves[70] to determine an ASL for each plant account (Exhs. NG-NWA-1, at 10; NG-NWA-3, at 10-11 (Rev.)). To determine net salvage values, the Company reviewed its actual salvage and cost of removal data for the period 2004 through 2022 (Exhs. NG-NWA-1, at 13; NG-NWA-3, at 39 (Rev.)).

2. Positions of Parties

a. Attorney General

The Attorney General argues that for six accounts, the Company's proposed ASLs are unreasonably short and thus result in unreasonably high depreciation rates and expense (Attorney General Brief at 119-120).[71] The Attorney General asserts that her proposed curves and ASLs are more appropriate than those proffered by the Company (Attorney General Brief at 121). Further, the Attorney General contends that National Grid did not demonstrate that increased load growth and electrification will impact service lives (Attorney General Brief at 122, citing Exh. NG-NWA-Rebuttal-1, at 2; Attorney General Reply Brief at 37-38, citing Exh. NG-NWA-Rebuttal-1, at 7). The Attorney General maintains that the Company

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70 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. NG-NWA-1, at 9; NG-NWA-3, at 14-20 (Rev.)). 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.

71 The six accounts for which the Attorney General provides proposed curves and ASLs are: (1) Account 364.00, Poles, Towers, and Fixtures; (2) Account 365.00, Overhead Conductors and Devices; (3) Account 366.00, Underground Conduit; (4) Account 368.30, Line Transformers – Install Cost; (5) Account 369.10, Overhead Services; and (6) Account 369.20, Underground Services (Attorney General Brief at 119).

exaggerates the immediacy of the transition away from natural gas (Attorney General Brief at 121-122). According to the Attorney General, the instant proceeding will set rates for the next five years, which is contrary to the notion that depreciation is a forecast of what will occur over the useful lives of the assets (Attorney General Reply Brief at 38, citing Company Brief at 450). Finally, the Attorney General argues that the Company failed to provide sufficient evidence that the depreciation rate will diverge so significantly from the historical data during the term of the rate plan (Attorney General Brief at 123). Based on her proposed depreciation accrual rates, the Attorney General recommends that the Department reduce National Grid's depreciation expense by $17,497,706 (Attorney General Brief at 119).

b. Company

The Company argues that, when estimating future service lives and net salvage, one must consider that the Commonwealth's transition to net zero GHG emissions will have significant impacts on the electric distribution system, which will result in increased retirement or replacement rates of electric distribution assets (Company Brief at 438, citing Exh. NG-NWA-Rebuttal-1, at 3, 9-10). The Company asserts that the estimation of service lives should not be limited solely to mathematical analyses, and that the combined impact of capacity replacements, obsolescence, new technologies, and other factors will lead to shorter service lives for many accounts (Company Brief at 443, citing Exh. AG 2-17). National Grid maintains that absent explicit Department guidance, the Company has not proposed specific adjustments to service lives or depreciation rates to account for the impacts of the transition to net zero (Company Brief at 444, citing Exh. NG-NWA-1, at 12). The Company argues, however, that: (1) transmission and distribution assets will need to be upgraded or replaced to incorporate technologies such as DER; (2) load growth and changing load profiles resulting from electrification will require upgrades and replacements; (3) new technology added to the grid typically exhibits shorter service lives, particularly digital equipment; and (4) climate change will result in increased resilience and reliability investments, as well as increased wear and tear of equipment (Company Brief at 444, citing Exh. DPU 19-1). The Company avers that the combined impacts of these factors will result in an increased pace of asset replacements and shorter service lives than historically observed (Company Brief at 444, citing Exh. DPU 19-1). Finally, the Company asserts that as more data and information become available in future depreciation studies, it is likely that asset lives may need to be shortened (Company Brief at 444, citing Exh. DPU 19-1).

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 the engineering and statistical analysis of its witness, 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. D.T.E. 02-24/25, at 132; D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historical performance to assess future events, a degree of subjectivity is inevitable.[72] 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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72 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. Account-by-Account Analysis

i. Account 364.00 (Poles, Towers, and Fixtures)

The current accrual rate for Account 364.00 is 3.15 percent, based on a 45-S1.5 curve (Exh. NG-NWA-4). The Company proposes a 45-R2.5 curve, which produces an accrual rate of 3.62 percent, while the Attorney General proposes a 49-R2 curve with an accrual rate of 3.06 percent (Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); NG-NWA-3, at 50 (Rev.); NG-NWA-4; AG-DJG-4; AG-DJG-5, at 1; AG-DJG-6).

The Department finds that the Attorney General's proposed curve provides a better fit to the Company's observed data both visually and mathematically, exhibiting a sum of squared differences ("SSD")[73] of 0.1273 compared to the Company's curve, which has an SSD of 0.7122 (Exhs. AG-DJG-7, at 2; NG-NWA-Rebuttal-1, at 21). Further, the Attorney General's proposed curve is more consistent with the curve-life combinations the Department has approved for other EDCs in recent years.[74] Moreover, a review of curve-life combinations used by other utilities demonstrates that the mean ASL used for Account 364.00 is greater than 45 years, with a majority of utilities using an ASL of 49 years or longer (Exh. AG 2-18, Att.). National Grid's proposed curve and ASL take into consideration the Commonwealth's transition to net zero and its impact on the retirement or replacement rate of assets, though the Company has not proposed

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73 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 15).

74 In D.P.U. 22-22, the Department accepted NSTAR Electric's uncontested use of 62-R1.5 curve for this account. D.P.U. 22-22, Exh. ES-JJS-2, at 37, 86. Subsequently, in D.P.U. 23-80/D.P.U. 23-81, at 191, the Department accepted Unitil's proposed 55-R2.5 curve.

specific service life adjustments to that effect (Exhs. NG-NWA-1, at 12; NG-NWA-3, at 36 (Rev.); DPU 19-1). While the Department has considered the context of electrification as a reason not to extend ASLs beyond what a company's historical retirement data shows, here the Company's proposed ASL is visibly shorter than what the data suggest (Exhs. NG-NWA-3, at 95 (Rev.); AG-DJG-1, at 13). See D.P.U. 23-80/D.P.U. 23-81, at 189-193. Thus, the Department is not persuaded that the potential for increased electrification warrants such a deviation from observed data (i.e., a visibly shorter ASL when compared to the data) as that proposed by the Company (Exhs. NG-NWA-3, at 95 (Rev.); NG-NWA-Rebuttal-1, at 21). Based on the foregoing analysis, the Department finds the Attorney General's proposed 49-R2 curve is reasonable and appropriate. Thus, we approve an accrual rate of 3.06 percent for Account 364.00, Poles, Towers and Fixtures which, when applied to the adjusted plant balance of $917,729,549, results in a depreciation expense of $28,082,524, representing a decrease of $5,139,286 from the Company's proposed depreciation expense of $33,221,810 for this account (Exhs. NG-RRP-2, Sch. 6, at 1, 3 (Rev. 4); AG-DJG-1, at 4).

ii. Account 365.00 (Overhead Conductors and Devices)

The current accrual rate for Account 365.00 is 3.17 percent, based on a 45-SC curve (Exh. NG-NWA-4). The Company proposes a 45-R0.5 curve, which results in an accrual rate of 3.12 percent, while the Attorney General proposes a 51-R0.5 curve, which results in an accrual rate of 2.71 percent (Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); NG-NWA-3, at 50 (Rev.); NG-NWA-4; AG-DJG-4; AG-DJG-5, at 1; AG-DJG-6).

The Department finds that the Attorney General's curve provides a better mathematical fit to the Company's data, exhibiting an SSD of 0.4134, compared to the Company's curve, which has an SSD of 0.7123 (Exh. AG-DJG-8, at 2). With respect to visual fit, neither proposed curve approximates the retirement data well, with the Attorney General's curve exceeding most of the retirements up to 45 years while the Company's curve falls short of the retirements from 35 years and beyond (Exh. NG-NWA-Rebuttal-1, at 24). The mean industry ASL for this account is 54 years, with a majority of utilities using an ASL greater than 50 years (Exh. AG 2-18, Att.). Further, the Attorney General's proposal is more consistent with what the Department has approved for other EDCs in recent years.[75] Based on the foregoing analysis, the Department finds the Attorney General's proposed 51-R0.5 curve is reasonable and appropriate. Therefore, we approve an accrual rate of 2.71 percent for Account 365.00, Overhead Conductors and Devices which, when applied to the adjusted plant balance of $1,054,394,644, results in an annual depreciation expense of $28,574,095 (Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); AG-DJG-1, at 4). As such, the Department decreases the Company's proposed rate-year depreciation expense of $32,897,113 for Account 365.00 by $4,323,018 (Exh. NG-RRP-2, Sch. 6, at 3 (Rev. 4)).

iii. Account 366.00 (Underground Conduit)

The current accrual rate for Account 366.00 is 2.21 percent, based on a 50-S4 curve (Exh. NG-NWA-4). The Company proposes a 50-R3 curve and accrual rate of 2.94 percent, while the Attorney General proposes a 60-R3 curve and accrual rate of 2.32 percent

75 In D.P.U. 22-22, at 182-183, the Department accepted NSTAR Electric's use of a 60-R0.5 curve for this account. In D.P.U. 23-80/D.P.U. 23-81, the Department accepted Unitil's uncontested use of a 50-R1.5 curve. D.P.U. 23-80/D.P.U. 23-81, Exh. Unitil-NWA-3, at 109 (electric).

(Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); NG-NWA-3 (Rev.) at 50; NG-NWA-4; AG-DJG-1, at 4; AG-DJG-4; AG-DJG-5, at 1; AG-DJG-6).

The Department finds that neither the Company's nor the Attorney General's curve provides a meaningful fit as the retirement data for this account is limited, with only two percent of plant being retired during the study period (Exh. NG-NWA-3). While the retirement experience for this account is limited, the Department notes that with 98 percent of assets surviving up to 60 years in age, it is reasonable to conclude that a longer ASL than the Company's proposed 50 years is warranted (Exhs. NG-NWA-3, at 101-103 (Rev.); NG-NWA-Rebuttal-1, at 26; AG-DJG-1, at 18; AG-DJG-9, at 2). Further, a review of other industry utilities with Account 366.00 shows that the industry mean ASL is 65, which suggests the Attorney General's proposed curve is more reasonable (Exh. AG 2-18, Att.). Finally, the Attorney General's proposal is more consistent with ASLs that the Department approved for other EDCs in recent years.[76] Based on the foregoing analysis, the Department finds the Attorney General's proposed 60-R3 curve is reasonable and appropriate. Therefore, we approve an accrual rate of 2.32 percent for Account 366.00, Underground Conduit which, when applied to the adjusted plant balance of $376,758,509, produces an annual depreciation expense of $8,740,797 (Exh. NG-RRP-2, Sch. 6, at 3 (Rev. 4)). As such, the Department decreases the Company's proposed rate-year depreciation expense of $11,076,700 for Account 366.00 by $2,335,903 (Exh. NG-RRP-2, Sch. 6, at 3 (Rev. 4)).

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[76] In D.P.U. 22-22, at 183-184, the Department accepted NSTAR Electric's use of a 75-R3 curve for this account. In D.P.U. 23-80/D.P.U. 23-81, the Department accepted Unitil's uncontested use of a 70-R4 curve. D.P.U. 23-80/D.P.U. 23-81, Exh. Unitil-NWA-3, at 116 (electric).

iv. Account 368.30 (Line Transformers – Install Cost)

The current accrual rate for Account 368.30 is 3.72 percent, based on a 35-R3 curve (Exh. NG-NWA-4). The Company proposes a 35-R2 curve with an accrual rate of 4.04 percent, while the Attorney General proposes a 41-R1.5 curve with an accrual rate of 3.22 percent (Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); NG-NWA-3, at 50 (Rev.); NG-NWA-4; AG-DJG-4; AG-DJG-5, at 1; AG-DJG-6).

The Department finds that both the Attorney General's and the Company's proposed curve provide statistically similar fits to the historical retirement data, with SSDs of 0.4005 and 0.4557, respectively (Exh. AG-DJG-10, at 2).[77] Visually, both curves provide decent approximations of the retirement data for a large portion of the curve, but the Attorney General's curve exceeds the retirement data significantly after about 40 years (Exhs. NG-NWA-Rebuttal-1, at 27; AG-DJG-1, at 20). Moreover, there is limited industry data regarding this specific subaccount, with only one company having curve information for an account titled "Transformers – Install Cost" (Exh. AG 2-18, Att.). The Department finds that, because of the close statistical fit of both curves and the limited industry data, there is no compelling reason to depart from the Company's currently approved ASL of 35 years (Exh. NG-NWA-4). D.P.U. 23-80/D.P.U. 23-81, at 191; D.P.U. 22-22, at 183; D.P.U. 18-150, at 303. As such, the Department finds National Grid's proposed 35-R2 curve to be reasonable and appropriate. We

[77] The Attorney General's expert testimony provides SSDs of 0.2121 and 0.307 for the Attorney General's and the Company's proposed curves, respectively; however, these results are for a truncated portion of the data, while the SSDs above of 0.4005 and 0.4557 are calculated based on the entire set of retirement data for Account 368.30 (Exhs. AG-DJG-1, at 20; AG-DJG-10, at 2).

therefore approve an accrual rate of 4.04 percent for Account 368.30, Line Transformers – Install Cost.

v. Account 369.10 (Overhead Services)

The current accrual rate for Account 369.10 is 3.97 percent, based on a 55-S1.5 curve (Exh. NG-NWA-4). The Company proposes to retain the current curve-life combination of 55-S1.5, with an accrual rate of 4.85 percent while the Attorney General proposes a 64-R2 curve with an accrual rate of 3.72 percent (Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); NG-NWA-3, at 50 (Rev.); NG-NWA-4; AG-DJG-4; AG-DJG-5, at 1; AG-DJG-6).

The Department finds that the Attorney General's curve provides a better mathematical fit to the Company's data, exhibiting an SSD of 0.0987, compared to the Company's curve, which has an SSD of 0.8299 (Exhs. NG-NWA-3, at 116 (Rev.); NG-NWA-Rebuttal-1, at 30; AG-DJG-1, at 22; AG-DJG-11, at 2). In a review of industry data for Account 369.10, a majority of utilities use an ASL of 56 years, with more than a third using curves with ASLs of 60 years or longer, suggesting both curves are within the range of reasonableness (Exh. AG 2-18, Att.). A detailed look at the observed retirement data of this account, however, indicates that approximately 70 percent of assets (dollar value) in this account survive to 60 years of age, suggesting a longer ASL than 55 years is warranted (Exhs. NG-NWA-3, at 116, 118 (Rev.); AG-DJG-11, at 2). Based on the statistical and visual curve fitting, the available industry data, and the percentage of assets surviving up to 60 years of age, the Department finds the Attorney General's proposed curve of 64-R2 is reasonable and appropriate. Thus, we approve an accrual rate of 3.72 percent for Account 369.10, Overhead Services which, when applied to the adjusted plant balance of $255,727,722, results in a depreciation expense of $9,513,071, representing a decrease of $2,889,724 (Exh. NG-RRP-2, Sch. 6, at 3 (Rev. 4)).

vi. Account 369.20 (Underground Services)

The current accrual rate for Account 369.20 is 3.64 percent, based on a 55-S1.5 curve (Exh. NG-NWA-4). The Company proposes to retain the current curve-life combination of 55-S1.5 with an accrual rate of 5.53 percent, while the Attorney General proposes a 63-R2.5 curve with an accrual rate of 4.33 percent (Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); NG-NWA-3 (Rev.) at 50; NG-NWA-4; AG-DJG-4; AG-DJG-5, at 1; AG-DJG-6).

The Department finds that the Attorney General's curve provides a better mathematical fit to the Company's data, exhibiting an SSD of 0.2047, compared to the Company's curve, which has an SSD of 1.3263 (Exh. AG-DJG-12, at 2). The Attorney General's curve also provides a better visual fit than the Company's curve (Exhs. NG- NWA-3, at 119 (Rev.); NG-NWA-Rebuttal-1, at 33; AG-DJG-1, at 24). While both proposed curves have similar tails and are within the range of industry ASLs, the Attorney General's curve provides a significantly better fit for the available retirement data, and aside from general claims regarding electrification, the Company has not provided persuasive evidence to deviate from its observed retirement experience (Exhs. NG-NWA-Rebuttal-1, at 33-34; AG-2-18, Att.). Therefore, the Department finds the Attorney General's proposed 63-R2.5 curve is reasonable and appropriate, and we approve an accrual rate of 4.33 percent for Account 369.20, Underground Services. When applied to the adjusted plant balance of $105,828,704, this produces an annual depreciation expense of $4,582,383, representing a decrease of $1,269,944 (Exhs. NG-RRP-2, Sch. 6, at 3 (Rev. 4); AG-DJG-1).

c. AMR/AMI Assets

As noted above, the Company proposes to remove all depreciation expense associated with meters (Account 370.10, Account 370.20, Account 370.30, Account 370.35) and to reflect those costs outside of base distribution rates in the AMIF, with costs to be fully recovered by the end of 2028 (Exhs. NG-RRP-1, at 67; NG-RRP-2, Sch. 6, at 3 (Rev. 4)). No intervenor commented on this proposal on brief. The Department finds this proposal is consistent with recent Department directives. D.P.U. 23-80/D.P.U. 23-81, at 198; D.P.U. 22-22, at 186-187. Accordingly, we approve this proposal.

4. Conclusion

Based on the analysis above, the Department finds that the appropriate depreciation expense reflects a combination of the Company's proposed curves and five curves proposed by the Attorney General. The adjustments to depreciation expense herein result in a total reduction of $15,957,875 to the Company's proposed depreciation expense of $197,426,248 (Exh. NG-RRP-2, Sch. 6, at 3 (Rev. 4)).[78] Therefore, the Department approves a depreciation expense of $181,468,373.[79]

C. Dues and Memberships

1. Introduction

National Grid maintains memberships in various industry and non-industry trade associations and organizations (Exhs. DPU 38-6; AG 1-56, Att.; AG 1-77, Att. (Supp.); AG 7-43, Att.; AG 7-44, Att. (Supp.)). National Grid states that dues related to memberships in

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[78] $5,139,286 + $4,323,018 + $2,335,903 + $2,889,724 + $1,269,944 = $15,957,875.

[79] $197,426,248 - $15,957,875 = $181,468,373.

non-industry, non-profit organizations support the Company in its operations (Exh. NG-RRP-Rebuttal-1, at 18). Further, the Company states that the various non-industry organizations provide benefits such as access to a diverse talent pipeline, increased involvement with community leaders, and access to climate resilience experts (Exh. NG-RRP-Rebuttal-1, at 19-20).[80]

During the test year, National Grid booked $914,653 for industry dues expense and $19,269 for non-industry dues expense, for a total test-year amount of $933,922 in dues and memberships expense (Exhs. DPU 38-7, Att.; AG 1-56, Att.; AG 1-77, Att. (Supp.); AG 7-43, Att.; AG 7-44, Att. (Supp.)). During the proceeding, the Company removed lobbying amounts from the dues expense and, if it could not determine the lobbying amount, the Company removed the total dues amount (Exhs. AG 7-43; AG 7-44 (Supp.)). The adjustments result in a final proposed industry dues expense amount of $906,111 and non-industry dues expense amount of $19,248, for a proposed total test-year amount of $925,359 in dues and memberships expense (Exhs. DPU 38-6; DPU 38-7, Att.). The Company states that its proposed test-year dues and memberships expenses are part of its residual O&M expenses and are not otherwise separately adjusted to reflect rate-year amounts (Exhs. NG-RRP-2, Sch. 27 (Rev. 4); NG-RRP-2, Sch. 30 (Rev. 4); DPU 38-8).

80 The Company provided explanations on the functions of each organization (Exh. AG 7-43 & Att.). National Grid also provided mission statements for three organizations, though only one is included in the Company's proposed test-year cost of service (Exhs. NG-RRP-Rebuttal-1, at 19; NG-RRP-2, Sch. 27 (Rev. 4); NG-RRP-2, Sch. 30 (Rev. 4); DPU 38-6; DPU 38-7, Att.; DPU 38-8).

2. Positions of the Parties

The Company asserts that its membership in non-industry organizations benefit both the Company and its customers because these organizations further the Company's efforts to hire a diverse workforce, engage with the community, increase the diversity of suppliers, and access climate resilience experts (Company Brief at 369, citing Exh. NG-RRP-Rebuttal-1, at 18-20). Finally, National Grid maintains that these organizations enable the Company to provide improved service to its customers (Company Brief at 369, citing Exh. NG-RRP-Rebuttal-1, at 20). No other party addressed this matter on brief.

3. Analysis and Findings

The Department has reviewed the record concerning the Company's industry and non-industry dues and memberships (Exhs. NG-RRP-Rebuttal-1, at 18-19; AG-JD-Surrebuttal-1, at 2-3; DPU 38-1 through DPU 38-9; AG 1-56, Att.; AG 1-77, Att. (Supp.); AG 7-43, Att.; AG 7-44 & Att. (Supp.); AG 15-1; AG 15-2). We find that the industry dues and memberships are supported by the record and that the Company appropriately removed lobbying expenses, as noted above. The Department accepts the Company's revised test-year industry dues and memberships amount of $906,111.

The Department requires that the Company demonstrate a link between non-industry dues and memberships and ratepayer benefits for the costs to be recoverable in rates. See, e.g., D.P.U. 92-111, at 127; Milford Water Company, D.P.U. 92-101, at 54 (1992); The Berkshire Gas Company, D.P.U. 90-121, at 151 (1990). Based on our review of the record, the Department finds a clear link between the Company's memberships in the non-industry organizations with two exceptions: New England Council Inc. and Leadership Council on Legal Diversity.

The Company states that its membership in New England Council Inc. promotes economic growth and high quality of life (Exh. AG 7-43, Att. at 5). The Company notes that the Leadership Council on Legal Diversity is composed of more than 400 corporate chief legal officers and law firm managing partners who have dedicated themselves to creating a diverse U.S. legal profession (Exh. AG 7-43, Att. at 6). While the Department recognizes that these memberships may help National Grid gain insight on issues relevant to its business, the Company has not demonstrated that there is a clear link between the memberships in these two non-industry organizations and meaningful customer benefits, or that these memberships are necessary to the provision of electric distribution service to customers. As such, the Department removes from the Company's cost-of-service, non-industry dues expense related to New England Council Inc. in the amount of $1,983 and non-industry dues expense related to Leadership Council on Legal Diversity in the amount of $1,531 (Exhs. DPU 38-6; DPU 38-7, Att.; AG 7-43, Att.). Accordingly, the Department reduces the Company's proposed cost of service by $3,514.

D. Service Company Rent/Information Technology Expense

1. Introduction

Service company rent expense represents charges billed to National Grid for capital costs incurred by NGSC to develop and own IT investments that will be used on a shared basis by the Company and other National Grid USA subsidiaries (Exh. NG-ITP-1, at 10). NGSC's Information Technology and Digital ("IT&D") organization's shared service and delivery functions provide focused oversight and transparency to enable better control and emphasize the delivery and cost of IT&D investments and products that serve the Company's customers (Exh. NG-ITP-1, at 8). The services provided by NGSC to the Company range from the support of critical electric distribution support systems to desktop applications (Exh. NG-ITP-1, at 7).[81] NGSC capitalized property includes IT investments, such as hardware, software, work management systems, customer support systems, and facilities, that are generally determined to benefit more than one company within the National Grid USA organization (Exhs. NG-ITP-1, at 6, 8, 10-11). The Company states that these services are necessary to enable the safe, reliable, and physically secure commercial operation of the Company (Exh. NG-ITP-1, at 7).

NGSC charges MECo and Nantucket Electric an allocated share of the amortization/depreciation expense and an associated return on IT and facilities assets, which is based on the Company's capital structure, ROE and, if applicable, property taxes (Exhs. NG-RRP-1, at 34; NG-RRP-2, Sch. 1, at 3; Sch. 17, at 4 (Rev. 4)). Cost allocation is determined by applying specific codes to assign expense based on cost causation and an allocation of costs to each operating company that derives a benefit from the investment (Exhs. NG-ITP-1, at 10; NG-ITP-3).

2. Company Proposal

During the test year, NGSC charged National Grid $69,984,905 in service company rents (Exhs. NG-RRP-1, at 35-36; NG-RRP-2, Sch. 17, at 1, 4 (Rev. 4)).[82] National Grid proposed a

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81 NGSC provides centralized corporate, administrative, customer, financial, information, security, procurement, legal, operational, safety, and regulatory services to the Company (Exhs. NG-RRP-1, at 34; AG 1-26, Att. 1, at 41-42).

82 Service company rent expense comprises four items: (1) depreciation, which represents the depreciation expense associated with each service company information system and

normalizing adjustment of negative $15,099,898 to restate the allocation based on a true-up of the return on and return of capital calculations for those charges, and an additional normalizing adjustment to reclassify deferred costs associated with other recovery mechanisms (Exhs. NG-RRP-1, at 34-36; NG-RRP-2, Sch. 17, at 4 (Rev. 4)). The sum of these adjustments resulted in a normalized test-year service company rent expense of $54,885,007 ($53,461,227 in IT projects and $1,423,780 in facilities and property tax) (Exhs. NG-RRP-1, at 35; NG-RRP-2, Sch. 17, at 1-4 (Rev. 4)). The Company then proposed a known and measurable adjustment to decrease its adjusted test year service company rent expense by $164,820 to account for ongoing depreciation and return on existing IT and facilities assets, as well as IT system additions and enhancements and facilities improvements in service by March 31, 2024 (Exhs. NG-RRP-1, at 35-36; NG-RRP-2, Sch. 17, at 3 (Rev. 4); WPs NG-RRP-6a (Rev. 4) through NG-RRP-6f (Rev. 4)). The adjustments result in a proposed rate-year service company rent expense of $54,720,187 ($53,233,722 in IT projects and $1,486,465 in facilities and property tax) (Exh. NG-RRP-2, Sch. 17, at 2 (Rev. 4)).

The Company's proposed rate-year service company rent expense includes $40,143,288 associated with 286 IT projects completed between April 1, 2019 and the end of the test year, March 31, 2023, and $13,090,434 associated with 62 IT projects completed after the end of the test year and through March 31, 2024 (Exhs. NG-ITP-1, at 6; NG-ITP-4, Att. 1; NG-ITP-5,

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facility project charged to the Company during the test year; (2) debt, which represents the allocation of the return component of the service company rent expense; (3) equity, which represents the allocation of the return component of the service company rent expense; and (4) property tax, which represents the personal property taxes paid by NGSC on the March 31, 2023 net book value of its Massachusetts assets (Exhs. NG-RRP-2, Sch. 17, at 4 (Rev. 4); AG 7-54).

Atts. 1, 3, 5; NG-RRP-2, Sch. 17, at 4 (Rev. 4)). The proposed rate-year service company rent expense also includes $1,383,490 associated with existing facilities, $33,433 associated with post-test-year facilities, and $69,542 associated with property taxes (Exh. NG-RRP-2, Sch. 17, at 4 (Rev. 4)). The Company states that it provided all necessary documentation to support the proposed cost recovery related to its IT projects, facilities expenses, and vendor costs (Exhs. NG-ITP-1, at 7, 11-17; NG-ITP-1 through NG-ITP-5; AG 1-19 (Supp.); AG 1-19 (Supp. 2); AG 1-19 (Supp. 3); AG 1-19 (Supp. 4)).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should require the Company, in future base distribution rate cases, to provide complete information for post-test-year IT projects with its initial filing (Attorney General Brief at 97-98). The Attorney General urges the Department to consider excluding post-test-year IT project documentation submitted after the initial filing because allowing the Company to supplement its post-test-year IT projects during the proceeding does not fairly balance the interests of all parties (Attorney General Brief at 97-98).

b. Company

National Grid argues that the Attorney General’s recommendation to require all IT project documentation in its initial filing is not practical and would negatively impact the Company (Company Brief at 301). The Company claims that its post-test-year IT additions are known and measurable, in service, benefiting customers, and the associated project documentation was submitted by April 5, 2024, allowing time for review prior to the evidentiary hearings in this proceeding (Company Brief at 301). The Company contends that denying post-test-year known and measurable expense changes would be tantamount to a disallowance of a substantial portion of the investment without any finding of imprudence (Company Brief at 302). Finally, National Grid asserts that most of the IT projects are associated with rent expense periods of five to seven years, which is much shorter than the Company's typical utility plant assets, and this fact combined with the rapidly changing technology landscape make it imperative that post-test-year known and measurable changes are included in rates so that the recovery of system costs remains aligned with the lifecycle of these projects (Company Brief at 301-302).

4. Analysis and Findings

The standard for the inclusion of IT expense is composed of three elements.[83] First, the investments underlying the IT expense must be 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, 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);

[83] 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.

see also D.P.U. 12-86, at 11 (Department must carefully scrutinize affiliate transactions because exercise of control and 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 seasonably amend their initial filings to include documentation associated with post-test-year investments, if applicable. D.P.U. 18-150, at 275. Finally, the Department stated that all additional supporting documentation provided through discovery should be produced in a timely fashion and no later than the close of discovery so that the Department and intervenors have sufficient time to review them prior to the evidentiary hearings. D.P.U. 18-150, at 275.

The Department has reviewed the testimony and supporting documentation for the Company's test-year and post-test-year IT projects and facilities, 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. NG-ITP-1 through NG-ITP-5; NG-RRP-2, Sch. 17 (Rev. 4); WPs NG-RRP-6a (Rev. 4) through NG-RRP-6f (Rev. 4); DPU 24-1 through DPU 24-4; DPU 51-1 through DPU 51-3; AG 1-19 & Supps.; AG 7-51; AG 7-53; AG 7-54; AG 7-56 through AG 7-58). The Department finds that the test-year and post-test-year IT projects and facilities are in-service, used and useful, the costs were prudently incurred, and the Company provided a reasonable explanation of the benefits to ratepayers (Exhs. NG-ITP-1 through NG-ITP-5; NG-RRP-2, Sch. 17 (Rev. 4); WPs NG-RRP-6a (Rev. 4) through NG-RRP-6f (Rev. 4); DPU 24-1 through DPU 24-4; DPU 51-1 through DPU 51-3; AG 1-19 & Supps.)). For example, customers benefit from the proposed IT investments because the systems are necessary for the provision of electric service to customers and they are provided more economically and efficiently within a cost-sharing framework (e.g., undertaken by NGSC on behalf of the operating companies on a shared basis) (Exhs. NG-RRP-1, at 11; NG-ITP-4, Att. 27; NG-JR-4, at 3; NG-RRP-Rebuttal-1, at 22). Further, we find that the test-year and post-test-year IT project and facilities costs were fairly allocated to National Grid based on the Company's cost allocation method (Exhs. NG-ITP-1, at 10-11; NG-ITP-3; NG-RRP-1, at 11). Additionally, the Company provided a summary of its IT long-term investment plan (Exhs. NG-ITP-1, at 11-12; NG-ITP-5, Att. 8).

The Attorney General recommends that the Department require the Company to submit all project documentation associated with post-test-year capital additions with its initial filing in future proceedings and consider excluding from consideration in the instant case the post-test-year IT&D project documentation supplemented after the Company's initial filing (Attorney General Brief at 97-98). 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. We see no reason to depart from this standard for future filings. Further, in the instant case, the Department issued a procedural schedule that set a reasonable deadline for the Company to provide final post-test-year IT&D project documentation and for the parties to conduct discovery on the documentation, all in advance of the evidentiary hearings. D.P.U. 23-150, Hearing Officer Memorandum at 2 (December 12, 2023). No party filed an objection to the procedural schedule.[84] The Department finds that all parties had sufficient opportunity to review project documentation, issue discovery, conduct meaningful cross-examination at the evidentiary hearings, and present any objections to cost recovery for Department consideration associated with the post-test-year IT&D projects. Based on these considerations, the Department rejects the Attorney General's recommendation to exclude the post-test-year IT&D project documentation.

Finally, consistent with Department precedent, for the return component of the Company's IT project and facilities expenses, the Department calculates the weighted average

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84 The Department's procedural schedule set the following deadlines: (1) April 5, 2024, for the Company to provide final documentation supporting post-test-year IT investments; (2) April 12, 2024, for the parties to issue discovery on the post-test-year documentation; and (3) April 22, 2024, for the Company to respond to the discovery. D.P.U. 23-150, Hearing Officer Memorandum at 2-3. The Department issued a subsequent procedural notice with the same deadlines. D.P.U. 23-150, Procedural Notice at 2-3 (January 18, 2024). No party objected to the deadlines in the procedural notice. Evidentiary hearings began on May 6, 2024 (Tr. 1, at 1).

cost of capital ("WACC") using the capital structure and ROE approved in this Order. D.P.U. 22-22, at 228; 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 7.09 percent and a pretax WACC of 8.95 percent. Application of the Company's approved pre-tax WACC to NGSC's allocation of service company rent expense results in a decrease of $1,070,934 to the proposed rate-year service company rent expense (Exhs. NG-RRP-2, Sch. 17, at 2 (Rev. 4); WP NG-RRP-6, Service Company Rents (Rev. 4)). Accordingly, the Department decreases the Company's proposed service company rent expense by $1,070,934 from the Company's proposed amount of $54,720,187 to $53,649,253.

E. Property Tax Expense

1. Introduction

During the test year, the Company booked $81,809,885 in property tax expense (Exh. NG-RRP-2, Sch. 7, at 1 (Rev. 4)). The Company normalized the test-year property tax expense by removing $1,591,590 of property taxes[85] to derive a normalized test-year property tax amount of $80,218,296 (Exhs. NG-RRP-1, at 68; NG-RRP-2, Sch. 7, at 1, 3 (Rev. 4)). Next, the Company proposed to adjust the normalized test-year property tax expense by $8,551,454, to

85 The Company removed $383,567 recovered through the Grid Modernization Factor and $1,208,023 associated with existing meters that the Company proposed to recover through its AMI reconciling mechanism (Exhs. NG-RRP-1, at 68; NG-RRP-2, Sch. 7, at 1, 3 (Rev. 4)).

reflect the proposed rate-year property tax expense of $88,769,750 (Exhs. NG-RRP-1, at 68-69; NG-RRP-2, Sch. 7, at 2 (Rev. 4)).[86]

The Company calculated its rate-year property tax expense by multiplying the property tax base for each municipality by the mill rate for that municipality in the 2023-2024 fiscal year (Exh. NG-RRP-1, at 68-76; NG-RRP-2, Sch. 7, at 4-8 (Rev. 4)). The property tax base is the sum of the real property and the personal property (Exhs. NG-RRP-1, at 72; NG-RRP-2, Sch. 7, at 4-8 (Rev. 4)). The real property value component of the property tax base for each municipality is based on the full and fair market value of all real estate established as of January 1, 2023 (Exhs. NG-RRP-1, at 71; WP NG-RRP-10a). The personal property value component is based on the valuation of Company-owned assets using the hybrid replacement cost new less depreciation/net book value ("RCNLD/NBV") method adopted by the municipalities (Exh. NG-RRP-1, at 71).[87] Using the most recent Forms of List ("FOL") for each municipality and the information contained in the most recent tax bills, the Company determined the adjusted RCNLD/NBV valuation, excluding CWIP, for each municipality (Exhs. NG-RRP-1, at 75; NG-RRP-2, Sch. 7, at 9-13 (Rev. 4)).

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86 In the initial filing the Company reported a test-year property tax expense of $81,809,885, made a normalizing adjustment of negative $1,598,323, and made a known and measurable adjustment of $3,263,170 to reflect the initially proposed rate-year property tax expense (Exhs. NG-RPP-1, at 68; NG-RRP-2, Sch. 7, at 1, 2).

87 In 2019, the Massachusetts Department of Revenue issued a decision that municipalities may adopt a hybrid valuation approach, in which property values are based 50 percent on RCNLD and 50 percent on NBV (Exh. NG-RRP-1, at 65). See also Massachusetts Department of Revenue's Division of Local Services, Bureau of Municipal Finance Law, Local Finance Opinion 2019-1 (March 26, 2019).

The Company received $2,330,746 in property tax abatements between August 2020 and September 2023 (Exh. AG 1-85). During the test year, the Company received one abatement from the Town of Grafton in the amount of $4,901 in November 2022 (Exh. AG 1-85). The Company does not propose to adjust its rate-year property tax expense to account for abatements (Exh. NG-RRP-2, Sch. 7 (Rev. 4)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that it is longstanding Department precedent to use property tax abatements to reduce the pro forma cost of service (Attorney General Brief 117, citing D.P.U. 09-39, at 240, 244-245; D.P.U. 88-67 (Phase I) at 166; D.P.U. 1720, at 80; Attorney General Reply Brief at 27). Therefore, she maintains that the Company should be required to return to ratepayers $2,330,746 of property tax abatements received during the last four years (Attorney General Brief 117, citing Exh. AG 1-85; Attorney General Reply Brief at 27). The Attorney General recommends a reduction of $466,149 based on her calculated five-year amortization to reflect the term of the Company's proposed PBR-O plan (Attorney General Brief 117).

The Attorney General rejects any notion that the abatements may be associated with property tax valuations in periods prior to the Company's current PBR plan, and she argues that there is no evidence to support this proposition, as the Company provides only a total abatement amount through 2020 (Attorney General Reply Brief at 27, citing Exh. AG 1-85). Moreover, she contends that because the test year in the Company's last base distribution rate case was 2017, the existing PBR plan contains abatements associated with tax periods 2017-2020 (Attorney

General Reply Brief at 27, citing D.P.U. 18-150, at 1). Further, the Attorney General maintains that fairness dictates that returned abatements should receive the same treatment, regardless of the tax periods for which the inappropriate valuations were made (Attorney General Reply Brief at 28).

The Attorney General also dismisses any suggestion that tax abatement cannot be returned because property tax expense is fixed in base distribution rates (Attorney General Reply Brief at 28). According to the Attorney General, the Company's property tax expense is not a fixed amount, as the current PBR plan provides increases to property tax through the inflation and exogenous cost components, and previously the Company received annual increases in rates for property taxes through its capital tracker (Attorney General Reply Brief at 27, citing D.P.U. 18-150, at 54-74; D.P.U. 09-39, at 71-84).

b. Company

National Grid argues that its approach to calculating its rate-year property tax expense was approved by the Department in D.P.U. 18-150, which uses a method to establish rate-year property tax expense that incorporates more up-to-date information and thus reflects a more reliable representation of the revenue requirement related to property taxes (Company Brief at 327, citing Exh. NG-RRP-1, at 74). The Company contends that there is no Department precedent to support the Attorney General's claim that tax abatements should be used to reduce the proposed cost of service in this case (Company Brief at 368; Company Reply Brief at 50). Rather, the Company contends that the Attorney General's recommendation would be inconsistent with the Department's longstanding practice to reflect a utility's most recently received property tax bills (in the instant case, the Company's fiscal year 2024 tax bills) in the rate year in the revenue requirement (Company Brief at 324-325, citing D.P.U. 15-155, at 213; D.P.U. 15-80/D.P.U. 15-81, at 166; D.P.U. 14-150, at 209; D.P.U. 12-25, at 329; New England Gas Company, D.P.U. 08-35, at 150 (2009); D.P.U. 96-50 (Phase I) at 109; Colonial Gas Company, D.P.U. 84-94, at 19 (1982); Company Reply Brief at 50-51).

Further, the Company asserts that the majority of the property tax abatements (totaling $2,078,977) is due to inappropriate valuations from the City of Worcester in the 2012-2013 through 2019-2020 tax years (Company Brief at 368, citing Exh. AG 1-85). Of these contested tax years, National Grid maintains that only nine months occurred during the current PBR plan, and prior to that, the Company recovered a fixed, rate-year amount of property tax and, therefore, was unable to collect any "under-recovery" of property tax expense between base distribution rate cases (Company Brief at 368). Thus, the Company asserts that it would be inappropriate to reduce its cost of service in this case to account for those older tax abatements (Company Brief at 368; Company Reply Brief at 51).

3. Analysis and Findings

The Department's current policy to determine property tax expense is based on the Company's most recent FOL submission to the Massachusetts Department of Revenue, in conjunction with information contained in the most recent tax bills. D.P.U. 17-170, at 174. Because they are considered verifiable, non-controversial evidence, the Department holds the record open in a proceeding to receive from the utility the most current tax bills issued by cities and towns. D.P.U. 14-150, at 209; D.P.U. 88-67 (Phase I) at 165-166; D.P.U. 84-94, at 19.

National Grid's rate-year property tax expense is based on the January 1, 2023 assessed values of the Company's real property, for the 2023 to 2024 tax year, and the valuation of

Company-owned assets using the RCNLD/NBV method adopted by the municipalities (Exhs. NG-RRP-1, at 68-76; NG-RRP-2, Sch. 7, at 4-8 (Rev. 4); WP NG-RRP-10a; DPU 27-7). The Department finds that the Company's method of calculating property tax expense based on the RCNLD/NBV method produces a nonspeculative, reliable measure of the Company's rate-year tax expense, satisfies the Department's known and measurable standard, and is in line with Department precedent, subject to our findings below. D.P.U. 17-05, at 250-251; D.P.U. 12-86, at 243-245; D.P.U. 95-118, at 148. Further, we conclude that the Company has provided appropriate documentation to support its proposed level of property tax expense (Exhs. NG-RRP-1, at 68-76; NG-RRP-2, Sch. 7 (Rev. 4); WP NG-RRP-10a through WP NG-RRP-10j (Rev. 4)).

The Department treats any property tax abatements received during the test-year on a cash basis to reduce property tax expense. D.P.U. 09-39, at 244-245; D.P.U. 88-67 (Phase I) at 166; D.P.U. 1720, at 80. Abatements received on a cash basis after the test year are not reflected in the cost of service unless they are so extraordinary in amount that their exclusion results in an unrepresentative level of property tax expense in the cost of service. D.P.U. 88-67 (Phase I) at 166; D.P.U. 1720, at 80. See also Massachusetts Electric Company, D.P.U. 800 (1982); Boston Edison Company, D.P.U. 160 (1980): Manchester Electric Company, D.P.U. 20113 (1980); Boston Edison Company, D.P.U. 19991 (1979); Boston Gas Company, D.P.U. 19470 (1978); Boston Edison Company, D.P.U. 19300 (1978); Boston Edison Company, D.P.U. 18515 (1976). Accordingly, the Department rejects the Attorney General's recommendation to reduce the Company's property tax expense by the overall amount of tax abatements received over the last four years.

The record shows that the Company received one tax abatement in the test year from the Town of Grafton for $4,901 that was not accounted for in the requested property tax expense (Exhs. NG-RRP-2, Sch. 7 (Rev. 4); WP NG-RRP-10a; AG 1-85). The Department finds it appropriate to include this tax abatement and, thus, reduce the Company's proposed property tax expense. The Company received two post-test-year tax abatements, one from the City of Lowell and one from the Town of Billerica, totaling $198,826 that were not accounted for in the requested property tax expense (Exhs. NG-RRP-2, Sch. 7 (Rev. 4); WP NG-RRP-10a; AG 1-85). Based on the normalized test-year property tax expense of $80,218,296, the Department finds that the post-test-year tax abatements are not so extraordinary that their exclusion from the cost of service would result in an unrepresentative level of property tax expense (Exhs. NG-RRP-1, at 68; NG-RRP-2, Sch. 7, at 1, 3 (Rev. 4)). D.P.U. 88-67 (Phase I) at 166; D.P.U. 1720, at 80. As such, these tax abatements shall not reduce the Company's proposed cost of service. Based on the above findings, the Department approves a pro forma adjustment to test-year property tax expense of $8,551,454, less a reduction of $4,901 for test-year abatements, which results in a final property tax expense of $88,764,849 (Exhs. NG-RRP-2, Sch. 7, at 2 (Rev. 4); NG-RRP-7, at 10 (Rev. 4)).

F. Customer Account Management Proposal

1. Introduction

The Company proposes to create a new customer account management function to support certain customers with the clean energy transition, including large end-use customers, national accounts, municipal and government accounts, property managers, real estate developers, and DG developers (Exh. NG-CP-1, at 46-47). National Grid states that it plans to hire 23 FTEs to support its new customer account management function (Exhs. NG-CP-1, at 47; NG-RRP-2, Sch. 43, at 5).[88]

National Grid initially proposed to include $1,981,315 in its cost of service for the Company's allocated costs related to the planned 23 post-test-year FTEs (Exhs. NG-CP-1, at 48; NG-RRP-2, Sch. 43, at 2-4).[89] During the proceeding, the Company hired 14 of the proposed 23 FTEs, eight of whom were external hires, and now proposes to include $630,388 in costs related to those eight FTEs (Exhs. NG-CP-Rebuttal-1, at 39; NG-RRP-2, Sch. 43, at 2-5 (Rev. 4); RR-AG-18).[90] The Company's revised cost of service for these FTEs consists of: (1) $485,372 for payroll expense; (2) $41,828 for healthcare expense; (3) $2,877 for group life insurance expense; (4) $28,977 for 401(k) expense; (5) $36,508 for payroll taxes, (6) $22,090 for employee expenses; and (7) $12,736 for transportation expense (Exh. NG-RRP-2, Sch. 43, at 3 (Rev. 4)).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should disallow the $630,388 increase related to the eight employees hired after the test year (Attorney General Brief at 97). The Attorney General asserts that the Department determines payroll expense based on test-year

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88 The 23 FTEs are hired by NGSC with a portion of the costs allocated to the Company (Exh. NG-RRP-2, Sch. 43, at 3 (Rev. 4)).

89 Of the 23 FTEs, the Company expects to be allocated 15.24 FTEs (Exh. NG-RRP-2, Sch. 43, at 5).

90 The costs for the six internal FTEs are included in the Company's payroll expenses. Of the eight external hires, the Company is allocated 4.72 FTEs (Exh. NG-RRP-2, Sch. 43, at 5 (Rev. 4)).

employee levels and allows increases only if there has been a significant post-test-year change in the number of employees that falls outside the normal ebb and flow of a company's workforce (Attorney General Brief at 97, citing D.P.U. 09-39, at 136-137; D.P.U. 90-121, at 80-81). The Attorney General contends that in the instant proceeding National Grid has not demonstrated a significant post-test-year change in employee levels that falls outside the normal ebb and flow of the Company's workforce (Attorney General Brief at 97; Attorney General Reply Brief at 29-30).

The Attorney General takes issue with the Company's assertion that the Department should evaluate the new employees in the context of the new customer account management function (Attorney General Reply Brief at 30). The Attorney General maintains that National Grid's position is inconsistent with Department precedent, which evaluates staffing changes in the context of total employees (Attorney General Reply Brief at 30-31, citing D.P.U. 17-170, at 77).

b. TEC/PowerOptions

TEC/PowerOptions argues that the Department should approve the Company's proposal to include costs related to the post-test-year hires for its customer account management function (TEC/PowerOptions Brief at 11-12; TEC/PowerOptions Reply Brief at 6). TEC/PowerOptions maintains that the Company has adequately demonstrated that the costs of these hires are known and measurable and outside the normal ebb and flow (TEC/PowerOptions Brief at 12-13, citing Exh. NG-CP-Rebuttal-1, at 39; TEC/PowerOptions Reply Brief at 6). TEC/PowerOptions asserts that the Company's eight external hires represent a 57 percent increase in customer account management staffing and therefore do not fall under the normal ebb and flow of staffing levels as the Attorney General argues (TEC/PowerOptions Brief at 12-13, citing Exhs. NG-CP-Rebuttal-1, at 39; AG-JD-Surrebuttal-1, at 2).

In addition, TEC/PowerOptions maintains that it has conducted surveys of its members and has found widespread discontent about National Grid's repeated billing errors, incorrect late fees, lack of internal Company communication across departments, and general poor responsiveness (TEC/PowerOptions Brief at 12, citing Exhs. NG-CP-1, at 48; TEC/PO-JDB/AN-1, at 31-32). TEC/PowerOptions contends that the Company's creation of the customer account management function will alleviate these problems and are an overdue solution to a longstanding problem (TEC/PowerOptions Brief at 12, citing Exh. NG-CP-Rebuttal-1, at 41; TEC/PowerOptions Reply Brief at 6). TEC/PowerOptions suggests that the Department implement a reporting schedule to ensure that these hires are effective at their goals of improving communications and solving problems for end-user customers (TEC/PowerOptions Reply Brief at 6).

c. Company

The Company argues that the Department should approve the costs of its post-test-year hires to implement its customer account management function (Company Brief at 466; Company Reply Brief at 78). National Grid contends that its need for these hires derives from two rationales: (1) large customers have requested more proactive and detailed assistance with the energy transition; and (2) the Company's internal audit suggested that it had not dedicated enough employees to staffing such large accounts (Company Brief at 466-467; Company Reply Brief at 80-81). The Company maintains that these post-test-year hires will provide myriad customer benefits, including (1) improving focus through developing strategic account plans with customers, (2) increasing engagement with customers regarding the energy transition's environmental and system benefits, and (3) improving customer satisfaction by accelerating timelines and reducing customer wait times (Company Brief at 468; Company Reply Brief at 80-81).

National Grid argues that its proposal meets the Department's standard for including post-test-year employees in its cost of service because they are both known and measurable and are outside the Company's normal ebb and flow of hiring (Company Brief at 468-469; Company Reply Brief at 78-79). The Company contends that it is requesting only costs related to the eight external hires that were hired prior to the close of the record, which it asserts meets the Department's known and measurable standard (Company Brief at 468; Company Reply Brief at 78). The Company also argues that its proposal meets the Department's standard for post-test-year hires that are outside the normal ebb and flow of hiring because these additional hires represent a 100 percent increase in FTEs over existing account management staff and support a one-off permanent change to National Grid's organizational structure (Company Brief at 469; Company Reply Brief at 78-79). The Company takes issue with the Attorney General's argument that the Department disallow recovery of these costs, averring that the Attorney General's own witness advocated for cost recovery only with respect to employees hired before the close of the record, which the Company states it is doing by only including costs related to eight FTEs (Company Brief at 470; Company Reply Brief at 78). National Grid further disagrees with the Attorney General's contention that the increase in employees should be weighed against the Company's total headcount, arguing that the Department has allowed adjustments for post-test-year changes to employee levels when they are associated with a permanent change to a company's structure or organization (Company Reply Brief at 79, citing D.T.E. 01-56, at 57; Massachusetts-American Water Company, D.P.U. 88-172, at 12 (1989); D.P.U. 19-120, at 242).

The Company also argues that its customer account management proposal represents new program activities that were not part of the test year used to set base distribution rates and were not associated with the continuation of normal operations, thereby meeting the Department's post-test-year staffing change standard (Company Reply Brief at 79-80). Finally, National Grid argues that these FTE hires are necessary now because if the Department approves its CPI Plan proposal as filed, the Company is committing to a five-year stay-out and denying recovery of these costs would impede the Company's ability to staff projects that enable the energy transition and fulfill the Commonwealth's clean energy goals (Company Reply Brief at 82-83).

3. Analysis and Findings

The Department has recognized that employee levels routinely fluctuate because of retirements, resignations, hirings, terminations, and other factors. D.P.U. 88-172, at 12; D.P.U. 1270/1414, at 16-17. In recognition of this variability, the Department generally determines payroll expense based on test-year employee levels, unless there has been a significant post-test-year change in the number of employees that falls outside the normal ebb and flow of a company's workforce. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12.

The Department first considers whether the Company has demonstrated that the costs related to the post-test-year FTEs are known and measurable. D.P.U. 17-170, at 79. As of the close of the record on this issue, the Company had hired 14 of the 23 post-test-year FTEs, eight of whom were external hires (Exh. NG-CP-Rebuttal-1, at 39). The Company provided the allocated costs associated with eight external hires (Exhs. NG-RRP-2, Sch. 43, at 2-5 (Rev. 4); NG-RRP-7, Sch. 2c (Rev. 4)). The Department finds that the costs associated with these eight FTEs are known and measurable.

Next, we consider whether the eight post-test-year FTEs the costs for which we found to be known and measurable fall outside the normal ebb and flow of the Company's workforce. D.P.U. 90-121, at 80-81; D.P.U. 88-172, at 12. Consistent with past practice, we measure the proposed post-test-year increase in employee count against the complement of test-year-end National Grid and NGSC employees. See, e.g., D.P.U. 20-120, at 195-196; D.P.U. 19-120, at 240; D.P.U. 17-170, at 80 & n.51. At the end of the test year, there were 1,226.5 National Grid FTEs and 6,979 NGSC FTEs for a total of 8,205.5 FTEs (Exh. AG 1-44, Att. (Supp.)). When comparing the 14 FTEs to the test-year-end total employee count for National Grid and NGSC of 8,205.5 FTEs, the increase is less than 0.2 percent. As a result, the impact of 14 FTEs is not a significant change for National Grid.[91] The Department finds that neither the number of proposed FTEs nor the percentage change in employee levels is outside the normal ebb and flow of hirings, retirements, resignations, or departures.

The Company that because it is making a permanent change to its structure, the costs should be allowed (Company Reply Brief at 79). While we recognize the importance of the Company supporting customers with the clean energy transition, the Department is not convinced that the costs are outside of the normal ebb and flow of employee levels. For example, of the 14 employees hired for this new service, six were internal hires, thus

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91 Our decision would not be different if we considered all 23 proposed post-test-year FTEs instead of the 14 post-test-year FTEs.

demonstrating the Company's ability to shift internal candidates to customer account management positions (Exhs. NG-CP-Rebuttal-1, at 39; NG-RRP-2, Sch. 43, at 2-5 (Rev. 4); RR-AG-18). Further, the cases cited by National Grid as precedent are inapposite. D.P.U. 19-120, at 242 (costs allowed for post-test-year employees directly associated with additional public safety work resulting from the Merrimack Valley incident[92]); D.P.U. 01-56, at 57 (Department removing costs where positions for two officers eliminated after acquisition of utility); D.P.U. 88-172, at 12 (Department allowed removal of costs for four positions after sale of utility resulted in reorganization change). Therefore, we disallow the allocated costs for the eight FTEs in the Company's cost of service. Accordingly, we reduce the Company's proposed cost of service by $630,388.

G. OSHA Penalty

1. Introduction

During the test year, the Company was cited by OSHA for a violation that resulted in a fine of $43,506 (Exh. AG 1-83, at 1). The Attorney General maintains that the Department excludes fines and penalties of all types from cost of service as a matter of public policy, including SQ payments (Attorney General Brief at 116, citing D.T.E. 03-40, at 261-262; D.P.U. 88-67 (Phase I), at 142-143). On this basis, the Attorney General urges the Department to reduce the Company's cost of service by $43,506 (Attorney General Brief at 117). National

[92] On September 13, 2018, Bay State Gas Company, now Eversource Gas Company of Massachusetts, experienced an over-pressurization of its low-pressure distribution system, which allowed gas from a high-pressure distribution system to enter the low-pressure distribution system resulting in the damage or destruction of 131 homes and businesses, the hospitalization of 22 individuals, and the death of one person. D.P.U. 19-120, at 45 n.31.

Grid contends that it books penalties to Account 426.3, which is excluded from the Company's cost of service (Company Brief at 367, citing Exh. AG-1-83). On this basis, the Company concludes that no further action is required to remove the $43,506 OSHA penalty (Company Brief at 367).

2. Analysis and Findings

The Department excludes fines and penalties of all types from cost of service as a matter of public policy. D.P.U. 12-86, at 165-166; D.P.U. 93-60, at 110; D.P.U. 88-67 (Phase I), at 142-143; D.P.U. 87-228, at 18-19; Nantucket Electric Company, D.P.U. 1530, at 26 (1983); Blackstone Gas Company, D.P.U. 19830/19980, at 10 (1979). Similarly, payments associated with customer service guarantees are excluded from cost of service. D.T.E. 03-40, at 261-262.

Electric utilities are required to book fines and penalties to Account 426.3, Penalties. 18 C.F.R. Part 101, Account 426.3; 220 CMR 51.01(1). National Grid appropriately books fines and penalties to Account 426.3 (Exh. AG 1-34, Att. 3, at 60). The Department has examined the Company's revenue requirement calculations and concludes that National Grid's proposed cost of service does not include Account 426.3-related expenses. The Department is satisfied that the Company has properly excluded the $43,506 OSHA fine from its cost of service (Exhs. AG 1-83, at 1; AG 28-29). D.T.E. 05-27, at 237. Therefore, no further adjustment is required.

H. Legal Settlement Payment

1. Introduction

During the test year, MECo booked $20,864,723 and Nantucket Electric booked $253,165 to Account 580, Operation Supervision and Engineering Expense (Exh. WP-NG-RRP-1a at 6, 11, 14 (Rev. 4)). Of this amount, a portion represented a legal settlement paid by both companies (Exh. DPU 2-4). The Company sought confidential treatment of the actual payment.

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the confidential settlement payment should be excluded from the Company's proposed cost of service (Attorney General Brief at 115, citing Exh. DPU 2-4). In support of her position, the Attorney General notes that while National Grid typically books settlement payments to Account 923, Outside Services Expense, the settlement payment in question was booked to Account 580 (Attorney General Brief at 115, citing Exh. NG-RRP-Rebuttal-1, at 15-17; Attorney General Reply Brief at 26). She argues that National Grid did not represent that its use of Account 580 to record the payment was in error and that the Company failed to offer any reason as to why this particular settlement was booked to this particular account (Attorney General Brief at 115, citing Exh. NG-RRP-Rebuttal-1, at 15-17; Attorney General Reply Brief at 26). The Attorney General maintains that the Company's decision to book the settlement to Account 580 suggests that this type of payment was unusual and did not constitute a normal or recurring expense (Attorney General Brief at 115-116, citing D.P.U. 20-120, at 274; Attorney General Reply Brief at 26).

b. Company

National Grid contends that an increase in expenses booked to Account 580 in the same quarter from one year to the next does not provide an adequate basis to determine the Company's level of recurring costs (Company Brief at 365, citing Exh. DPU 2-5).[93] The Company argues that it routinely incurs costs related to legal proceedings that result in settlements, and that the costs of these settlements are reasonable for inclusion in cost of service (Company Brief at 365; Company Reply Brief at 50). National Grid further maintains that while the costs of those settlements are usually booked to Account 923, Outsides Services Employed, a review of the Company's legal settlement costs from the last four years indicates that costs associated with legal settlements are routinely incurred and booked to various O&M expense accounts (Company Brief at 365, 366; Company Reply Brief at 50, citing Exh. NG-RRP-Rebuttal-1, at 16). Therefore, National Grid asserts that the Department should reject the Attorney General's recommendation to reduce the Company's test-year Account 580 expense (Company Brief at 365; Company Reply Brief at 50).

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.

Comparisons of quarter-to-quarter expense activities in different years are valuable in assessing the reliability of a company's selected test year and assist in identifying account activities that warrant closer review. D.P.U. 20-120, at 14-17. As discussed in Section III.B.

93 The relevant exhibit is Exhibit DPU 2-4; the Company's citation to Exhibit DPU 2-5 appears to be a typographical error.

above, the Department has accepted National Grid's proposed test year ending on March 31, 2023. In doing so, the Department noted that to the extent any test-year revenues and expenses are found to be unrepresentative or unreasonable, the Department will consider the appropriate ratemaking treatment in the respective sections of this Order.

Account 580 encompasses labor costs and expenses incurred in the general supervision and direction of the distribution system. 18 C.F.R. Part 101, Account 580; 220 CMR 51.01(1). While the majority of National Grid's settlement payments in recent years have been booked to Account 923, Outsides Services Employed, the Company also books settlement payments to other O&M expense accounts, including Account 580 (Exh. NG-RRP-Rebuttal-1, at 16; Tr. 2, at 283-284; Tr. 10, at 1287-1288). The Company determines the specific account used to book settlement payments based on its evaluation of the underlying cost causation (Tr. 2, at 283-284). Neither the FERC chart of accounts for electric companies nor the Department's accounting regulations requires that settlement payments be booked exclusively to Account 923. 18 C.F.R. Part 101, Account 923; 220 CMR 51.01(1); 220 CMR 50.00.

During fiscal year 2023 (i.e., the test year), National Grid booked $3,232,413 in legal settlement payments, recorded to 17 operation, maintenance, and general accounts (Exh. NG-RRP-Rebuttal-1, at 16-17). In comparison, the Company booked $3,199,018 in legal settlement payments to 14 accounts during fiscal year 2020, $2,032,078 in legal settlement payments to twelve accounts during fiscal year 2021, and $3,263,472 in legal settlement payments booked to twelve accounts during fiscal year 2022 (Exh. NG-RRP-Rebuttal-1, at 17). Although settlement payments made during fiscal year 2021 were considerably lower than those made in other years, the Department attributes this to a likely decrease in overall litigation-related activities during the COVID-19 pandemic, with its attendant disruptions to the Company, its vendors, and its customers. D.P.U. 22-22, at 8-9. There is no evidence that the lower level of payments made during fiscal year 2021 signify a particular trend in the Company's pattern of settlement payments.

Civil suits can be brought for a wide variety of reasons, limited only by the adeptness of an aggrieved party's counsel in identifying a cause of action. Given National Grid's policy of booking settlement payments based on cost causation, it thus follows that individual settlement payments and the accounts to which those payments are booked will inevitably vary from year to year. The Department has examined the pattern of settlement payments by account. There were significant increases in settlement payments booked to Accounts 580, 583, 903, 910, 911, and 920 versus payments recorded to these accounts in prior years (Exh. NG-RRP-Rebuttal-1, at 16).[94] Conversely, there were significant decreases in settlement payments booked to Accounts 588, 923, and 931 versus payments recorded to these accounts in prior fiscal years (Exh. NG-RRP-Rebuttal-1, at 16-17). In the case of Account 580, settlement payments booked to this account previously ranged from a credit of $35,532 during fiscal year 2021 to $59,462 during fiscal year 2020, versus $378,025 during the test year (Exh. NG-RRP-Rebuttal-1, at 16).

While an increase in account activity does not in itself warrant a finding that a particular expense is unrepresentative, the Department finds otherwise in this situation. As an initial

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94 While Account 930 also exhibited an increase in test-year settlement payments versus those recorded in recent years, the negative amounts recorded suggest the recording of various adjustments related to prior years (Exh. NG-RRP-Rebuttal-1, at 17). The Department has therefore not considered Account 930 settlement activity in its payment analysis.

matter, the fact that a settlement payment was made in the amount sought for confidential treatment is at odds with National Grid's representation that no judgments or settlements in excess of $50,000 were booked for MECo during the test year, and that no judgments or settlements were booked for Nantucket Electric during that same period (Exhs. DPU 2-4; AG 1-79 & Att.).[95] The Department is also unable to reconcile the amount of the settlement payment at issue with the other settlement and judgment payments itemized in the record (Exh. AG 1-79). Moreover, National Grid's reticence to explain the settlement payment, even when challenged by the Attorney General, contrasts with the level of detail provided by the Company to explain other account variances (Exhs. DPU 2-4; DPU 2-5; DPU 2-6; DPU 2-7; DPU 2-8; DPU 2-9; DPU 2-10; DPU 2-11; DPU 2-12; NG-RRP-Rebuttal-1, at 16). On this basis, the Department finds that the Company has failed to demonstrate that the settlement payment at issue is representative of the normal ebb and flow of settlement payments incurred by the Company. D.P.U. 11-01/D.P.U. 11-02, at 345-346; D.P.U. 08-35, at 120-125. Therefore, the Department reduces the Company's proposed Account 580 expense.

The Department will not base the disallowance on the actual settlement payment because of the confidential nature of the settlement payment. Moreover, some level of settlement

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95 In relevant part, the Attorney General's information request stated: "Please provide in list form the details of all judgments and/or settlements resulting from suits brought which involved National Grid, the Service Companies, and/or the Company as a defendant, which resulted in National Grid, the Service Companies, and/or the Company, in each of the years 2019, 2020, 2021, 2022, and the test year paying or agreeing to pay or being ordered to pay an amount in excess of $50,000" (Exh. AG 1-79). The Company responded, in pertinent part: No judgments or settlements in excess of $50,000 involving National Grid, the Service Company, and MECo were booked in the test year. There were no judgments or settlements related to Nantucket Electric Company during this time (Exh. AG 1-79).

payments can be expected to be booked to Account 580 on an ongoing basis (Exh. NG-RRP-Rebuttal-1, at 16). Instead, the Department will exclude from cost of service an amount deemed to be representative of the confidential settlement payment. In previous years, the Company booked an annual average of $18,098 in settlement payments to Account 580 (see Exh. NG-RRP-Rebuttal-1, at 16).[96] The test-year booking of $378,025, less the annual historical average of $18,098, produces an incremental $359,927 in settlement payments. The Department finds that the $359,927 is a reasonable proxy for the confidential settlement payment.[97] Therefore, the Department reduces the Company's proposed cost of service by $359,927.

I. Station Expense

1. Introduction

During the test year, MECo booked $4,357,481 and Nantucket Electric booked $73,595 to Account 582, Station Expense (Exh. WP-NG-RRP-1a, at 6, 11, 14 (Rev. 4)). Of this amount, $196,040 represented labor costs associated with what the Company described as increased maintenance and "damage repair" activities (Exh. DPU 2-5).[98]

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96 $18,098 represents the sum of $59,462 during fiscal year 2020, a negative $35,532 during fiscal year 2021, and $30,363 during fiscal year 2022, divided by three years (Exh. NG-RRP-Rebuttal-1, at 16).

97 National Grid was aware by February 2024 that the settlement payment was an issue in this proceeding and could have reasonably foreseen the possibility that the Department would exclude the payment from the Company's revenue requirement (Exhs. AG-LMK-1, at 10; NG-RRP-Rebuttal-1, at 15-16). The Department's resolution of this issue strikes a reasonable balance between the Company's desire to maintain the confidentiality of its litigation strategy and the Department's obligation to determine just and reasonable rates without resort to a confidential revenue requirement.

98 During the proceedings, the Company discovered that its test-year Account 582 expense had inadvertently included two years of rent payments associated with a rights-of-way

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the $196,040 in increased labor costs should be excluded from the Company's proposed cost of service (Attorney General Brief at 116, citing Exh. AG-LKM-2, Sch. 7). In support of her position, the Attorney General contends that although the Company attributed these costs to ongoing maintenance, the 50 percent increase in the test-year expense over the same period for the previous year indicates that the associated expenses are nonrecurring (Attorney General Brief at 115-116, citing D.P.U. 20-120, at 274).

b. Company

The Company argues that an increase in the same quarter from one year to the next does not provide an adequate basis to determine the Company's level of recurring costs (Company Brief at 366, citing Exh. DPU 2-5). Further, the Company contends that "damage repair" does not refer to a one-time repair, but rather to ongoing maintenance of the Company's infrastructure (Company Brief at 366-367). Additionally, the Company claims that while its level of routine maintenance expense booked to Account 582 for fiscal year 2022 was lower than in previous years, its test-year routine maintenance expense was consistent with historical trends (Company Brief at 367). Therefore, the Company asserts that the Department should reject the Attorney General's proposed reduction to station expenses of $196,040 (Company Brief at 367).

license agreement with the Massachusetts Bay Transportation Authority (Exh. DPU 2-5). The Company subsequently reduced its proposed cost of service by $243,637 representing one year of rent payments (Exhs. NG-RRP-2, Sch. 24, at 6 (Rev. 4); DPU 2-5).

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.

As noted above, comparisons of quarter-to-quarter expense activities in different years are valuable in assessing the reliability of a company's selected test year and assist in identifying account activities that warrant closer review. D.P.U. 20-120, at 14-17. In accepting National Grid's proposed test year ending on March 31, 2023, the Department noted that to the extent any test-year revenues and expenses are found to be unrepresentative or unreasonable, the Department will consider the appropriate ratemaking treatment in the respective sections of this Order.

Account 582 encompasses labor costs, materials used, and expenses incurred in the operation of distribution substations. 18 C.F.R. Part 101, Account 582; 220 CMR 51.01(1). During the test year, National Grid booked to this account $603,858 in expenses associated with what the Company identified as routine maintenance activities, as distinct from other expenses booked to Account 582 (Exh. NG-RRP-Rebuttal-1, at 18). In comparison, the Company booked $508,356 during fiscal year 2020, $515,628 during fiscal year 2021, and $376,040 during fiscal year 2022 in routine maintenance (Exh. NG-RRP-Rebuttal-1, at 18). Although some of the difference between expenses booked in fiscal year 2022 and the test year may be attributable to the timing of substation maintenance activities, maintenance cycles are routine and inherent with any type of complex equipment housed at multiple locations. There is no evidence that the Company gamed its maintenance activities to artificially inflate the test-year expense. Moreover, unlike the case with expenses incurred as the result of a single event such a fire or other incident, the expenses are consistent with repairs necessitated by normal wear on the Company's equipment (Tr. 2, at 285-286). Cf. Andrews Farm Water Company, D.P.U. 17-35-A at 55-56 (2018) (pump house explosion found to be extraordinary event); D.P.U. 85-270, at 150-153 (substation fire found to be nonrecurring expense); D.P.U. 1530, at 10-14 (turbocharger and piston repair found to be extraordinary nonrecurring expense). Finally, there is no evidence that the Company's damage repair activities are driven by deficient maintenance practices. The Department finds that National Grid's test-year maintenance activities are representative of the normal ebb and flow of account activity incurred by the Company. D.P.U. 11-01/D.P.U. 11-02, at 346-349; D.P.U. 10-114, at 250-255. Therefore, the Department declines to make any adjustment to the Company's Account 582 expenses.

J. Rate Case Expense

1. Introduction

Initially, the Company estimated that it would incur $2,619,156 in rate case expense (Exhs. NG-RRP-1, at 60; NG-RRP-2, Sch. 41, at 4). Based on its final invoices and projected costs to complete the compliance filing, the Company proposes a total rate case expense of $3,486,919 (Exh. DPU 17-23, Att. 10 (Supp. 3)).[99] National Grid's proposed rate case expense

[99] The Company provided invoices through July 30, 2024, while its final cost of service update includes costs through July 25, 2024. The Department relies on the actual invoices provided (compare Exh. DPU 17-23, Att. 10 (Supp. 3) with Exh. NG-RRP-2, Sch. 41, at 4 (Rev. 4)).

includes costs for legal representation and expert consulting costs related to the following issues: (1) PBR proposal; (2) compensation study; (3) revenue requirement; (4) allocated cost of service study ("ACOSS"); (5) depreciation study; (6) proposed ROE and capital structure; (7) strategic advisory services;[100] and (8) financial benchmarking study (Exhs. NG-RRP-2, Sch. 41, at 4 (Rev. 4); DPU 17-23, Att. 10 (Supp. 3)).[101]

The Company proposes to amortize the rate case expense over a five-year period consistent with the terms of its proposed CPI Plan (Exhs. NG-RRP-1, at 60; NG-RRP-2, Sch. 41, at 4 (Rev. 4)). Amortizing the Company's proposed rate case expense of $3,486,919 over five years produces an annual expense of $697,384 (Exh. DPU 17-23, Att. 10 (Supp. 3); see also Exh. NG-RRP-2, Sch. 41, at 4 (Rev. 4)).

2. Positions of the Parties

On brief, the Company summarizes its proposal regarding recovery of rate case expense and asserts that it provided voluminous evidence supporting the appropriateness of recovery (Company Brief at 318-319). No other party addressed this issue on brief.

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100 As discussed in detail below, the Company submitted invoices related to strategic advisory services provided by Apex Analytics but did not include Apex Analytics on its initial expert consulting list (Exhs. NG-RRP-2, Sch. 41, at 4; DPU 17-23, Att. 12 (Supp.)).

101 In its initial filing, the Company estimated expending $50,000 in IT-related testimony and miscellaneous costs such as printing (Exh. NG-RRP-2, Sch. 41, at 4). In its final cost of service update, the Company did not report expending any money on IT-related testimony or miscellaneous costs (Exhs. NG-RRP-2, Sch. 41, at 4 (Rev. 4); NG-DPU 17-23, Att. 10 (Supp. 3)).

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 has actually been incurred and, thus, is considered known and measurable. D.P.U. 10-114, at 219-220; D.P.U. 07-71, at 99; D.T.E. 05-27, at 157; D.T.E. 98-51, at 61-62. Second, such expenses must be reasonable, appropriate, and prudently incurred. D.P.U. 10-114, at 220; D.P.U. 09-30, at 226-227; D.P.U. 95-118, at 115-119.

The overall level of rate case expense among utilities has been, and remains, a matter of concern for the Department. D.P.U. 23-80/D.P.U. 23-81, at 234; D.P.U. 22-22, at 243-244; 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. 23-80/D.P.U. 23-81, at 234; D.P.U. 22-22, at 244; 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. 23-80/D.P.U. 23-81, at 234; 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 must be based on a request for proposal ("RFP") process that is fair, open, and transparent. D.P.U. 10-114, at 221, 224; D.P.U. 09-30, at 227-228; D.P.U. 07-71, at 99-100; D.T.E. 03-40, at 153. The timing of the RFP process should be appropriate to allow for a suitable field of potential service providers to provide complete bids and provide the company with sufficient time to evaluate the bids. D.P.U. 10-114, at 221; D.P.U. 10-55, at 342-343. Further, the RFP issued to solicit service providers must clearly identify the scope of work to be performed and the criteria for evaluation. D.P.U. 10-114, at 221-222; D.P.U. 10-55, at 343.

The Department does not seek to substitute its judgment for that of a petitioner in determining which service provider may be best suited to serve the petitioner's interests, and obtaining competitive bids does not mean that a company must necessarily retain the services of the lowest bidder regardless of its qualifications. D.P.U. 10-114, at 222; D.T.E. 03-40, at 153. The need to contain rate case expense, however, should be accorded a high priority in the review of bids received for rate 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 Request for Proposal Process

The Company seeks to include expenses associated with its (1) legal services, (2) PBR proposal, (3) compensation study, (4) revenue requirement; (5) ACOSS, (6) depreciation study, (7) proposed ROE and capital structure, (8) strategic advisory services, and (9) financial benchmarking study (Exhs. NG-RRP-2, Sch. 41, at 4 (Rev. 4); DPU 17-23, Att. 10 (Supp. 3)). National Grid did not use the competitive bidding process for three consultants: (1) Willis

Towers Watson (compensation study); (2) Concentric (financial benchmarking study);[102] and (3) Apex Analytics (strategic advisory services) (Exhs. DPU 17-5; DPU 17-23, Att. 12 (Supp.)).[103] The Department has determined that if a company decides to forgo the competitive bidding process, there must be an adequate justification for the company's decision to do so. D.P.U. 14-150, at 219; D.T.E. 01-56, at 76. Willis Towers Watson is a recognized authority in the field and provides compensation studies to all investor-owned Massachusetts utilities, including the Company. See, e.g., D.P.U. 17-05, at 132; D.P.U. 15-155, at 152-153; D.P.U. 15-80/D.P.U. 15-81, at 103, 108-109; D.P.U. 13-75, at 144-145. The Department finds that, in this instance, conducting a separate RFP for the sake of process, rather than to establish a field of potential bidders and establish price and non-price qualifications, would have been inefficient. D.P.U. 13-75, at 237; D.P.U. 12-25, at 192; D.P.U. 10-114, at 231; D.P.U. 09-30, at 232. Thus, we find that there is sufficient justification for the Company forgoing the competitive bidding process in selecting Willis Towers Watson as its compensation study provider, and we find that the Company's selection of this provider was reasonable.

We next turn to the financial benchmarking study performed by Concentric (Exhs. DPU 17-5; DPU 17-12). The Company stated that it engaged Concentric without conducting a competitive bidding process due to the quick turnaround needed to utilize the financial benchmarking study results in preparing its base rate distribution case for submission to

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102 Concentric also provided revenue requirement support in the proceeding and the scope of that work was competitively bid (Exh. DPU 17-5).

103 In its initial filing, National Grid included a witness to provide IT-related testimony for whom a competitive bidding process was not conducted. Ultimately, the Company did not include any costs for this witness.

the Department (Exh. DPU 17-5). A review of the invoices shows that the work was performed from April 2022 to September 2022, more than a year before the Company filed its base distribution rate case on November 16, 2023 (Exh. DPU 17-23, Att. 8). The decision of whether and when to file a base distribution rate case pursuant to G.L. c. 164, § 94, is within the discretion of the Company. D.P.U. 96-50 (Phase I) at 337-338; Commonwealth Electric Company, D.P.U. 88-135/151, at 28 (1989).[104] As such, the Company should have built in additional time to conduct the appropriate competitive bidding process. National Grid has been operating under a five-year PBR plan since October 1, 2019, that will expire on September 30, 2024. D.P.U. 18-150, at 75. The Company has had ample time over the last several years to coordinate its outside consultants. Based on the foregoing, we find that the Company failed to provide sufficient justification to forego the competitive bidding process for the financial benchmarking study. Therefore, we remove $60,000 from the Company’s cost of service (Exh. DPU 17-23, Att. 10 (Supp. 4)).

The Company provided invoices for Apex Analytics during the proceeding but did not include it on its original consultant list (Exhs. NG-RRP-2, Sch. 41, at 4; DPU 17-5; DPU 17-23, Att. 12 (Supp.)). A review of the invoices shows that the work is labelled strategic advisory services with no further detail of the specific services provided (Exhs. DPU 17-23, Att. 12

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104 General Laws c. 164, § 94, outlines statutory deadlines to file rate schedules of five years and ten years for electric and gas companies, respectively. Nonetheless, there is significant leeway within these statutory periods.

(Supp.); DPU 17-23, Att. 12 (Supp. 3)).[105] The Department has previously recognized that issues may arise during a proceeding that require the late addition of rebuttal witnesses. D.P.U. 09-39, at 294. In such circumstances, there may be insufficient time to conduct a competitive bidding process. Here, there is no explanation of what services were provided other than strategic advisory services (Exh. DPU 17-23, Att. 12 (Supp.)). Further, other than providing invoices, the Company was silent as to the services provided (Exhs. NG-RRP-2, Sch. 41, at 4; DPU 17-5; DPU 17-23, Att. 12 (Supp.)). Based on the foregoing, we find that the Company failed to provide sufficient justification to forego the competitive bidding process for Apex Analytics. Therefore, we remove $24,265 from the Company's cost of service (Exh. DPU 17-23, Att. 10 (Supp. 3)).

The Company provided documentation demonstrating that it conducted a competitive bidding process for the remaining service providers (Exh. DPU 17-1 & Atts.). Based on our review of the RFPs and responses, we conclude that National Grid's choices regarding the consultants, including attorneys, obtained through the competitive bidding process were reasonable and cost effective (Exh. DPU 17-1 & Atts.). We also find that the Company appropriately considered price and non-price factors before selecting the providers that it determined would provide the best combination of price and quality of service (Exhs. DPU 17-1 & Atts.; DPU 17-2 & Atts.; DPU 17-3). For each category, the Company selected a provider that possessed expertise and experience, knowledge of Department ratemaking precedent and

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105 Some invoices are labelled ESMP, and the Company provided a delineation of costs that are attributable to services provided in the ESMP proceeding, D.P.U. 24-11, and in this proceeding (Exhs. DPU 17-23, Att. 12, at 3, 6-7 (Supp.); DPU 17-23, Att. 12 (Supp. 3)).

practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks for which it was requested to bid (Exhs. DPU 17-1 & Atts.; DPU 17-2 & Atts.; DPU 17-3). Based on the foregoing, the Department concludes that National Grid conducted a fair, open, and transparent competitive bidding process (Exhs. DPU 17-1 & Atts.; DPU 17-2 & Atts.; DPU 17-3).

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 National Grid and finds that, except for the costs denied above due to lack of a competitive bidding process, the invoices are properly itemized (see, e.g., Exhs. DPU 17-23 & Atts.; DPU 17-23 & Atts. (Supp.); DPU 17-23 & Atts. (Supp. 2); DPU 17-23 & Atts. (Supp. 3)). Further, where the Company provided projected costs to complete the compliance filing following issuance of the Department's Order, National Grid obtained a fixed fee for such projected costs and provided sufficient evidence demonstrating the reasonableness of the fixed fee (Exh. DPU 17-1, Att. 1b at 35 & Att. 7, at 2). The Department finds that the total costs associated with each service provider were reasonable, appropriate, proportionate to the overall scope of work provided, and prudently incurred (see, e.g., Exhs. DPU 17-23 & Atts.; DPU 17-23 & Atts. (Supp.); DPU 17-23 & Atts. (Supp. 2); DPU 17-23 & Atts. (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 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). In addition to considering the average interval between rate cases, the Department has considered the term of a PBR plan in establishing an appropriate rate case expense normalization period. D.P.U. 23-80/D.P.U. 23-81, at 241-242; 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 plan that prevents a company from filing a new rate case for a predetermined period provided 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.

In this case, both the average interval between rate cases and the proposed PBR term recommend a five-year rate case expense normalization period. The average interval between the Company's last four rate cases is five years (see Exh. DPU 17-24).[106] Based on its proposed CPI Plan term, the Company proposes a five-year normalization period (Exh. DPU 17-24). The Department has approved a CPI Plan for the Company that includes a five-year PBR-O plan and stay-out provision. Accordingly, the Department finds that a five-year normalization period is appropriate.

4. Conclusion

The Company has proposed a final rate case expense of $3,486,919 (Exh. DPU 17-23, Att. 10 (Supp. 3)). As outlined above, the Department denied $84,265 in rate case expense. Therefore, we allow final rate case expense of $3,402,654. 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 $680,531 ($3,402,654 divided by five years).

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106 Based on the Company's filing dates for its last four rate cases, between D.P.U. 23-150 and D.P.U. 18-150, the interval is five years; between D.P.U. 18-150 and D.P.U. 15-155, the interval is three years; and between D.P.U. 15-155 and D.P.U. 09-39, the interval is 6.5 years. The sum of these intervals, divided by three and rounded to the nearest whole number results in a normalization period of five years: 14.5/3 = 4.83 (rounded to five).

K. Pension and Post-Retirement Benefits Other Than Pension

1. Background

In December 1985, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards No. 87 ("FAS 87"), which became effective January 1, 1987, and established new accounting standards that significantly changed the manner in which companies account for their obligations relating to employee pensions.[107] In December 1990, the FASB issued Statement of Financial Accounting Standard No. 106 ("FAS 106"), which became effective January 1, 1993, and established similar accounting standards related to PBOP.[108] Through the issuance of FAS 87 and FAS 106, FASB established a systematic method for all companies to recognize employees' future retirement benefit costs.[109] Although FASB dictates the accounting treatment for pension and PBOP expenses, the federal Employee Retirement Income Security Act of 1974 ("ERISA") sets forth requirements for contributions to pension and PBOP plans.

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

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

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

Prior to the new accounting rules in FAS 87 and FAS 106, the Department's accounting treatment for retirement benefits varied by company. See, e.g., D.P.U. 85-270, at 187-188 (pension expense based on most recent actuarial report); D.P.U. 155, at 20-22 (pension expense based on contribution to a company-sponsored trust). The Department allowed most companies to account for their PBOP obligations on a "pay as you go" basis. This approach allowed the companies to charge PBOP costs to expense only when benefits were, in fact, paid out to or for the benefit of retirees. D.P.U. 92-78, at 83; Bay State Gas Company, D.P.U. 89-81, at 29 (1989).

Over the years, changes in accounting rules required the Department to reexamine how best to include a representative level of pension and PBOP expenses in base distribution rates. D.P.U. 96-50 (Phase I) at 81. For pension expenses, typically the Department used an amount equal to the cash contribution to the pension plan as the representative level of pension expense to include in base distribution rates because the Department did not view pension expense recorded for accounting purposes as a true measure of the annual cost of providing employee retirement benefits. See, e.g., D.P.U. 89-114/90-331/91-80 (Phase One) at 65-66; Western Massachusetts Electric Company, D.P.U. 88-250, at 67-72 (1989): D.P.U. 87-260, at 44-47. Regarding PBOP expense, the Department balanced the competing interests of (1) FAS 106 and (2) the need to allocate PBOP expenses appropriately and in a cost-effective manner between current and former ratepayers, as well as between ratepayers and shareholders. See, e.g., D.P.U. 96-50 (Phase I) at 81-86; D.P.U. 92-250, at 52-54.

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

Subsequently, in D.T.E. 03-47, the Department addressed the NSTAR companies' request for a reconciling mechanism. The Department found that between 1999 and 2003, the effects of a declining stock market and steeply falling interest rates had taken their toll on the valuation of the NSTAR companies' pension and PBOP plans, and that without relief the NSTAR companies would be subject to a FAS-required equity write-down entailing significant and impairing financial consequences, with adverse effects on customers. D.T.E. 03-47-A at 19-26, 28. The Department also found a high degree of volatility in the NSTAR companies' pension and PBOP expenses between 1996 and 2003. D.T.E. 03-47-A at 26. The Department determined that approving a reconciling mechanism would be equitable because customers would pay no more than the actual costs incident to (and demanded by FASB to support) pensions and PBOP. D.T.E. 03-47-A at 27. Thus, the Department approved the NSTAR companies' requested reconciling mechanism, with certain modifications. D.T.E. 03-47-A at 29-46.

2. Company PAM

In 2009, National Grid requested that the Department approve an annual adjustment mechanism to recover costs associated with the Company's pension and PBOP obligations that were not currently being collected in base distribution rates. D.P.U. 09-39, at 216. Specifically, National Grid proposed to remove pension and PBOP expenses from base distribution rates and to recover the costs through a fully reconciling mechanism, i.e., a pension adjustment mechanism ("PAM"). D.P.U. 09-39, at 216. Under the proposal, the Company would recover an annual base amount of pension and PBOP expenses, one third of the cumulative over/under collection balance from prior periods, and the carrying charges or credits calculated on its average net prepaid pension asset and deferred PBOP liability net of deferred taxes on the Company's pre-tax weighted cost of capital on a calendar year basis. D.P.U. 09-39, at 216.[110] The Department noted that it had previously approved pension and PBOP adjustment mechanisms similar to the Company's following an examination of the following factors: (1) the magnitude and volatility of pension and PBOP costs, (2) the role of accounting requirements, and (3) the effectiveness of the reconciling mechanism in avoiding the negative effects of the pension and PBOP volatility. D.P.U. 09-39, at 220, citing D.T.E. 05-27, at 123; Fitchburg Gas and Electric Light Company, D.T.E. 04-48 at 19 (2004); D.T.E. 03-40, at 309. The Department found that,

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110 At the time of the petition, the Company had not been collecting carrying charges on pension and PBOP assets. D.P.U. 09-39, at 216.

contrary to National Grid's claims, there had been minimal pension and PBOP expense volatility in recent years, and that the Company's own actuaries projected relatively stable pension and PBOP expenses through the next several years. D.P.U. 09-39, at 221. Nevertheless, the Department granted the Company's request to establish a reconciling mechanism to recover pension and PBOP costs. D.P.U. 09-39, at 221-226.

In approving National Grid's request, the Department found that a fully reconciling mechanism guaranteed recovery of the pension and PBOP deferral within three to five years, satisfied relevant accounting standards, and dispelled the risk that a mismatch between a company's pension and PBOP assets and liabilities would cause serious financial disruption. D.P.U. 09-39, at 222. Further, the Department found that, although the Company was not immediately facing the potential of a significant write-off against shareholder equity, the potential existed for this situation to occur in the future. D.P.U. 09-39, at 222, citing D.T.E. 05-27, at 121; D.T.E. 04-48, at 17; D.T.E. 03-47-A at 25-27; D.T.E. 03-40, at 308-314. The Department also found that, while the Company possessed some amount of control over the cost of the pension and PBOP expenses, it did not have control over interest rates and returns of the broad market. D.P.U. 09-39, at 223. The Department concluded that, given the unique attributes of pension and PBOP costs (i.e., unique accounting requirements along with the potential for significant volatility and lack of Company control), a reconciling mechanism outside of base distribution rates was an appropriate method for the recovery of this specific category of costs. D.P.U. 09-39, at 223. Thus, the Department approved the Company's proposed pension and PBOP reconciling tariff. D.P.U. 09-39, at 223.[111]

3. Company Proposal

During the test year, National Grid reported $12,326,361 in pension expense and negative $6,013,999 in PBOP expense (Exhs. NG-RRP-2, Sch. 3, at 1; NG-RRP-2, Sch. 37, at 1 (Rev. 3); NG-RRP-2, Sch. 38, at 1 (Rev. 3)). National Grid proposes to continue recovering its pension and PBOP expenses outside of base distribution rates through its PAM and states that pension and PBOP expenses remain subject to significant volatility because of forces outside of the Company's control (Exh. DPU 8-3). Consequently, the Company removed the reported test-year expenses from its proposed cost of service through normalizing adjustments in its cost-of-service schedules (Exhs. NG-RRP-2, Sch. 37, at 1 (Rev. 3); NG-RRP-2, Sch. 38, at 1 (Rev. 3); DPU 8-3).

During this proceeding, the Department issued its decision in D.P.U. 23-80/D.P.U. 23-81, at 250-271, regarding Unitil's pension and PBOP expense. As noted in Section II above, the Department then allowed limited additional process for the parties to address the implications of the Unitil decision on the instant proceeding. In response, National Grid submitted additional testimony and documentation relating to the Company's pension and PBOP costs (Exhs. NG-P/PBOP-1; NG-P/PBOP-2; NG-P/PBOP-3; NG-P/PBOP-4). While National Grid advocated to continue the PAM, the Company proposed an alternative ratemaking framework if

111 Subsequently, the Department approved the Company's proposal to change the annual reconciling period for pension and PBOP expense from a calendar year to the twelve months ending September 30. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-48, Stamp Approval (May 15, 2015).

the Department decided to direct recovery of pension and PBOP costs through base distribution rates (Exh. NG-P/PBOP-1, at 33-38). Under the alternative ratemaking proposal, National Grid proposed to include in its base distribution rates $10,743,286 in pension expense and negative $2,325,262 in PBOP expense, which represents the five-year averages of its FAS 87-determined pension expense and FAS 106-determined PBOP expense ("FAS-determined pension and PBOP expenses"), respectively, for the period September 30, 2019 through September 30, 2023 (Exhs. NG-P/PBOP-1, at 34; NG-P/PBOP-2, at 1). The Company also proposed to include the prepaid pension and PBOP balance as of the test year end in rate base (Exhs. NG-P/PBOP-1, at 34). In addition, National Grid proposed that the Department authorize the Company to record the differences between the expense recovery and the FAS-determined pension and PBOP expenses each year as a regulatory asset for recovery in the Company's next base distribution rate case (Exhs. NG-P/PBOP-1, at 34-38; NG-P/PBOP-2, at 1).

4. Positions of the Parties

a. Attorney General

The Attorney General disagrees with the Company's claim that recovering pension and PBOP expenses through base distribution rates will have negative financial accounting and customer impacts (Attorney General Brief at 5 (Supp.), citing Exh. NG-P/PBO-1, at Executive Summary, 8-37). In support of her position, the Attorney General points out that National Grid's total pension and PBOP expenses have been less than one percent of the Company's annual revenues (Attorney General Brief at 5 (Supp.), citing Exhs. AG 29-10, Att. 9, at 38, line 33, Col. (c); AG 29-10, Att. 10; NG-RRP-2, Sch. 1, at 2, line 4, column (a)). She also claims that National Grid acknowledges that any write-down in Company's assets and shareholder equity, or over-recovery from customers, is temporary, as it will be made up through adjustments to the annual pension and PBOP expenses designed to make the Company whole over time (Attorney General Brief at 5-6 (Supp.), citing Exh. NG-P/PBOP-4, at 14).

The Attorney General also rejects National Grid's claim that it essentially has no control over the calculation of pension and PBOP expenses (Attorney General Brief at 6 (Supp.), citing Exh. NG-P/PBOP-4, at 21). She asserts that while National Grid's actuaries may recommend certain inputs into the calculation of these expenses, it is the Company itself that makes the final decisions to determine the annual pension and PBOP expenses (Attorney General Brief at 6 (Supp.), citing Exh. AG 1-2, Att. 5, at 3; D.P.U. 23-80/23-81, at 261). Further, the Attorney General asserts that accounting guidelines afford the Company sufficient leeway to vary its annual expense amount significantly (Attorney General Brief at 6-7 (Supp.)). By way of example, the Attorney General notes that a half percent change in the discount rate that the Company uses to determine the present value of its benefit obligations would create a $9 million change in its $22 million annual pension expense (Attorney General Brief at 6-7 (Supp.), citing Exhs. NG-RRP-P/PBOP-3, at 4; NG-RRP-P/PBOP-4, at 11-15). The Attorney General contends that consistent with industry averages for pension and PBOP expense inputs, National Grid maintains great latitude to determine its pension and PBOP expenses (Attorney General Brief at 7 (Supp.), citing Exh. NG-RRP-P/PBOP-4, at 12-13, 15).

The Attorney General further claims that National Grid grossly underestimates the expected return on plan assets ("EROA") in the pension and PBOP trust fund (Attorney General Brief at 7 (Supp.)). She argues that the Company's assumed return of 7.59 percent is well below any reasonable estimate of the long-run market return on common equities (Attorney General

Brief at 7 (Supp.), citing Exh. AG 3-11, Att. at 2). She points out that the Company's cost of capital witness testified that the expected market return on common equity is at 12.5 percent (Attorney General Brief at 7 (Supp.) citing Exh. NG-AEB-1, at 48). She asserts that using this 12.5 percent return on common equity would result in reductions to the Company's annual pension expenses by approximately $12.7 million and reductions to the annual PBOP expenses by more than $2.5 million (Attorney General Brief at 7-8 (Supp.), citing Exhs. AG 1-2, Att. 5, at 27).

The Attorney General also maintains that National Grid unreasonably overstated its history of annual increases in employee wages in that the Company used 4.25 percent for union employees and 4.3 percent for non-union employees (Attorney General Brief at 8 (Supp.), citing Exh. AG 1-2, Att. 5, at 28). She contends that the Company's average wage and salary increases in the past ten years have been only 2.78 percent for union employees and 3.28 percent for non-union employees (Attorney General Brief at 8 (Supp.), citing Exh. AG 29-9). Even allowing for the Company's claimed 0.5 percent adder for recognized promotions and progressions, the more reasonable estimated annual increases in employee wages and salaries should be 3.28 percent for union employees and 3.78 percent for non-union employees (Attorney General Brief at 8 (Supp.), citing Exh. NG-HRP-1, at 12). The Attorney General argues that the Company's overestimates of annual pay increases demonstrate that the Company can manipulate its pension and PBOP input assumptions, resulting in customers overpaying for pension and PBOP costs (Attorney General Brief at 8 (Supp.)).

In conclusion, the Attorney General recommends that the Department maintain a reconciling mechanism either through a separate reconciling charge or through a fixed amount in base distribution rates, with deferral of the difference between base distribution rate recovery and the FAS-determined pension and PBOP expenses (Attorney General Brief at 9 (Supp.)). In particular, the Attorney General recommends the following parameters of cost recovery to ensure fair rate treatment for customers if the Department eliminates the PAM: (1) the expense should be based on the five-year average of FAS-determined pension and PBOP expenses to mitigate short-term volatility; (2) to the extent that there is a Department-approved rate plan, the expense can be included in any annual inflation increase to recognize the inflation component of pension and PBOP costs; (3) the rate plan should include a charge or credit in the Company's next base distribution rate case for the deferral that equals the difference between the base distribution rate recovery inclusive of cumulative annual increases and the FAS-determined pension and PBOP expenses; and (4) there should be no carrying charges on the prepaid asset or liability (Attorney General Brief at 9-10 (Supp.)).

b. Company

The Company contends that its supplemental testimony and discovery responses on this issue demonstrate that its PAM is the optimal ratemaking framework that aligns all components of pension and PBOP expenses in a way that best benefits and protects customers over the long run and allows the Company to recover its reasonably incurred costs (Company Brief at 7, 8, 21-23 (Supp.), citing Exh. NG-P/PBOP-4, at 7-9).[112] National Grid claims that customers are the ultimate beneficiaries of a PAM because they pay no more and no less than FAS-determined

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[112] In its initial brief, National Grid argues that the Department has not developed a "full and balanced" evidentiary record on this issue (Company Brief at 329). We consider this argument moot because of the supplemental testimony and discovery responses filed after the Department granted the Company's request to reopen the record.

actual pension and PBOP expenses, they compensate the Company's prefunding to receive the investment benefit of the reduction to the FAS-determined actual pension and PBOP expenses, and they benefit from the prefunding because a well-funded plan reduces the federally mandated contribution requirement (Company Brief at 21-23 (Supp.), citing Exh. NG-P/PBOP-4, at 7-9). National Grid argues that without a PAM based on actual costs, customers would be deprived of the economic benefits of plan contributions and related investment earnings (Company Brief at 23 (Supp.), citing Exh. NG-P/PBOP-4, at 9).

The Company claims that its pension and PBOP costs are significant and highly variable, with significant fluctuations that make it difficult to establish a representative amount to include in base distribution rates (Company Brief at 343, citing Exh. DPU 31-9; Company Brief at 46 (Supp.), citing Exh. DPU 52-3). National Grid maintains that with a highly variable cost, it is difficult to set a base distribution rate that would have a reasonable certainty to provide the Company with fair and adequate recovery without over-charging customers, particularly where these costs have the potential to turn to income, which then benefits customers when passed through to them (Company Brief at 343, citing Exh. DPU 31-9; Company Brief at 46 (Supp.), citing Exh. DPU 52-3).

The Company argues that pension and PBOP expenses are unique constructs with a level of expense varying substantially from year-to-year primarily due to factors outside the Company's control, such as the financial markets (Company Brief at 329-330, 344, citing Tr. 7, at 1037-1038; Company Brief at 6, 23, 34 (Supp.), citing Exh. NG-P/PBOP-1, at 1, 4, 19)). For example, National Grid asserts that its pension expense went from \$17.8 million in fiscal year 2022 to negative \$4 million in fiscal year 2023, a \$21.8 million reduction in just one year

(Company Brief at 331-332, citing Exhs. DPU 48-6; DPU 8-7). Similarly, the Company asserts that its PBOP expense went from $2.8 million in fiscal year 2019 to a negative $45,000 in fiscal year 2020 (Company Brief at 332, citing Exhs. DPU 48-6; DPU 8-7). National Grid contends that in its most recent PAM filing, the Company's pension expense is negative $12 million, and its PBOP expense is negative $10 million (Company Brief at 332-333, citing Tr. 7, at 1033-34, 1040 (including NGSC costs); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-03, Exh. NG-2, at 2 (pending)). The Company maintains that this variability justifies a recovery mechanism that assures that no more and no less than the actual pension and PBOP expenses are collected from customers (Company Brief at 330; Company Brief at 6-7 (Supp.)).

Further, the Company argues that the Department's recent decision in D.P.U. 23-80/D.P.U. 23-81 understates the significance of maintaining this recovery equilibrium from both accounting and ratemaking perspectives (Company Brief at 330; Company Brief at 7-8 (Supp.)). The Company contends that the mechanics that the Department put in place for Unitil to incorporate pension and PBOP costs into base distribution rates are incorrect (Company Brief at 330). In particular, National Grid faults the Department's exclusion of prepaid assets from rate base and the inclusion of an offsetting impact of accumulated deferred income tax (along with the Department's apparent elimination of any deferral mechanism) as conceptually and methodologically inappropriate (Company Brief at 330; Company Brief at 8 (Supp.)). National Grid also claims that eliminating the deferral mechanism would be highly detrimental to the Company, particularly in the context of a five-year rate plan (Company Brief at 330; Company Brief at 41-42 (Supp.), citing Exh. NG-P/PBOP-1, at 29).

The Company asserts that a negative pension and PBOP expense benefits customers and reduces their overall cost, so long as the negative expense is accounted for in rates (Company Brief at 341, citing Exh. DPU 8-7). National Grid argues that base distribution rates would not account for negative expense because it is not representative of the Company's actual cost over time, nor are pension and PBOP expenses in any particular year representative of expense in the next year, whether positive or negative (Company Brief at 341, citing Exh. DPU 8-7). Consequently, the Company argues that building a large negative expense into base distribution rates will have two detrimental impacts over the course of the PBR-O term (Company Brief at 330; Company Brief at 41 (Supp.)). First, the Company maintains that the incorporation of a negative expense in base distribution rates will cause a material reduction of operating cash flow through base distribution rates by reducing base distribution revenues to incorporate a non-cash, negative expense (Company Brief at 330-331; Company Brief at 41-42 (Supp.)). Second, incorporating negative amounts in base distribution rates will reduce the annual PBR revenue adjustment by artificially reducing the level of distribution revenue approved by the Department in this case, which would have a cumulative impact over the term of the PBR-O plan (Company Brief at 330-331; Company Brief at 41-42 (Supp.)). The Company contends that neither outcome is appropriate or consistent with the assumptions that it has relied on for its proposed PBR-O plan (Company Brief at 331; Company Brief at 41-42 (Supp.)).

On brief, National Grid analyzes its pension and PBOP expenses to demonstrate the volatility in the actual pension expense and forecasted pension and PBOP expenses (Company

Brief at 331-332; Company Brief at 32 (Supp.)).[113] National Grid's analysis provides the actual, total pension and PBOP expenses recorded on the Company's books for the fiscal years ended 2014 through 2024 and the forecasted actuarial pension and PBOP expenses for the fiscal years ended 2025 through 2029 (Company Brief at 331, citing Exhs. DPU 8-7; DPU 48-6). The Company calculates an estimated calendar year 2024 pension and PBOP expenses booked to O&M expense, including the amounts charged from NGSC, of negative $22 million (Company Brief at 333). The Company maintains that when its actual costs swing to a positive balance as projected for 2028 and 2029, distribution rates will not account for that swing, to the detriment of customers (Company Brief at 333-334; Company Brief at 41 (Supp.)).

In addition, the Company asserts that since fiscal year 2018, pension and PBOP expenses have been separated into service costs and non-service costs for accounting purposes (Company Brief at 333). According to National Grid, service costs are capitalized based on the Company's labor charges and non-service costs, as represented by interest costs related to its pension and PBOP obligation, EROA, prior service cost amortization, and gains and losses amortization (Company Brief at 333). The Company argues that while service costs are normally positive, non-service costs fluctuate greatly (Company Brief at 333, citing Exh. DPU 24-3). National Grid maintains that changes in pension and PBOP assumptions including discount rates and expected returns have the potential to cause these items to change significantly (Company Brief at 333). The Company contends that although the interest cost equals the liability times the

113 For purposes of this analysis, the Company's pension and PBOP costs have not been disaggregated, and NGSC pension and PBOP costs have not been included (Company Brief at 333).

discount rate, and reflects the cost over the passage of time for a year and fluctuates with discount rate changes, these fluctuations can be counter-intuitive, e.g., a discount rate increase results in a lower liability but the liability is multiplied by a bigger number, so a 25-basis point change may go in a completely different direction than a 100-basis point discount rate change (Company Brief at 333 n.71). National Grid argues that because EROA equals asset base times the EROA assumption, the liability will fluctuate with actual asset values and the EROA assumption (Company Brief at 333 n.71). Further, the Company contends that its EROA assumption leads to an increase to EROA based on the capital market outlook, with high expectations to recover losses incurred in the previous year (Company Brief at 333 n.71). The Company asserts that amortization for gains/losses reflects changes in discount rate, actual asset experience, demographic experience, and other assumptions (Company Brief at 333 n.71).

On brief, National Grid criticizes the Department's decision to discontinue Unitil's PAM in D.P.U. 23-80/D.P.U. 23-81 (Company Brief at 334-335, citing D.P.U. 23-80/D.P.U. 23-81, at 250-271, 260; Company Brief at 7 (Supp.)).[114] National Grid claims that in reaching this conclusion, the Department relied on three contestable propositions: (1) that the adoption of FAS 158 and the Pension Protection Act of 2006, P.L. No. 109-280 (2006) obviated any financial accounting reasons not to recover pension and PBOP expenses from base distribution rates; (2) that the Company has a degree of control over key actuarial assumptions like the discount rate and the return on plan assets that inform calculations of pension and PBOP

[114] Unitil has filed a post-Order motion challenging the Department's decision in D.P.U. 23-80/D.P.U. 23-81 to discontinue Unitil's PAM. The Department will address Unitil's arguments in that docket.

expenses; and (3) that changing the method of recovering pension and PBOP expenses would not adversely affect the Company's credit (Company Brief at 335, citing D.P.U. 23-80/D.P.U. 23-81, at 260-262; Company Brief at 8-9, 24-25 (Supp.)). The Company elaborates on these arguments at length in its initial and supplemental briefs (see, e.g., Company Brief at 335; Company Brief at 8-9 (Supp.)).

National Grid disputes the Department's findings in D.P.U. 23-80/D.P.U. 23-81 that FAS 158 and the Pension Protection Act of 2006 addressed the concern that financial accounting requirements could have a detrimental impact on shareholders' equity and thereby largely removed any financial accounting reasons for these costs to be recovered outside of base distribution rates (Company Brief at 339). Rather, National Grid argues that FAS 158 and the Pension Protection Act of 2006 were independent policy changes that did not have the effects the Department claimed. The Company asserts that neither FAS 158 nor the Pension Protection Act of 2006 eliminated the risk that significant market events or changes in governing law and regulation could affect the prepaid balance or other deferred asset and liability balances (Company Brief at 337; Company Brief at 12-15 (Supp.)). Further, National Grid argues that FAS 158 does not avoid a profit and loss impact due to expense recognition (Company Brief at 337; Company Brief at 12 (Supp.)). The Company claims that FAS 158 simply required a balance sheet "gross-up" and did not incorporate any adjustment to pension and PBOP expenses (Company Brief at 337; Company Brief at 15 (Supp.)). The Company maintains that settlement accounting for employees still exists unchanged today, which means that an acceleration of expense recognition could reduce shareholders' equity under certain circumstances (Company Brief at 337). Moreover, the Company contends that due to FAS 158, additional minimum liability no longer exists, and pension assets or liabilities must be recorded on the balance sheet (Company Brief at 337; Company Brief at 15 (Supp.)). More fundamentally, the Company asserts that FAS 158 did not change the underlying economics requiring companies to rely on their debt and equity capitalizations to finance contributions in advance of the expense incurrence (Company Brief at 337).

National Grid further contends that the accounting rules to recognize a regulatory asset have not changed since 2003 (Company Brief at 338). The Company claims that whether the Company has a pre-FAS 158 additional minimum liability, or the funded status from FAS 158, it is necessary to look to FASB Accounting Standards Codification ("ASC") 980 (previously FAS 71) to determine if that offset can be a regulatory asset or is a charge to equity (Company Brief at 338; Company Brief at 26 (Supp.)). National Grid argues that the fact that the PAM exists is the primary evidence that allows the Company to record the regulatory asset and avoid a charge to equity (Company Brief at 338; Company Brief at 26 (Supp.), citing Exh. DPU 52-5). According to the Company, taking away the PAM causes more of an ASC 980 recognition concern than presented by FAS 158 (Company Brief at 338; Company Brief at 27 (Supp.)).

The Company also argues that the Department erred in its conclusions in D.P.U. 23-80/D.P.U. 23-81 regarding the Company's control over key accounting inputs like the discount rate and EROA (Company Brief at 339; Company Brief at 27 (Supp.)). The Company claims that the record shows that the discount rate must be determined using rates of return on high-quality fixed income investments, such as highly rated corporate bonds (Company Brief at 339-340; Company Brief at 6, 18 (Supp.)). The Company maintains that because it has no control over the comparable corporate bond rates that determine the discount rate, the

Department's premise that the discount rate is within the company's control is inaccurate (Company Brief at 339-40, citing Tr. 7, at 1039; Company Brief at 34-35 (Supp.)). Continuing, National Grid argues that its work with actuaries to review and designate plan assumptions does not establish that the Company has control over the primary drivers of pension and PBOP expenses (Company Brief at 16-21 (Supp.), citing Exh. NG-P/PBOP-4, at 11-15). The Company also argues that ASC 715 effectively requires plan sponsors to use a discount rate within a tight bandwidth dependent on the rates of high-quality fixed income investments (Company Brief at 339-340; Company Brief at 17-18, 21 (Supp.), citing Exh. NG-P/PBOP-4, at 12, 15).

National Grid also asserts that it has limited control over setting assumptions regarding EROA (Company Brief at 19 (Supp.)). The Company claims that, according to an annual global survey of accounting assumptions for defined benefit plans dated December 31, 2023, there is a very tight bandwidth in setting assumptions of EROA (Company Brief at 21 (Supp.), citing Exh. NG-P/PBOP-4, at 15). The Company argues the EROA is its best estimate of the long-term investment returns that the plan will attain based on the current asset investment allocation, and to the extent that actual investment returns are different than the expected return recognized for expense purposes, that difference is amortized over future periods (Company Brief at 19 (Supp.), citing Exh. NG-P/PBOP-4, at 13-14). National Grid asserts that there is no nexus between the EROA for the Company's pension funds and the calculation of the allowed ROE used for rate-setting purposes (Company Brief at 19-20 (Supp.), citing Exh. AG 29-15; D.P.U. 10-55, at 283).

National Grid also takes issue with the Unitil Order aside from accounting assumptions (Company Brief at 4-6 (Supp.), citing D.P.U. 23-80/D.P.U. 23-81). For example, the Company claims that there is no reasonable method to derive a representative amount to include in base distribution rates that would not harm either customers or the Company (Company Brief at 1 (Supp.)). The Company contends that its FAS-determined pension and PBOP expenses are exponentially greater in magnitude and volatility than those identified for Unitil in D.P.U. 23-80/D.P.U. 23-81, and that the Department's use of a three-year average of pension and PBOP expenses as a measure of representativeness in D.P.U. 23-80/D.P.U. 23-81 is inapplicable in this case (Company Brief at 340).

The Company argues that its circumstances differ from those presented in the Unitil matter. Specifically, the Company claims that its pension and PBOP expenses in 2022 were $13,041977 and, in 2023 and 2024, it had shifted significantly to a material negative expense, meaning a three-year average is completely unrepresentative (Company Brief at 341). More broadly, the Company argues that pension and PBOP expenses are volatile, with routine $10 million swings in pension expense from year to year over the past ten years (Company Brief at 341, citing Tr. 7, at 1036).

National Grid contends that applying the pension and PBOP recovery method from D.P.U. 23-80/D.P.U. 23-81 would harm its customers (Company Brief at 5, 7 (Supp.)). National Grid contends that its ratepayers will pay $35 million and $71.2 million more using the three-year average and five-year average FAS-determined pension and PBOP expenses, respectively, than they would with the PAM (Company Brief at 5 (Supp.)). Moreover, National Grid asserts that shifting a single year in calculating the average expense causes the Company to under-collect $40.3 million and $46.4 million for three-year and five-year averages, respectively (Company Brief at 5 (Supp.), citing Exh. NG-P/PBOP-4, at 5-6, 9).

The Company also questions the Department's observation in the Unitil decision that "it takes two years to reconcile a year of the cost" as a reason to terminate the PAM (Company Brief at 342, citing Tr. 7, at 1001). National Grid maintains that the reconciliation is neither complicated nor slow and the forecast would be trued up to actuals in the following year (Company Brief at 342, citing Tr. 7, at 1001). The Company asserts that it would be open to any changes in schedule or approach that would ease the burden of PAM reviews for the Department (Company Brief at 342; Company Brief at 42 (Supp.), citing Exh. NG-P/PBOP-1, at 29-30).

The Company also disagrees with the Department's treatment of regulatory assets and deferrals as they relate to pension and PBOP expenses (Company Brief at 5, citing D.P.U. 23-80/D.P.U. 23-81). Broadly, the Company contends that the Unitil Order does not effectively match actual costs, as does the current, annually reconciling PAM, and is not a practice seen in other jurisdictions (Company Brief at 51 (Supp.), citing Exh. NG-P/PBOP-4, at 22). National Grid claims that rate recovery for pension and PBOP costs across the United States includes: (1) rate recovery mechanisms that reconcile the expense amounts collected from customers to the actual amount incurred; (2) rate recovery of cash contributions with reconciliation to amounts recognized under ASC 715; (3) inclusion of pension and PBOP expenses in base distribution rates based on test-year expenses; and (4) inclusion of pension and PBOP expenses in base distribution rates based on the projected expenses for the rate year (Company Brief at 51 (Supp.), citing Exh. NG-P/PBOP-4, at 22). The Company further claims that many of the jurisdictions include a return on prepaid assets, as the Department has approved for over 20 years through the PAM (Company Brief at 52 (Supp.), citing Exh. NG-P/PBOP-4, at 22-23).

More specifically, National Grid contends that it is required by law to contribute funds to its pension plan and that the cumulative funding in excess of cumulative expense results in a prepaid pension asset (Company Brief at 344). The Company maintains that prepaid pension and prepaid PBOP are calculated each year by adding contributions and ASC 715 pension and PBOP expenses to the prior year balance (Company Brief at 342, citing Exh. DPU 31-8).[115] The Company also argues that prepaid pension is a regulatory asset that represents the cumulative difference between required plan cash contributions and pension expense recognized in accordance with ASC 715 (Company Brief at 342; Company Brief at 42 (Supp.), citing Exh. NG-P/PBOP-1, at 30). The Company claims that this regulatory asset is supported by the Company's capitalization and is financed by its overall capital structure (Company Brief at 342; Company Brief at 44 (Supp.), citing Exh. NG-P/PBOP-1, at 31). The Company argues that the Department cannot ignore the prepaid asset and exclude the commitment of utility resources to plan contributions (Company Brief at 343).[116] National Grid argues that the omission of any ratemaking treatment of prepaid assets in D.P.U. 23-80/D.P.U. 23-81 creates an improper

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115 National Grid maintains that primarily because of the adoption of FAS 158 during the fiscal year ended March 31, 2007, prepaid pension and prepaid PBOP balances do not explicitly exist in the Company's general ledger or chart of accounts (Company Brief at 342 citing Exh. DPU 31-8). A reconciliation of prepaid pension and prepaid PBOP balances between the general ledger, chart of accounts, and the PAM filings is provided in Exhibit DPU 31-8 (Company Brief at 342 citing Exh. DPU 31-7 & Att.; DPU 31-8 & Att.).

116 National Grid maintains that the Department's failure to account for prepaid pension and PBOP assets in D.P.U. 23-80/D.P.U. 23-81 is a significant omission that must be addressed if the Department decides to move ahead with the elimination of the Company's PAM (Company Brief at 342; Company Brief at 44 (Supp.), citing Exh. NG-P/PBOP-1, at 32).

imbalance between the Company and its customers (Company Brief at 334-336; Company Brief at 8-9 (Supp.), citing Exh. NG-P/PBOP-1, at 5, 12-13).

Continuing, National Grid argues that although pension expense is a non-cash accrued expense, the collection from customers is revenue that results in operating cash flows to the Company (Company Brief at 343; Company Brief at 44 (Supp.), citing Exh. NG-P/PBOP-1, at 32). Thus, according to National Grid, in a year when pension expense is less than plan contributions, the reduction in cash flows directly affects the Company's financing costs (Company Brief at 343; Company Brief at 44-45 (Supp.), citing Exh. NG-P/PBOP-1, at 32-33). In this regard, the Company claims that it must be compensated for the financing cost that it incurs due to the timing difference between the pension expense collected from customers and the amounts contributed to the plan (Company Brief at 343; Company Brief at 45 (Supp.), citing Exh. NG-P/PBOP-1, at 33). The Company maintains that it expects that future pension expense will exceed the required contributions and that over time this will reduce the prepaid pension regulatory asset (Company Brief at 343; Company Brief at 45 (Supp.), citing Exh. NG-P/PBOP-1, at 33).

National Grid claims that there is a significant regulatory asset associated with FAS-determined pension and PBOP expenses that requires an appropriate recovery path, and that there is no way for the Company to recover its contributions to the plan fund (Company Brief at 1-2 (Supp.)). National Grid asserts that without carrying charges on prepaid pension and PBOP amounts, there is an asymmetrical benefit to customers and a penalty for the Company where a real cost is being incurred for the customers' benefit (Company Brief at 2 (Supp.)). The Company contends that pre-funding is a direct benefit to the customers and that the associated ratemaking treatment is necessary (Company Brief at 6 (Supp.)). National Grid argues that when it makes cash contributions to the plan, customers receive immediate income tax deductions and the associated ADIT for rate base deduction (Company Brief at 6 (Supp.)). Additionally, the Company asserts that the recovery of pension and PBOP expenses needs to correlate to the recovery of a regulatory asset for the independent auditors to sign off on the probability of regulatory asset recovery (Company Brief at 2, 5 (Supp.)). National Grid alleges that, in contemplating eliminating the PAM, the Department has inadequately considered the need of utilities to demonstrate the probable recovery of the deferred, incurred cost through a reasonable ratemaking framework (Company Brief at 5-6 (Supp.)).

The Company argues that, if the Department terminates the PAM, it also must appropriately account for all cost elements by establishing a deferral mechanism for the amounts incurred/accrued over or under the representative amount (Company Brief at 46-47 (Supp.), citing Exh. DPU 52-3). The Company maintains that the Department needs to incorporate three cost elements as described further below to ensure the Company can maintain the regulatory asset and to reduce the risk of a write-down of the asset (Company Brief at 48 (Supp.)). First, the Company contends that the amount included in base distribution rates should be based on the reasonably tracked ASC 715 determined expenses, i.e., the five-year average of the FAS-determined expenses (Company Brief at 48 (Supp.), citing Exhs. NG-P/PBOP-1, at 33-34; NG-P/PBOP-4, at 19-20)). Second, the Company contends that the Department needs to allow the difference between the amount in base distribution rates and actual ASC 715 expense to be deferred to a regulatory asset for amortization in base distribution rates in the next base distribution rate case, i.e., authorize a deferral of under or over the representative amount in base distribution rates with carrying charges applied to that balance at the WACC on a symmetrical basis (Company Brief at 48 (Supp.), citing Exhs. NG-P/PBOP-1, at 33-34; NG-P/PBOP-4, at 19-20). Third, National Grid contends that the Department needs to establish a prepaid asset net of ADIT and establish a return on prepaid asset to recognize the Company has funded the benefits using its own capitalization for the customer's benefit, i.e., provide the same treatment to all other rate base assets by including the balance of prepaid balance in rate base (Company Brief at 48-49 (Supp.), citing Exhs. NG-P/PBOP-1, at 33-34; NG-P/PBOP-4, at 19-20).

National Grid asserts that its WACC represents the appropriate carrying charge on the net prepaid contribution to compensate for the time value of its payments until the prepaid amount decreases to zero in a future year that cannot be identified with certainty (Company Brief at 49-50 (Supp.), citing Exhs. NG-P/PBOP-1, at 34; DPU 52-4). In support of its proposed carrying charge, National Grid asserts that because the prepaid amount was contributed at a time when the IRS rules permitted such a contribution on a tax-deductible basis, and when the Department encouraged EDCs and LDCs to make contributions to their plans equal to the full amount of their tax deductible levels, carrying charges should be included as an appropriate ratemaking mechanism to reflect the money the Company is incurring to prefund its obligation (Company Brief at 50 (Supp.), citing Exh. NG-P/PBOP-1, at 35). The Company further argues that the carrying charges provide benefits to customers in the Company's PBOP with the deferral balance in a negative amount (Company Brief at 50 (Supp.), citing Exh. NG-P/PBOP-1, at 35). Therefore, National Grid asserts that the carrying charges applied symmetrically recognize the time value of money for the Company and its customers (Company Brief at 50-51 (Supp.), citing Exh. NG-P/PBOP-1, at 35-36).

5. Analysis and Findings

a. Continuation of Company PAM

The Department has addressed the propriety of reconciling mechanisms as a ratemaking tool in several prior decisions and has identified factors to consider when evaluating whether to institute or maintain reconciling mechanisms. These factors include whether the costs to be recovered: (1) are volatile and fairly large in magnitude; (2) are neutral to fluctuations in sales volumes; and (3) are beyond the control of the company. D.P.U. 07-50-A at 50 (2008); D.T.E. 05-27, at 183-186; D.T.E. 03-47-A at 25-28, 36-37. The Department considers whether reconciling mechanisms or base distribution rates are the optimal cost recovery method on a case-by-case basis in base distribution rate proceedings, where the distribution company must demonstrate that continued recovery in a separate mechanism is warranted. D.P.U. 07-50-A at 50. The Department has reviewed the evidence, as discussed below, and we are persuaded that the continuation of the Company's PAM no longer is warranted.

As an initial matter, FAS-determined pension and PBOP expenses are non-cash accrued expenses derived in accordance with FAS 87 and FAS 106 that require plan sponsors to record on their financial statements the cost of providing post-retirement benefits as those benefits are earned by employees over the years that they provide service to the Company (Exhs. NG-P/PBOP-1, at 32; NG-P/PBOP-4, at 3-4). These expenses, net periodic benefit costs, include service cost, interest cost, EROA, amortization of prior service cost, and amortization of net gain or loss (Exhs. AG 1-2, Att. 5, at 28; AG 1-49, Att. 1, at 111; AG 1-49, Att. 2, at 104; AG 1-49, Att. 3, at 103; AG 1-49, Att. 4, at 116; AG 29-1, Att. 1, at 9-11; RR-DPU-31, Att. 1, at 41).[117] Due to the long-term nature of obligations to retirees, companies must make assumptions about future economic and demographic conditions (Exh. NG-P/PBOP-4, at 3-5; AG 29-1, Att. 1, at 13). Each component of the FAS-determined expenses changes based on the assumptions (Exhs. AG 1-2, Att. 5, at 28; AG 1-49, Att. 1, at 111; AG 1-49, Att. 2, at 104; AG 1-49, Att. 3, at 103; AG 1-49, Att. 4, at 116; RR-DPU-31, Att. 1, at 41). Plan sponsors are not required to reflect the effect of assumption changes in trust earnings as they occur, and instead, those gains and losses are amortized over future periods, i.e., amortization of prior service cost and amortization of gain or loss to the FAS-determined pension and PBOP expenses in the future (Exhs. NG-P/PBOP-4, at 3; AG 29-1, Att. 1, at 11-12). Therefore, from a financial accounting perspective, the FAS-determined expenses are a function of actual expenses for pension and PBOP plans (Exhs. NG-P/PBOP-4, at 4; AG 29-1, Atts.). When the plan sponsor records the FAS-determined pension and PBOP expenses, it increases its pension and PBOP liability on the balance sheet and increases its pension and PBOP expenses on the income statement (Exhs. NG-P/PBOP-4, at 4; DPU 8-6, Att.). More specifically, under FAS 87 in effect when the Department issued D.T.E. 03-47-A, the plan sponsor was required to record an additional minimum liability on its balance sheet if the accumulated pension obligation exceeded the fair value of the pension asset on the annual plan evaluation date (Exhs. NG-P/PBOP-4, at 9-10; AG 29-1, Att. 1, at 4). In other words, financial accounting standards in 2003 required the creation of a recovery mechanism for pension and PBOP deferrals over a reasonable time

117 See Statement of FAS 87 Employer’s Accounting for Pension for more detailed information about each component of the FAS-determined pension and PBOP expenses (Exh. AG 29-1, Att. 1).

period for companies to treat these deferrals as regulatory assets. D.T.E. 03-47-A at 20-21. In the absence of such a recovery mechanism, companies would have been required to write down their common equity in an amount equal to the sum of the after-tax cost of both the additional minimum liability and the pension and PBOP deferral. D.T.E. 03-47-A at 21.

Whereas the FASB sets accounting standards, ERISA establishes the minimum funding requirement for pension contributions, and the Pension Protection Act of 2006 provides comprehensive guidance on the timing of the pension contributions needed to maintain employer-sponsored retirement plans. 29 U.S.C. § 18; 26 U.S.C. § 401; 26 C.F.R. § 11.412(c); 26 C.F.R. § 412; 26 C.F.R. § 430. The IRS determines the minimum required contribution (Exhs. NG-P/PBOP-4, at 4; DPU 31-14). 26 C.F.R. § 430. When a plan sponsor makes a cash contribution to a pension trust fund, it decreases both its pension liability and cash on the balance sheet (Exh. NG-P/PBOP-4, at 4). Although FAS-determined pension and PBOP expenses and cash contributions represent the same cost, the difference between the accumulated expenses and contributions is recorded as a prepaid asset (prepaid pension/prepaid PBOP) or accrued liability (accrued pension/accrued PBOP) under FAS 87 and FAS 106 (Exh. NG-P/PBOP-4, at 4).

In September 2006, FASB issued FAS 158, which requires recording of pension and PBOP as either a liability or an asset representing the funded status of the respective plans, i.e., if a company's projected benefit obligation exceeds the fair value of plan assets, a liability that equals the unfunded projected benefit obligation is recorded on the balance sheet, and if the fair value of plan assets exceeds the projected benefit obligation, an asset that equals the overfunded projected benefit obligation is recorded on the balance sheet (Exhs. NG-P/PBOP-1, at 9; NG-P/PBOP-4, at 3,5-6, 14; AG 29-2, Att. 1, at 3). The goal of FAS 158 is to communicate the plan-funded status to shareholders (Exhs. NG-P/PBOP-1, at 9; NG-P/PBOP-4, at 5; AG 29-2, Att. 1, at 4). National Grid states that FAS 158 eliminated the need to record the additional minimum liability under FAS 87 (Exh. NG-P/PBOP-4, at 9-10). The prepaid asset (accrued liability) no longer exists on the Company's general ledger due to the adoption of FAS 158 (Exh. DPU 31-8). Nonetheless the Company states that FAS 158 did not eliminate the risk of a reduction to the Company's common equity because the funded status is greater than the additional minimum liability and increases the regulatory asset (Exhs. NG-P/PBOP-1, at 10-11; NG-P/PBOP-4, at 6).

The Department is not persuaded that the funded status recorded in the Company's balance sheet has ratemaking implications. Specifically, the funded status is recorded within "other comprehensive income" and represents unrecognized gains and losses (Exhs. NG-P/PBOP-4, at 5; AG 29-2, Att. 1, at 3).[118] The Department observes that the Company's accumulated other comprehensive income is itemized in the notes to the annual financial statements (Exh. AG 1-2, Att. 3, at 26, Att. 5, at 26, Att. 6, at 24-26, Att. 8, at 23-24, Att. 10, at 22-23).[119] As a result, these unrecognized gains and losses have not burdened customers and should not be recognized as a regulatory asset. D.P.U. 22-22, at 145-147. In

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118 Under generally accepted accounting principles, "other comprehensive income" represents revenue, expenses, gains, and losses that will not be included within the determination of net income until a future accounting period (Exhs. NG-RRP-P/PBOP-4, at 6; AG 29-1, Att. 1, at 11-12).

119 The disclosure of changes to accumulated other comprehensive income is required as further detail in the Statement of Stockholders' Equity. Financial Accounting Standards Board, Taxonomy Implementation Guide V. 5.1 (May 2018), https://www.fasb.org/projects/fasb-taxonomies/resources/taxonomy-implementation-guides

addition, for the Department to allow a regulated company to record a regulatory asset, the expense needs to be an incurred cost. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 10-54, at 318 n.235 (2010); D.T.E. 03-47-A at 3 n.2. National Grid states that a regulated utility does not automatically record a regulatory asset related to pension and PBOP expenses and, therefore, the Company is able to record the difference between the FAS-determined pension and PBOP expenses and the collection through rates as a regulatory asset with the PAM in place (Exhs. NG-P/PBOP-4, at 10; DPU 52-5, at 2). FERC granted regulated utilities the option to record a regulatory asset for the funded status required by FAS 158 in its accounting order in 2007 (Exhs. NG-P/PBOP-4, at 10-11; DPU 52-5, at 2).[120] FERC does not dictate the Department's accounting treatment for ratemaking purposes, however, because the Department's ratemaking takes into considerations many factors other than account balance. D.P.U./D.T.E. 97-95, at 76-77; D.P.U. 95-118, at 107; D.P.U. 94-50, at 305; D.P.U. 92-78, at 79-80; Cape Cod Gas Company, D.P.U. 20103, at 18-19 (1979). A regulatory asset is created when regulators provide reasonable assurance of the 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). In addition, unlike FERC orders, the Department's ratemaking is not on a fully normalized accounting basis (see

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120 In its Staff's Guidance on Formula Rate Updates issued on July 17, 2014, FERC stated that certain costs are required to be excluded in rate determinations absent Commission authorization, which include the Commission Accounting and Reporting Guidance to Recognize the Funded Status of Defined Benefit Postretirement Plans, Docket No. AI07-1-000 (March 29, 2007). https://www.ferc.gov/sites/default/files/2020-04/staff-guidance.pdf.

Section VII.; Section VIII). Further, the funded status balance is amortized over future periods into net periodic benefit cost, i.e., FAS-determined pension and PBOP expenses (Exhs. NG-P/PBOP-4, at 3-5, 14; AG 29-1, Att. 1, at 12; AG 29-2, Att. 1, at 3). Thus, the effect of the funded status in the Company's financial statement, i.e., write-down of equity, is temporary.[121] Allowing a regulatory asset based on the funded status along with the recovery of FAS-determined pension and PBOP expenses would result in double recovery. Therefore, the Department disallows the recording of the regulatory asset resulting from the requirements of FAS 158. With respect to National Grid's argument about the implication of equity write-off, the Department finds that the equity write-off is absent without the recognition of a regulatory asset (Exh. NG-P/PBOP-10-11).[122] For this reason, the Company's statements regarding ASC 980 are effectively moot (Exhs. NG-P/PBOP-1, at 11; NG-P/PBOP-4, at 18; DPU 52-5). In addition, as the prepaid amounts are part of the funded status, the Department agrees with the Attorney General that allowing carrying charges on the prepaid amounts is unreasonable.

Further, the Department finds that the actuarial assumptions determining the annual pension and PBOP expenses are not entirely outside of the Company's control. According to National Grid, it must develop two categories of the actuarial assumptions to determine the

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[121] "Write-down" is an accounting term to describe the presentation of a company's balance sheet. For example, under FAS 158, a company is required to report its benefit plan funded status in other comprehensive income, and the effect of such recording is described as a write-down to the equity in the event the company's benefit plan is underfunded (Exh. NG-P/PBOP-4, at 10).

[122] Write-off is the recognition of impairment of an asset that no longer exists, e.g., when a regulated utility carries a regulatory asset without a probable recovery, the regulatory asset would be written off (Exh. NG-P/PBOP-4, at 10-11).

pension liability and the annual expense (Exh. NG-P/PBOP-4, at 11). The Company selects assumptions as of the measurement date (i.e., March 31) to update the funded status on the balance sheet, which then are used for the subsequent fiscal year's expense, unless interim updates are required due to a significant event, such as settlement, curtailment, or a plan amendment (Exh. NG-P/PBOP-1, at 20). National Grid works with its actuaries to determine these assumptions, i.e., demographic and economic assumptions (Exh. NG-P/PBOP-4, at 11). The Company's pension delivery group summarizes the actuary's recommendations and independently reviews all major economic and demographic assumptions (Exh. NG-P/PBOP-1, at 21). There are key internal controls around the major economic assumptions (Exh. NG-P/PBOP-1, at 21). The demographic assumptions include turnover rates, retirement rates, mortality expectations, and marital status, and represent an expectation of the participants' future behavior (Exh. NG-P/PBOP-4, at 11). Demographic assumptions are typically updated every three to five years based on detailed studies of the Company's actual experience with its employees (Exh. NG-P/PBOP-4, at 11). As a result, the demographic assumptions tend to be very consistent over time and have little influence on the pension liability and the annual expense (Exh. NG-P/PBOP-4, at 11-12). The economic assumptions include discount rate, EROA, salary increases, inflation, and investment markets (Exhs. NG-P/PBOP-4, at 12; DPU 8-7).

The most significant assumption is the discount rate that, based on the ASC 715 definition, represents the rate at which the Company can settle its pension obligations defined by ASC 715 (Exhs. NG-P/PBOP-4, at 12, 15; DPU 8-7; DPU 8-8; Tr. 7, at 1039). As discussed above, National Grid contends that the selection of the discount rate is rule-based, largely dependent on rates available for high-quality fixed income investments like corporate bonds, and primarily outside of the Company's judgment and control (Exhs. NG-P/PBOP-4, at 12-13; AG 1-49, Att. 1, at 38, Att. 2, at 36, Att. 3, at 35, Att. 4, at 40-41; Tr. 7, at 1039; Tr. 8, at 1206). In particular, the Company states that the strict guidance from the U.S. Securities and Exchange Commission's ("SEC") and ASC 715 provides limited leeway for selecting the discount rate (Exhs. NG-P-PBOP-1, at 19-20; NG-P/PBOP-4, at 15). For example, based on the Willis Towers Watson-conducted global survey on the assumptions for defined benefit plans on December 31, 2023, the average discount rate for the participants in the United States is 5.21 percent, with the 25th percentile at 5.13 percent and 75th percentile at 5.28 percent (NG-P/PBOP-4, at 15). But in comparison with the Company's discount rate assumptions for the test year at 3.65 percent and 4.3 percent, the test-year assumptions are 156 basis points and 91 basis points lower than the surveyed average, and 157 basis points and 83 basis points lower than the surveyed 25th percentile discount rate (Exhs. NG-P/PBOP-4, at 15; AG 1-2, Att. 5, at 28; AG 1-49, Att. 4, at 116).[123] An additional comparison for the Company's discount rate assumption for fiscal year 2024 at 4.85 percent shows that the assumption is 36 basis points lower than the surveyed average and 28 basis points lower than the surveyed 25th percentile discount rate (Exh. NG-P/PBOP-4, at 15; RR-DPU-31, Att. 1, at 41).

We find that National Grid understates the degree of control it exercises over the discount that factors into plan assumptions. In setting the discount rate, National Grid's actuary takes its cash flows and puts them into a yield curve model that aggregates high-quality corporate bonds

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[123] Two discount rates at 3.65 percent and 4.3 percent were used for the evaluation of the Company's pension obligation and annual expense before and after the sale of Narragansett Electric Company on May 25, 2022 (Exh. AG 1-49, Att. 4, at 110). Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-03 (2023).

in the market as of the measurement date and matches them to determine the weighted average discount rate for the Company (Tr. 8, at 1190). Following National Grid's review of the inputs, and checking against external yield curve information, the Company's controller ultimately approves the discount rate (Exh. NG-P/PBOP-1, at 21; Tr. 8, at 1190-1191). If National Grid disagrees with the result provided by the actuary, the Company works with its actuary to come to a consensus for the input and output of the information (Tr. 8, at 1192).

The Department also finds that National Grid has a meaningful degree of control over plan assumptions related to EROA. National Grid's investment management team checks plan investment strategies against multiple long-term capital market outlook reports (Tr. 8, at 1193). The selection is ultimately approved by the Company's U.S. controller and U.S. treasurer (Exh. NG-P/PBOP-1, at 21; Tr. 8, at 1192-1194). These approved assumptions are then provided to the actuaries for the plan evaluation and determine the annual costs for its pension and PBOP plans (Exhs. NG-P/PBOP-1, at 21; NG-P/PBOP-4, at 14; Tr. 8, at 1194).

The Company states that, similar to the discount rate assumption, EROA is set in accordance with the guidance of SEC and generally accepted accounting principles, and also has a very tight bandwidth, as shown in the same Willis Towers Watson survey with the average at 6.23 percent for 2024 (unchanged from 2023), the 25th percentile at 5.7 percent, and the 75th percentile at 7 percent (Exh. NG-P/PBOP-4, at 15, 20).

The Department finds that the Company's EROA assumptions for the test year at 5.25 percent and 5.75 percent are 98 basis points and 48 basis points, respectively, below the surveyed average, and for the fiscal year 2024 at 6.5 percent above the surveyed average and under the 75th percentile assumption (Exhs. AG 1-2, Att. 5, at 28; AG 1-49, Att. 4, at 116;

RR-DPU-31, Att. 1, at 41). Moreover, the Department is not persuaded by the Company's contention that the EROA does not change significantly from year to year, considering that it has ranged from 5.25 percent to 6.5 percent between fiscal years 2020 through 2024, with a 50-basis point decrease each year from fiscal years 2020 through 2022, a 50-basis point increase during the test year from 5.25 percent to 5.75 percent, and a 75-basis point increase in fiscal year 2024 (Exhs. AG 1-2, Att. 5, at 28; AG 1-49, Att. 1, at 111, Att. 2, at 104, Att. 3, at 103, Att. 4, at 116; RR-DPU-31, Att. 1, at 41).[124] Therefore, although the Company does not have control over the interest rate of the high quality corporate bond rate, it does have the ability to select from a range of interest rates to apply to assumptions regarding pension and PBOP expenses.

The Department finds further support for this conclusion based on the Company's obligations under federal securities law regarding internal controls. The SEC requires registrants to provide an assessment of their internal controls over financial reporting (Exh. NG-P/PBOP-4, at 14). As a registrant, National Grid is obligated to maintain various controls, including detailed assessments and documentation of management's view and approval of all significant pension and PBOP plan assumptions (Exh. NG-P/PBOP-4, at 14). The Company's independent auditors must audit management's assessment and provide a report on the effectiveness of these controls each year to the SEC (Exhs. NG-P/PBOP-1, at 20; NG-P/PBOP-4, at 14). The Company states that the actuaries must perform their duties under Actuarial Standard of Practice 27, Selection of

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124 The Department notes that, unlike the actuarial reports usually dated in September before its fiscal year end and provided in its PAM filings, the Company's actuarial report for fiscal year 2024 is an updated version dated April 26, 2024, in which the Company provided its actuary with new demographic and economic assumptions (Exh. AG 1-49, Att. 1, at 110, Att. 2, at 104, Att. 3, at 101, Att. 4, at 110; RR-DPU-31, Att. 1, at 1-2).

Economic Assumptions for Pension Obligation, and Actuarial Standard of Practice 35, Section of Demographic and Other Noneconomic Assumptions for Measuring Pension Obligations (Exh. NG-P/PBOP-4, at 14). The Company's annual actuarial report states that, "National Grid USA selected the economic and demographic assumptions and prescribed them for purposes of compliance with ASC 715" (Exh. AG 1-49, Att. 1, at 181-182, Att. 2, at 102-103, Att. 3, at 192, Att. 4, at 250; RR-DPU-31, Att. 1, at 119). As such, the Department concludes that the assumptions used for determining FAS-determined pension and PBOP expenses are not entirely outside of the Company's control.

The Department recognizes that the Company does not have control over market conditions. Nonetheless, National Grid's pension expense overall has been less than one percent of the Company's revenue in the past five years (Exhs. DPU 48-6, Att.; AG 1-5, Att. 3, at 4, Att. 5, at 5; AG 29-8). The Department also recognizes that the Company has been making contributions to its pension fund even though the minimum required contribution has been zero since fiscal year 2021, which affects the evaluation of the pension obligation (Exhs. DPU 43-5; AG 29-3). Next, the Department is not convinced that changing the recovery method of pension and PBOP costs would have a negative impact on the Company and its customers. The Company states that recovering pension and PBOP costs through base distribution rates would serve to deny customers the benefits of negative FAS-determined pension and PBOP expenses that could occur based on demographic and economic assumption changes (Exh. DPU 8-7).[125]

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125 The Company's pension expense did not turn negative until fiscal year 2024 (Exhs. AG 1-49, Att. 1, at 112, Att. 2, at 104, Att. 3, at 103, Att. 4, at 116; AG 29-8; RR-DPU-31, Att. at 41).

The Company also states that it expects that the future pension expense will exceed the required contributions (Exh. NG-P/PBOP-1, at 33). While these statements are technically accurate, they do not justify cost recovery through a reconciliation mechanism.

National Grid's PAM revenues and expenses are both low in comparison to the Company's total revenues and expenses and relatively stable. National Grid's test year PAM revenues of $12,481,143 are about 0.44 percent of its total operating revenues of $2,847,886,522 (Exh. NG-RRP-2, Sch. 2, at 1 (Rev. 4)). In addition, the Company's residential PAM factors have ranged from $0.00087 per kWh to $0.00193 per kWh in the past five years. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-03, at 2 (2023); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-04, Exh. NG-2, at 1 (2022); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 21-02, at 2 (2021); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 20-05, at 2 (2020); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 19-03, Exh. JDO-2, at 1 (2019). Although there have been annual fluctuations, the PAM factors remained low over this period. In addition, the Company's pension expense has been less than one percent of its revenue and has ranged from 0.13 percent to 0.83 percent for the past five years (Exhs. AG 1-2, Att. 3, at 4, Att. 5, at 5, Att. 7, at 4, Att. 8, at 4, Att. 10, at 5; AG 29-8). Further, the Company's PAM revenue fluctuated less than 0.5 percent of the total operating revenues during the years of 2019 through 2022 (Exhs. DPU 8-7, Att.; AG 1-2, Att. 3, at 4, Att. 5, at 5, Att. 7, at 4, Att. 8, at 4, Att. 10, at 5).[126, 127] Additionally, even if the PAM was intended to address the volatility of expenses rather than revenues, the Company's pension and PBOP expenses have fluctuated less than 0.65 percent of its total operating expenses each year during fiscal years 2019 through 2022 (Exhs. DPU 48-6, Att.; AG 1-2, Att. 3, at 4, Att. 5, at 5, Att. 7, at 4, Att. 8, at 4, Att. 10, at 5).[128]

In sum, we find that it is appropriate to reapply traditional ratemaking principles to these expenses, rather than continuing the PAM. The Department's ratemaking is based on a historical test year to provide a representative level of a company's revenues and expenses which, when

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126 Fiscal Year 2019 – ($24,083,237 pension + $2,804,188 PBOP) / ($2,409,922,000 MECo + $21,877,000 Nantucket) = 1.116 percent.

Fiscal Year 2020 – ($13,798,532 pension + -$456,315 PBOP) / ($2,456,591,000 MECo + $22,073,000 Nantucket) = 0.538 percent.

Fiscal Year 2021 - ($23,378,904 pension + -$232,370 PBOP) / ($2,429,179,000 MECo + $25,966,000 Nantucket) = 0.943 percent.

Fiscal Year 2022 – ($17,836,801 pension + -$1,512,804 PBOP) / ($2,490,683,000 MECo + $26,217,000 Nantucket) = 0.649 percent.

127 The Department recognizes the sale of Narragansett Electric Company, which closed on May 25, 2022, required a revaluation of the pension obligation for fiscal year 2023. The comparison therefore does not include the test-year expense (Exhs. DPU 31-15; DPU 37-5; AG 1-49, Att. 4, at 116).

128 Fiscal Year 2019 – ($24,083,237 pension + $2,804,188 PBOP) / ($2,206,085,000 MECo + $15,172,000 Nantucket) = 1.21 percent.

Fiscal Year 2020 – ($13,798,532 pension + -$456,315 PBOP) / ($2,219,768,000 MECo + $14,765,000 Nantucket) = 0.596 percent.

Fiscal Year 2021 - ($23,378,904 pension + -$232,370 PBOP) / ($2,206,682,000 MECo + $17,185,000 Nantucket) = 1.041 percent.

Fiscal Year 2022 – ($17,836,801 pension + -$1,512,804 PBOP) / ($2,274,953,000 MECo + $17,030,000 Nantucket) = 0.717 percent.

adjusted for known and measurable changes, serve as a proxy for future operating results. D.T.E. 99-118, Interlocutory Order Regarding Scope of Proceeding and Motion to Compel Discovery at 8; Assabet Water Company, D.P.U. 95-92, at 28 (1996); Western Massachusetts Electric Company, D.P.U. 84-25, at 68-69 (1984); D.P.U. 1580, at 13-17; D.P.U. 1438/1595, at 3-4. While year-to-year changes in expenses are inevitable, the ratemaking process does not demand that all expenses be fully reconciled. In any given year, some expenses will increase, and other expenses will decrease. While base distribution rate recovery of pension and PBOP expenses may preclude customers from benefiting from year-to-year expense fluctuations, the Department is not persuaded that the yearly changes in National Grid's PAF factors are so unique as to consider these benefits significant in a meaningful way.[129]

b. Base Distribution Rate Recovery

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

129 National Grid's current average PAF is a negative $0.00116 per kWh. D.P.U. 24-03, Exh. NG-2, at 1. National Grid's average PAF factors for the years 2019 through 2023 ranged from a positive $0.00139 per kWh to a negative $0.00069 per kWh. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-02, Stamp Approval (December 28, 2023); D.P.U. 20-05, Stamp Approval (November 18, 2020); D.P.U. 19-03, Exh. JDO-2, at 1.

In deriving a representative level of pension and PBOP expenses, the Department has considered the FAS-determined pension and PBOP expenses. Specifically, National Grid presented its test-year pension expense of $12,326,361 in its cost of service (Exh. NG-RRP-2, Sch. 38 (Rev. 3)). During the proceeding, the Company presented differing amounts for the test-year pension expense varying from negative $4,448,279 to $12,326,361 (Exhs. NG-RRP-2, Sch. 37, 38 (Rev. 3); DPU 8-5, Att.; DPU 8-7, Att.; DPU 37-4, Att., at 1; DPU 48-6, Att.; AG 9-1, Att. 1 & Supp.; AG 29-8). The Company states that it is trying to be transparent about the expense allocated to different functions (Tr. 7, at 1017-1018). The Company also states that the amount shown in Exhibit NG-RRP-2, Schedule 38, at 3, line 3 (Rev. 3) adjusts for the difference between the actuarial result and the deferral and amortization amount (Tr. 7, at 1014-1015). According to the Company's actuarial report, the test-year amount is $2,074,353, which does not include the allocation from NGSC (Exh. AG 1-49, Att. 4, at 116).[130] The amount recorded in the Company's chart of accounts is $3,671,092 (Exh. AG 1-34, Att. 1-2). Based on the evidence, the Department concludes that the representative level cannot be based on FAS-determined pension and PBOP expenses.

The Department has held that the actual cash contribution to a tax-deductible trust strikes a balance between the interests of shareholders and ratepayers, in that this approach recognizes that utilities will incur benefit plan obligations, emphasizes the need to reduce overall benefit costs, ensures that ratepayer-supplied funds are retained to meet employee benefits, and matches

130 According to the actuarial report, the test-year pension expense decreased from $3,686,910 ($3,657,826 + $29,084) to $2,074,353 ($2,063,166 + $11,187) due to a reevaluation after the sale of Narragansett Electric Company on May 25, 2022 (Exhs. DPU 31-15; AG 1-49, Att. 4, at 116, 118).

employee benefits with the period in which they were earned. D.P.U. 95-40, at 49-40; D.P.U. 92-111, at 225-226; D.P.U. 92-78, at 83. National Grid has consistently made cash contributions to its pension and PBOP plans each year as of the test year (Exhs. DPU 43-5; DPU 43-6; AG 29-8). The Company's minimum required contribution has been zero since fiscal year 2021 (Exh. DPU 43-5). The Company's pension cash contributions have ranged between $0 and $18,755,000 during fiscal years 2020 through 2024, with a five-year average over that period of $12,383,600 (Exhs. DPU 43-5; AG 29-8). The Department is persuaded that sufficient volatility remains in National Grid's cash contributions to its pension plan to preclude the use of the Company's test-year pension expense (Exhs. DPU 43-5; AG 29-8). Accordingly, the Department will determine a representative level of pension expense.

The Department will base pension expense on the five-year average of the cash contributions for 2020 through 2024. D.P.U. 95-118, at 111. The Company's total cash contributions to its pension plan for the fiscal years 2020 through 2024 was $61,918,000, representing an average of $12,383,600 per year (Exhs. DPU 43-5; AG 29-8). Therefore, the Department allows $12,383,600 as a representative level of pension expense. Consistent with the pension expense, the Department will base PBOP expense on the five-year average of the cash contributions to its PBOP plan for fiscal years 2020 through 2024. D.P.U. 95-118, at 111. The Company's total PBOP contributions for the fiscal years 2020 through 2024 was $906,000 representing an average of $181,200 per year (Exhs. DPU 43-5; AG 29-8). Therefore, the Department allows $181,200 as a representative level of PBOP expense. Based on the above findings, the Department increases the Company's proposed cost of service by $12,564,800, based on the representative level of pension expense (i.e., $12,383,600) plus PBOP expense (i.e., $181,200).

The Department is not persuaded by the Company's and the Attorney General's arguments favoring a deferral of amounts over and under the representative amount for recovery in a future base distribution rate case (Company Brief at 46-47 (Supp.), citing Exh. DPU 52-3; Attorney General Brief at 9 (Supp.)). First, this requested treatment is inconsistent with the Department's traditional ratemaking relative to O&M expenses, as discussed above. Second, as the Department has determined that the representative level of expense is based on the five-year average of cash contributions and not the FAS-determined pension and PBOP expenses, a deferral in this instance is unnecessary. Specifically, the cash contributions and the FAS-determined expenses represent the same costs to pension and PBOP plans, and in this instance the cash contribution is recognized as the cost to pension and PBOP plans consistent with the Department's ratemaking to derive a representative level of expense to be included in rates. NSTAR Electric Company, D.P.U. 10-161, at 17 n.16 (2011); D.P.U. 96-50 (Phase I) at 50. See also Southern Union Company v. Department of Public Utilities, 456 Mass. 812, 823 (2011); Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 440 Mass. 625, 637 (2004); Boston Edison, 375 Mass. 1, 6. In addition, from an accounting perspective, the cash contribution is an immediate reduction to the pension and PBOP plan liabilities, while FAS-determined expenses are on a deferred basis; therefore, recognizing cash contributions as the costs to pension and PBOP plans requires no deferral treatment on the associated income taxes (Exhs. AG 29-1, Att. 1, at 4; AG 29-1, Att. 2, at 3-4). Third, as discussed in Section IV.C. above, the Department has approved the Company's proposed PBR-O, with certain modifications. We expect that the PBR-O mechanism will allow the Company to recover some of the difference between the representative levels of expenses (including, but not limited to, pension and PBOP expenses) and actual, incurred expenses. Thus, we find that special ratemaking treatment in the form of a deferral is unnecessary.

Regarding carrying charges on prepaid pension and PBOP balances, as of the end of the test year, National Grid reported a total prepaid pension balance of $141,250,912 and a total prepaid PBOP balance of $41,211,916; these amounts exclude prepaid pension and PBOP associated with energy efficiency and allocations from NGSC (Exh. DPU 31-7 & Att.).[131] National Grid states that because its prepaid pension and PBOP balances are supported by the Company's capitalization and financed by its overall capital structure and further that its cash flow is lower in years where pension expense is less than plan contributions, the Company requires compensation for the associated financing costs (Exh. NG-P/PBOP-1, at 31). The Department has generally not allowed the recovery of carrying charges on prepaid balances because of the difficulty in ascertaining whether ratepayers benefit from the prepayments. Western Massachusetts Electric Company, D.P.U. 84-25, at 59-61 (1984).[132] We identify some

131 While the Company's general ledger and chart of accounts do not explicitly provide prepaid pension and prepaid PBOP, these prepaid balances are calculated each year by adding contributions and FAS-determined pension and PBOP expense to the previous year's cumulative balance (Exh. DPU 31-8).

132 Although Western Massachusetts Electric Company was allowed to recover carrying charges on its average prepaid pension and PBOP balances in rate base in Western Massachusetts Electric Company, D.T.E. 06-55, at 4-5 (2006), that provision was part of a settlement between that company and the Attorney General involving, in relevant part, the implementation of a pension and PBOP reconciliation mechanism. Settlements have no precedential value. Barnstable Water Company, D.P.U. 91-189, at 6 n.3 (1992); Dover Water Company, D.P.U. 90-86, at 4 (1990).

differences from the carrying charges the Department approved for recovery through the local distribution adjustment clause in D.T.E. 03-40, at 311-314. The Department's decision in D.T.E. 03-40, at 311, was influenced by poor market performance over the preceding several years, coupled with an extraordinary decline in interest rates, thus requiring companies to make even greater contributions to fund their pension plans. Since 2003, prefunding requirements have been incorporated into the FAS 158 funded status, and consequently pension and PBOP expenses will now be recovered through future FAS-determined expenses (Exhs. NG-P/PBOP-4, at 10; DPU 31-8).[133] On this basis, the Department finds it unnecessary to provide for carrying charges on the Company's pension and PBOP balances. Therefore, the Department declines to adopt the Company's alternative proposal to include pension and PBOP balances in rate base.

c. PAM Phase Out and Discontinuance

The Company's current pension and PBOP cost recovery through the PAM operates on a three-year deferral basis, and the Company recovers a base amount and one-third of the deferred under- or over-recovery each year. See generally D.P.U. 24-03; D.P.U. 23-03; D.P.U. 22-04; D.P.U. 21-02. Given this treatment, we find that it is appropriate to provide the following guidance for discontinuing the PAM.

The Department permits the Company to recover the remaining balance of the unamortized pension and PBOP expenses through the next PAM filing. The total unamortized balance shall include: (1) the unamortized pension and PBOP expense deferral as of September 30, 2024; (2) the true up of the calendar year 2024 pension and PBOP expenses; and

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133 Prefunding, i.e., prepaid amount, is the accumulated cash contribution subtracts the accumulated FAS-determined expenses (Exhs. DPU 31-8; DPU 48-2).

(3) the under- or over-recovery through the Company's PAF as of the reconciliation date. The unamortized pension and PBOP expense deferral as of September 30, 2024 is the amount of unamortized reconciliation deferral as of September 30, 2023, subtracting the amount of the Company's reconciliation adjustment for 2024 as filed in D.P.U. 24-03, Exh. NG-2, at 2, Lines 8, 9. The true-up of the calendar year 2024 pension and PBOP expenses is the actual calendar year 2024 pension and PBOP expense subtracting the calendar year 2024 pension and PBOP expenses as filed in D.P.U. 24-03, Exh. NG-2, at 2, Line 1. The under- or over-recovery through the Company's PAF as of September 30, 2024 will be calculated on the prime rate filed in the next PAM filing as illustrated in D.P.U. 24-03, Exh. NG-2, at 12. 220 CMR 6.08.

In addition, the Department directs the Company in its next PAM filing to reduce the calendar year 2024 pension and PBOP expenses by three months representing the pension and PBOP expenses for the duration of October 1, 2024 through December 31, 2024, calculated as three-twelfths of the amount filed in D.P.U. 24-03, Exh. NG-2, at 2, Line 1. Beginning from the next PAM filing, the Company will no longer recover carrying charges on prepaid pension and PBOP amounts in accordance with the Department's findings above. National Grid shall keep contemporaneous records for the PAM phase-out period for the Department's review in the Company's next base distribution rate case. The Company shall file a compliance filing with revised tariffs to become effective October 1, 2024, consistent with the directives in this Order.

L. Inflation Allowance

1. Introduction

National Grid proposes an inflation allowance of $9,084,079 (Exh. NG-RRP-2, Sch. 3, at 8 (Rev. 4)). To arrive at the proposed inflation allowance, the Company took its adjusted test-year O&M expense of $527,642,521 and subtracted $391,867,506 in test-year expenses associated with the various O&M expenses items for which the Company seeks separate adjustments, which produced a test-year residual O&M expense of $135,775,014 (Exhs. NG-RRP-1, at 22-23; NG-RRP-2, Sch. 3, at 8 (Rev. 4)). National Grid then calculated a proposed inflation factor of 6.45 percent using the most recent forecast of the gross domestic product chain-type price index ("GDPCTPI") based on data from the U.S. Bureau of Economic Analysis and Moody's Analytics from the end of the test year (i.e., March 31, 2023) to the end of the rate year (i.e., September 30, 2025) (Exhs. NG-RRP-1, at 22-23; NG-RRP-2, Sch. 3, at 9 (Rev. 4)). National Grid multiplied the 6.45 percent inflation factor by the test-year residual O&M expenses of $135,775,014 to arrive at a proposed inflation allowance of $8,757,488 (Exh. NG-RRP-2, Sch. 3, at 8 (Rev. 4)). In addition, National Grid calculated a separate inflation amount of $326,590 applicable to its environmental response fund by multiplying its environmental response fund contribution of $5,231,340 by an annual inflation factor of 6.24 percent (Exh. NG-RRP-2, Sch. 3, at 8 (Rev. 4)).[134] The sum of these two inflation components produced a total proposed inflation allowance of $9,084,079 (Exh. NG-RRP-2, Sch. 3, at 8 (Rev. 4)).

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[134] Pursuant to the terms of a settlement in Massachusetts Electric Company, D.P.U. 93-194 (1994), National Grid is permitted to increase its annual contribution to the environmental response fund on October 1 of each year, equal to the rate of inflation based on the gross domestic product implicit price deflator (Exh. NG-RRP-1, at 57). See also D.P.U. 15-155, at 308-313.

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General does not disagree with the Company's calculation of its inflation allowance but recommends removing the inflation escalation as it pertains to group life and other insurance expense, joint facilities expense, uninsured claims, consultant expenses, and contractor expenses (Attorney General Brief at 106). The Attorney General's proposals are set forth in detail below.

ii. Group Life and Other Insurance

The Attorney General recommends that the Department exclude the Company's proposed inflation adjustment of $9,476[135] associated with group life and other insurance expense (Attorney General Brief at 107; Attorney General Reply Brief at 25-26). According to the Attorney General, this expense is associated with the Company's absence management program and consists of a flat rate cost plus disability payments issued to employees through a third-party vendor (Attorney General Brief at 108, citing Exh. NG-RRP-Rebuttal-1, at 5). In support of her position, the Attorney General first argues that the flat rate component should not be adjusted for inflation because National Grid failed to demonstrate that these costs follow inflationary trends, and the Company did not offer any other justification for escalating this component (Attorney General Brief at 108). Second, she argues that the disability payments issued to employees should not be adjusted for inflation because these payments are not known and measurable

[135] This amount was revised to $9,520 based on the Company's final cost-of-service update (Exh. NG-RRP-2, Sch. 3, at 4 (Rev. 4)).

expenses driven by inflation (Attorney General Brief at 108). The Attorney General also contends that the fact that disability payments may be impacted by payroll (which, in turn, is subject to increases through the labor inflation rate) is insufficient to qualify the expense for the inflation adjustment, as disability payments tend to vary year to year depending on the number of disability claims and the nature of the claims (Attorney General Brief at 108).

iii. Joint Facilities

The Attorney General argues that the Department should exclude the Company's proposed inflation adjustment of $96,028[136] associated with joint facilities[137] (Attorney General Brief at 108; Attorney General Reply Brief at 26). The Attorney General contends that even if this expense category is subject to inflationary pressures, that fact alone is insufficient to qualify for the inflation adjustment (Attorney General Brief at 109). In support of her position, the Attorney General claims that the Company's annual joint facilities expense for the years 2018 through 2022, as well as the test year expense, demonstrates that joint facilities expenses will vary year to year depending on the joint facilities in use (Attorney General Brief at 109, citing Exhs. NG-RRP-Rebuttal-1, at 6; AG 7-39). According to the Attorney General, any normalizing adjustment to this expense is irrelevant to whether an inflation allowance is warranted (Attorney General Brief at 110).

136 The Company subsequently revised this amount to $94,476 (Exh. NG-RRP-2, Sch. 3, at 4 (Rev. 4)).

137 Joint facilities are the physical operating facilities owned by the Company's affiliates and used to provide service to customers.

In addition to her expense variation claim, the Attorney General argues that the Company's joint facilities expense warrants separate examination outside of the inflation allowance (Attorney General Brief at 109; Attorney General Reply Brief at 26, citing D.T.E. 02-24/25, at 184). The Attorney General notes that changes in the accounting treatment of rent expense at the Company's Northborough facility resulted in a 50-percent decrease in joint facilities expense, which the Attorney General considers large enough to warrant the separate treatment of joint facilities expense apart from the inflation allowance[138] (Attorney General Brief at 109, citing Exh. NG-RRP-Rebuttal-1, at 7-8; Attorney General Reply Brief at 26, citing D.T.E. 02-24/25, at 184). Based on the above reasons, the Attorney General asserts that the Company's joint facilities expense is not eligible for an inflation allowance (Attorney General Brief at 110; Attorney General Reply Brief at 26).

iv. Uninsured Claims

The Attorney General recommends that the Department exclude the Company's proposed inflation adjustment of $209,417[139] associated with uninsured claims (Attorney General Brief at 112; Attorney General Reply Brief at 26). She disputes the Company's notion that inflation affects the cost of repairs to and replacement of damaged items, and awards by jury verdicts on bodily injury lawsuits have been increasing (Attorney General Brief at 110, citing

138 During 2022, National Grid changed the accounting treatment associated with the Company's Northborough facility to eliminate the previous practice where the Company would self-charge its distribution segment for rent associated with that facility (Exh. NG-RRP-Rebuttal-1, at 7-8).

139 The Company subsequently revised this amount to $210,395 (Exh. NG-RRP-2, Sch. 3, at 4 (Rev. 4)).

Exh. NG-RRP-Rebuttal-1, at 8-9). The Attorney General argues that the fact that inflation may influence repairs and replacements costs is insufficient to qualify for the inflation adjustment (Attorney General Brief at 111). Second, she argues that jury verdict awards on bodily injury lawsuits are irrelevant to whether an inflation adjustment is warranted, because these overall costs are still largely dependent on the number of claims, the number of cases that go to trial, and the number of cases in which jury decides to grant a monetary award (Attorney General Brief at 111). Moreover, the Attorney General notes that a large jury verdict could likely constitute a single expense large enough to warrant separate ratemaking treatment outside of the inflation allowance (Attorney General Brief at 111).

The Attorney General also points to the Company's annual uninsured claims expense for the years 2018 through 2022, as well as the test year, and contends that the year-to-year variation in expense demonstrates that uninsured claims vary significantly from year to year and are thus not eligible for an inflation allowance (Attorney General Brief at 113-114, citing Exh. AG 7-39). Similar to her argument above, the Attorney General asserts that normalization of the uninsured claims expense is irrelevant to the inflation allowance issues (Attorney General Brief at 111-112; Attorney General Reply Brief at 25-26).

v. Consultants and Contractors

The Attorney General recommends that the Department exclude the Company's proposed inflation adjustment of $1,496,369[140] associated with consultant expenses and $3,166,350[141] associated with contractor expenses (Attorney General Brief at 112-114; Attorney General Reply Brief at 26). She contends that the Company's annual contractor expense for the years 2018 through 2022, as well as the test year, vary year to year depending on Company's needs and, therefore, these expenses are not eligible for an inflation allowance (Attorney General Brief at 112-114, citing Exh. AG 7-39). Again, the Attorney General asserts that normalization of these expenses is unnecessary and irrelevant to determining whether they should be removed from the inflation allowance (Attorney General Brief at 113-114, citing Exh. AG 7-39; Attorney General Reply Brief at 25-26).

b. Company

National Grid argues that its application of an inflation adjustment factor to residual O&M expenses is consistent with the Department's practice in previous rate case proceedings, including the Company's prior rate case (Company Brief at 345; Company Reply Brief at 48). Further, the Company contends that the Department has consistently approved inflation adjustments for the categories challenged by the Attorney General (Company Brief at 353; Company Reply Brief at 48-49, citing D.P.U. 20-120, at 529; D.P.U. 18-150, at 575;

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140 The Company subsequently revised this amount to $1,503,360 (Exh. NG-RRP-2, Sch. 3, at 4 (Rev. 4)).

141 This amount was revised to $3,181,146 based on Exhibit NG-RRP-2, Sch. 3, at 4 (Rev. 4).

D.P.U. 17-170, at 151; D.P.U. 10-55, at 272). National Grid asserts that the Attorney General's recommendations should be denied in the absence of proper analysis or other information to adequately explain why the inflation adjustments associated with these expenses should be excluded from the Company's cost of service (Company Brief at 352). In particular, the Company argues that the Attorney General's reliance on unadjusted expense data is flawed and can mask the inflationary pressures that can affect these operating expenses (Company Reply Brief at 49, citing Exh. AG 7-39). The Company's specific arguments regarding the contested residual O&M expense items are provided below.

i. Group Life and Other Insurance

National Grid argues that disability payments are influenced by underlying increases in payroll expense, such as increases in headcount and salaries and, therefore, the Company could have increased these expenses by the labor inflation rate, which would have resulted in higher rate-year expenses (Company Brief at 353). The Company contends, however, that it decided to apply an inflation adjustment consistent with prior base distribution rate cases, including National Grid proceedings (Company Brief at 353-354, citing D.P.U. 20-120; D.P.U. 18-150; D.P.U. 17-170).

ii. Joint Facilities

National Grid contends that the inclusion of an inflation allowance for joint facilities is consistent with Department precedent and the expense is not otherwise adjusted for purposes of determining the Company's revenue requirement to reflect rate-year conditions (Company Brief at 354-355 & n.82, citing D.P.U. 20-120, at 529; D.P.U. 18-150, at 575). The Company further argues that despite the use of normalizing adjustments, normalized joint facilities expense nonetheless remain subject to inflationary pressures (Company Brief at 354 & n.81, citing Exhs. NG-RRP-Rebuttal-1, at 7; AG 7-39, Att.). National Grid attributes a decrease in joint facilities costs in 2022 to a change in the accounting treatment of MECo's Northborough facility, whereby MECo ceased its former practice of self-charging its distribution segment for rent from the facility (Company Brief at 355, citing Exhs. NG-RRP-Rebuttal-1, at 7; AG 7-39, Att.). Further, National Grid asserts that regardless of the change in accounting treatment, the Company removed the rent amount associated with the Northborough facility as a normalizing adjustment to the Company's test-year amount (Company Brief at 355).

iii. Uninsured Claims

National Grid argues that the Attorney General is mistaken in her contention that uninsured claims vary by the number of claims (Company Brief at 356). First, National Grid contends that the Attorney General erroneously relies on unnormalized data, which ignores the fact that in fiscal years 2022 and 2023, the Company made two adjustments to its incurred but not reported uninsured claim reserve, which resulted in decreases to uninsured claims in both calendar year 2022 and in the unadjusted test year (Company Brief at 356, citing Exhs. NG-RRP-Rebuttal-1, at 8-9; DPU 2-12; AG 7-39; AG 10-26). Second, the Company maintains that consistent with prior Department decisions, it adjusted the test-year uninsured claims expense included in the revenue requirement to reflect the five-year average actual claims paid, but it did not otherwise adjust this account to reflect rate-year conditions (Company Brief at 356, citing Exh. NG-RRP-2, Sch. 19, at 4 (Rev. 3)). Nevertheless, National Grid argues that it is appropriate to apply an inflation adjustment to uninsured claims because inflation pressures ultimately affect the cost of repairing and replacing damaged equipment, and the level of jury verdicts on bodily injury lawsuits have been increasing (Company Brief at 356, citing Exh. AG 10-26). Third, National Grid argues that its proposed inflation adjustment is consistent with the Department's decisions in the Company's prior base distribution rate case (Company Brief at 356, citing D.P.U. 18-150, Exh. NG-RRP-2(c), Sch. 19, at 3, line 18).

iv. Consultants and Contractors

National Grid argues that consultant costs vary in response to inflationary pressures and are not just based on the number of activities that involve the use of consultants (Company Brief at 357). Regarding the fluctuation in consultant costs, National Grid explains that it made several normalizing adjustments to test-year consultant expenses to redistribute major storm costs, redistribute expense credits due to the capitalization of administrative and general ("A&G") expenses that are primarily related to items that were capitalized on the Company's books, and removed expenses associated with non-base rate mechanisms, among other adjustments (Company Brief at 357, citing Exh. NG-RRP-1, at 48). According to the Company, the resulting normalized test year provides a reasonable cost foundation upon which to apply rate-year adjustments as opposed to relying on non-normalized costs, which can include costs associated with other recovery mechanisms, such as Grid Modernization (Company Brief at 357, citing Exh. NG-RRP-1, at 48). Further, National Grid argues that the application of an inflation adjustment to consultant costs is consistent with prior Department decisions where consultant costs were included as part of the Company's residual O&M expenses (Company Brief at 357-358, citing D.P.U. 20-120, at 579; D.P.U. 18-150, at 529).

Likewise, National Grid argues that contractor costs in any given year are affected by the level of storm costs incurred in that year (Company Brief at 358-359, citing

Exh. NG-RRP-Rebuttal-1, at 12-13). Further, National Grid contends that as contractor rates and wages continue to rise, the application of the inflation adjustment will provide the Company an opportunity to recover those increased costs during the proposed five-year rate plan (Company Brief at 359). Finally, the Company asserts that the application of an inflation adjustment to contractor costs is consistent with prior Department decisions where contractor costs were included as part of a company's residual O&M expenses (Company Brief at 359 & nn.87, 88, citing D.P.U. 20-120, at 575; D.P.U. 18-150, at 529).

3. Analysis and Findings

The inflation allowance recognizes that known inflationary pressures tend to affect a company's expenses in a manner that can be measured reasonably. D.T.E. 02-24/25, at 184; D.T.E. 01-56, at 71; D.T.E. 98-51, at 100-101; D.P.U. 96-50 (Phase I) at 112-113. The inflation allowance is intended to adjust certain O&M expenses for inflation where the expenses are heterogeneous in nature and include no single expense large enough to warrant specific focus and effort in adjusting. D.P.U. 1720, at 19-21. The Department permits utilities to increase their test-year residual O&M expense by an independently published price index from the midpoint of the test year to the midpoint of the rate year. D.P.U. 08-35, at 154-155; D.T.E. 02-24/25, at 184; D.P.U. 95-40, at 64; D.P.U. 92-250, at 97-98. For the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. D.P.U. 09-30, at 285; D.P.U. 08-35, at 154; D.T.E. 02-24/25, at 184.

National Grid calculated its proposed inflation factor of 6.45 percent from the end of the test year to the end of the rate year, using the most recent GDPCTPI as an inflation measure (Exhs. NG-RRP-1, at 22-23; NG-RRP-2, Sch. 3, at 9 (Rev. 4)). While the Department has accepted the use of various inflation indices for purposes of determining the inflation allowance, the Company's calculation method is inconsistent with Department precedent. As noted above, the inflation allowance is measured from the midpoint of the test year (in this case, September 30, 2022) through the midpoint of the rate year (in this case, March 31, 2025), not the end of the test year and end of the rate year.

The Department has examined the GDPCTPI data provided by the Company. Using the GDPCTPI data provided in Exhibit DPU 28-2, and the Company's computation method provided in Exhibit NG-RRP-3, Schedule 3, the Department calculates a historical GDPCTPI index value of 118.98 for the four quarters ending September 30, 2022, and a forecast GDPCTPI index value of 126.68 for the four quarters ending March 31, 2025. The application of these index values to the Company's computation method produces an inflation factor of 6.47 percent (see Exh. NG-RRP-2, Sch. 3, at 9 (Rev. 4)). Therefore, the Department applies an inflation factor of 6.47 percent.

With respect to cost containment, National Grid has demonstrated cost containment measures associated with the Company's residual O&M accounts. These efforts include seeking cost savings through productivity improvements such as customer-related self-service in the Company's web portals, enhanced coaching and performance management, and digital services for C&I customers with an emphasis on self-service features, as well as efficiency savings impacting certain contractors, transportation costs for fleet and fuel, materials, and property management (Exh. DPU 28-3 & Att.). Based on these considerations, the Department finds that National Grid demonstrated that it has implemented cost containment measures sufficient to qualify it for an inflation allowance.

If an O&M expense has been adjusted or disallowed for ratemaking purposes such that the adjusted expense is representative of costs to be incurred in the year following new rates, the expense is also removed in its entirety from the inflation allowance. D.P.U. 09-39, at 322; D.T.E. 05-27, at 204; D.T.E. 02-24/25, at 184-185; Blackstone Gas Company, D.T.E. 01-50, at 19 (2001); D.P.U. 88-67 (Phase I) at 141; Commonwealth Gas Company, D.P.U. 87-122, at 82 (1987). To calculate the inflation allowance, National Grid reduced its test-year O&M expense for various expense categories (Exh. NG-RRP-2, Sch. 3, at 8 (Rev. 4)). The Department accepts these adjustments subject to our findings below. Additionally, the Department has excluded from the residual O&M expense the disallowed test-year costs associated with memberships and dues expense and the portion of disallowed test-year costs related to the Company's Appreciate Program, as described above in this Order. The Department has also included in the residual O&M expense the test-year costs associated with the Company's enhanced vegetation management ("EVM") Pilot (see Section IX.D. below).

Regarding the issue of whether it is appropriate to allow an inflation adjustment for the operating expenses contested by the Attorney General (i.e., group life and other insurance expense, joint facilities expense, uninsured claims, consultant expenses, and contractor expenses), the Department is not persuaded by the Attorney General's argument that these expenses are not impacted by inflationary pressures and therefore unsuitable for the application of an inflation adjustment. While the Attorney General's reliance on historical expense data is useful in identifying expense categories that warrant closer examination, the data is insufficient to draw conclusions as to whether a particular expense is eligible for an inflation allowance (Exh. AG 7-39).

Further, our decision is based on the recognition that these types of operating expenses are prone to inflationary pressures and the record shows that they have not been adjusted for other known changes in this proceeding. For example, the decrease in joint facilities costs during 2022 is attributable to the accounting treatment of rent associated with the Company's Northborough facility (Exh. NG-RRP-Rebuttal-1, at 7). Likewise, the decrease in consultant costs during the test year is attributable to various accounting adjustments made during the test year (Exh. NG-RRP-1, at 48). In addition, the Department notes that while consultant and contractor costs will inevitably vary depending upon the level of activity, consulting firms and contractors are also subject to inflationary pressures and, allowing for competitive pressures, will incorporate those inflationary changes in their own pricing structures (Exhs. NG-RRP-1, at 48; NG-RRP-Rebuttal-1, at 12-13).

Based on the foregoing analysis, the Department finds insufficient record evidence to support the Attorney General's position that the contested expense items should be excluded from inflation adjustments. The Department finds that that the cost associated with the operating expenses discussed above are prone to inflationary pressures and have not been adjusted for other known changes. On this basis, the Department declines to accept the Attorney General's recommendations, and will allow the inflation adjustments associated with these accounts in the Company's cost of service by retaining these expenses in the residual O&M balance. The Department finds that an inflation allowance, equal to the most recent forecast of GDPCTPI for the period determined by the Department, applied to National Grid's approved level of residual O&M expense is appropriate. The approved inflation allowance and impact on the cost of service is shown in Schedule 2A below.

VII. EXCESS ACCUMULATED DEFERRED INCOME TAXES

A. Introduction and Relevant Procedural History

On December 22, 2017, the Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97 ("2017 Tax Act") was signed into law. Among other things, the 2017 Tax Act reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. On February 2, 2018, the Department, pursuant to G.L. c. 164, §§ 76, 93, 94 and G.L. c. 165, §§ 2, 4, opened an investigation into the effect on rates of the decrease in the federal corporate income tax rate on the Department's regulated utilities. D.P.U. 18-15, Order Opening Investigation.[142] 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.

On December 21, 2018, the Department issued an Order addressing, among other things, National Grid's proposal to refund excess ADIT to ratepayers. D.P.U. 18-15-E. In particular, the Department accepted National Grid's estimated total excess ADIT balance of $247,688,553 (before tax gross-up) and accepted National Grid's proposal to amortize all protected plant-related excess ADIT over an estimated 50-year average service life and to amortize all unprotected excess ADIT over a 21-year period for MECo and a 28-year period for Nantucket

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

Electric. D.P.U. 18-15-E at 34-35. Further, the Department directed National Grid to return the total estimated excess ADIT amount to ratepayers through a "2017 Tax Act Credit Factor" ("TACF") to be included as a separate reconciling component in the Company's annual reconciliation filing. D.P.U. 18-15-E at 35. The Department determined that the credit factor would remain in effect until the excess ADIT balance is transferred to the new base distribution rates established in its next base distribution rate proceeding, unless the Department ordered otherwise. D.P.U. 18-15-E at 36 n.31.

In addition, to the extent that National Grid's total estimated excess ADIT included amounts specifically associated with reconciling mechanisms, the Department directed the Company to return those amounts through the respective reconciling mechanism and adjust the total excess ADIT balance accordingly. D.P.U. 18-15-E at 36.[143] The Department also recognized that the estimated total excess ADIT amounts were subject to reconciliation once audited financial statements for its fiscal year ended March 31, 2018 were completed and once the Company determined the precise accounting method it must use to comply with the implications of the 2017 Tax Act. D.P.U. 18-15-E at 12 n.15, 35. The Department noted that it expected National Grid to make these determinations as soon as practicable and to implement appropriate adjustments, supported by testimony and exhibits, in future reconciliation filings. D.P.U. 18-15-E at 35.

143 The Department determined that this directive would remain in effect until the Company's next base distribution rate proceeding, unless otherwise directed by the Department. D.P.U. 18-15-E at 36 n.32. Further, the Department directed National Grid to itemize all ADIT amounts associated with specific reconciling mechanisms in its annual reconciliation filing. D.P.U. 18-15-E at 36 n.32.

During the compliance phase of D.P.U. 18-15-E, National Grid updated its total excess ADIT balance to align with its then recently filed income tax returns and to remove from the 2017 Tax Credit Factor amounts associated with specific reconciling mechanisms. D.P.U. 18-15-E, Compliance Filing at 2 & Att. 1 (Rev.) (January 15, 2019).[144] With respect to the amounts of excess ADIT associated with reconciling mechanisms, the Company proposed to credit customers nine-twelfths of the annual amortization of excess ADIT attributable to each particular mechanism over the time period between the effective date of the reconciling factor and November 1, 2019, which is the date that new base distribution rates took effect in the prior base distribution rate case, D.P.U. 18-150. D.P.U. 18-15-E, Compliance Filing at 2. National Grid also proposed that, effective November 1, 2019, it would remove the amortization of excess ADIT from each of the Company's reconciling factors (with the exception of the pension adjustment factor) and credit the remaining excess ADIT to customers through base distribution rates. D.P.U. 18-15-E, Compliance Filing at 2.

On January 28, 2019, the Department approved National Grid's proposed Tax Credit Provision tariff, M.D.P.U. No. 1403. D.P.U. 18-15-E, Stamp Approval (January 28, 2019). The Department determined that it would investigate in D.P.U. 18-150 the Company's proposal to remove the amortization of excess ADIT associated with any reconciling mechanism from that mechanism and credit the remaining amounts through base distribution rates effective November 1, 2019. D.P.U. 18-15-E, Stamp Approval, Hearing Officer Memorandum (January 28, 2019). Subsequently, in the Company's annual retail rate filing, the Department

144 The Company reported a revised total excess ADIT balance of $263,806,740. D.P.U. 18-15-E, Compliance Filing, Att. 1, at 2.

approved the Company's credit of excess ADIT for the period of January 1, 2019 through September 30, 2019. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 19-05-A at 5 (June 17, 2019). The Department also determined that it would investigate in D.P.U. 18-150 the propriety of crediting the remainder of the excess ADIT through base distribution rates. D.P.U. 19-05-A.

In National Grid's prior base distribution rate proceeding, the Company provided what it considered to be its excess ADIT balance as of September 30, 2019, of $259,796,675. D.P.U. 18-150, at 183. The balance was composed of $218,740,467 in protected plant-related excess ADIT; $42,930,674 NOL balance, which the Company proposed to apply as an offset to the protected plant-related excess ADIT; $67,843,677 in unprotected plant-related excess ADIT; $15,122,667 in unprotected non-plant-related excess ADIT; and $1,020,538 in unprotected excess ADIT associated with NGSC. D.P.U. 18-150, at 183. The Department approved the excess ADIT balance of $259,796,675 for purposes of calculating the annual amortization amount to refund to ratepayers. D.P.U. 18-150, at 192. From this amount, the Department removed $625,533 associated with the Company's grid modernization pilot program, and we directed the Company to retain the TACF and through it refund the remaining $259,171,142. D.P.U. 18-150, at 197-198, 200-201. The Department found that the excess ADIT balances were to be amortized over an average of 39 years for protected plant-related excess ADIT; 20.1 years for unprotected plant-related excess ADIT; five years for unprotected non-plant-related excess ADIT; and 9.3 years for NGSC-related excess ADIT. D.P.U. 18-150, at 183, 192-195.

On May 7, 2019, the IRS issued Notice 2019-33, a request for comments on necessary clarifications to normalize requirements for excess tax reserves resulting from the corporate tax rate decrease. The Department approved the Company's proposed amortization period for the NOL balance subject to anticipated clarification on normalization rules from the IRS. D.P.U. 18-150, at 195-198.

B. Company Proposal

In its initial filing, National Grid proposed an annual excess ADIT amortization of $3,451,293 to be included in base distribution rates, based on an excess ADIT balance of $226,623,669 at test year end (Exhs. NG-RRP-2, Sch. 10, at 2; NG-RRP-2, Sch. 11, at 4). During the proceeding, the Company updated its annual amortization amount to $3,964,393 based on its final total excess ADIT balance of $227,241,703 at test year end (Exhs. NG-RRP-2, Sch. 10, at 2 (Rev. 4); NG-RRP-2, Sch. 11, at 4 (Rev. 4)). The Company proposes to end its TACF and refund the remaining excess ADIT balances through base distribution rates beginning on October 1, 2024 (Exhs. NG-RRP-1, at 88; DPU 8-16). National Grid proposes to continue refunding the excess ADIT according to the amortization schedule the Department approved in D.P.U. 18-150 (Exhs. NG-RRP-1, at 88; DPU 8-16). The Company proposes the following annual amortization amounts based on the approved amortization periods: (1) $5,812,917 for protected plant-related excess ADIT; (2) $3,241,912 for unprotected plant-related excess ADIT; (3) $513,100 for unprotected non-plant-related excess ADIT; and (4) $110,328 for unprotected NGSC-related excess ADIT (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)). The sum of these amortizations equals a total proposed annual excess ADIT amortization of $9,678,258 (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)).[145]

C. Positions of the Parties

National Grid asserts that it reduced its federal income tax liability in accordance with the 2017 Tax Act and recorded a regulatory liability to refund to customers the reduced tax rate benefit (Company Brief at 274, citing Exh. NG-RRP-1, at 87). The Company maintains that the excess ADIT is properly segregated between protected and unprotected plant-related, unprotected non-plant-related balances, and NOL attributable to the plant-related excess ADIT (Company Brief at 274, citing Exh. NG-RRP-1, at 87). Further, the Company asserts that the NOL is considered protected because it results from plant-related book to tax timing differences (Company Brief at 274, citing Exh. NG-RRP-1, at 87). National Grid argues that unlike in D.P.U. 18-150, it does not anticipate additional changes or clarifications on the IRS normalization rules, and therefore proposes to roll the TACF into base distribution rates in the instant proceeding to refund the excess ADIT balance through base rates, with the continuation of the amortization schedules the Department approved in its prior rate case, D.P.U. 18-150 (Company Brief at 274-275, citing Exhs. NG-RRP-1, at 88; DPU 8-17). No other party addressed the Company's excess ADIT on brief.

145 As part of the excess ADIT amortization proposal, National Grid included the amount of negative $5,713,865, representing the annual amortization of the excess ADIT related to NOL (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)).

D. Analysis and Findings

1. Introduction

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

During the proceeding, National Grid stated that it updated the total excess ADIT balance to $227,241,703 as of test year end to reflect the IRS audit results on the Company's federal income tax returns for fiscal years 2010 through 2018 (Exhs. NG-RRP-2, Sch. 11, at 4; NG-RRP-2, Sch. 11, at 4 (Rev. 4); DPU 8-14; DPU 8-17 & Att.; DPU 31-29 & Att.; Tr. 7, at 997-998; RR-DPU-26 & Att.; RR-DPU-27 & Att.). D.P.U. 18-150, at 183, 192. The Department previously recognized that National Grid's estimated total excess ADIT amounts were subject to reconciliation once audited financial statements for its fiscal year ended March 31, 2018, were completed and once the Company determined the precise accounting method it must use to comply with the implications of the 2017 Tax Act. D.P.U. 18-15-E at 12 n.15, 35. The Company's proposed excess ADIT balance as of the test year end consists of $199,387,090 in protected plant-related excess ADIT; negative $30,824,663 in NOL; $50,897,237 in unprotected plant-related excess ADIT; $7,147,651 in unprotected non-plant-related excess ADIT; and $634,388 in NGSC-related excess ADIT (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)).

2. NOL Balance

With respect to the NOL balance, the Company increased its fiscal year 2018 balance estimated in D.P.U. 18-150 of $42,930,674 to the actual fiscal year 2018 balance of $53,034,825 after the IRS completed the audit on its federal income tax returns as of fiscal year 2018 (Exhs. NG-RRP-2, Sch. 11, at 4 (Rev. 4); DPU 8-17, Att.). Specifically, National Grid adjusted its NOL balance to recognize the tax differential (i.e., the corporate income tax rate decrease from 35 percent to 21 percent pursuant to the 2017 Tax Act) on the change of the NOL carryforward balance (Exh. DPU 8-14). Because the NOL carryforward can offset future taxable income and reduce future tax liability, the Company accounts for it by establishing a deferred tax asset (Exh. DPU 8-15; Tr. 8, at 1198-1199). According to National Grid, the remeasurement of this deferred tax asset pursuant to the 2017 Tax Act's reduction in federal corporate income tax rate constitutes "excess ADIT related to an NOL" (Exh. DPU 8-15). National Grid stated that it included the benefit of the NOL carryforward at the 35-percent tax rate in the income tax expense in base distribution rates prior to the 2017 Tax Act, and the 14-percent tax differential must be included in the income tax expense to avoid an IRS normalization violation (RR-DPU-38 & Att.).[146] National Grid states that the IRS normalization rule[147] requires the

[146] The Company explains that with the enactment of the 2017 Tax Act, the tax benefit that the Company expected to realize from its NOL carryforward was remeasured to the enacted tax rate of 21 percent (RR-DPU-38, at 2). Consequently, while the benefit of the NOL was passed on to customers in the years it was generated at 35 percent, the Company would realize the benefit of the NOL at only 21 percent (RR-DPU-38, at 2).

[147] Under IRS normalization rules, reserves for excess ADIT associated with protected property are reduced over the life of the associated property. 2017 Tax Act, § 1561(d) (1), (2). A violation of these normalization rules could have adverse tax

Company to fully offset this tax differential with the protected plant-related excess ADIT (Exhs. DPU 8-15; DPU 31-34; RR-DPU-38).

The Department finds that the recognition of the deferred tax asset related to the NOL carryforward must be derived by applying the effective income tax rate to the NOL carryforward, i.e., the deferred tax asset related to the NOL carryforward should reflect the available tax deduction in the future based on the future effective income tax rate. Consequently, the Department finds that the 14-percent tax differential reflects the reduction to the deferred tax asset associated with the NOL carryforward that is no longer available for income tax deduction resulting from 2017 Tax Act (Tr. 8, at 1200-1201). Thus, the Department is not persuaded that the 14-percent tax differential is a regulatory asset (RR-DPU-3, Att.; RR-DPU-38 & Att.).

Moreover, the Department had previously accepted the Company's proposal on the amortization of the "excess ADIT related to an NOL" balance over approximately eight years subject to the pending IRS clarification on normalization rules. D.P.U. 18-150, at 197-198. On August 14, 2020, the IRS issued Revenue Procedure 2020-39 providing guidance under 26 C.F.R. § 168 to clarify the normalization requirements following the corporate tax rate reduction provided in the 2017 Tax Act. The IRS noted that its guidance does not create an exception to how the overall pre-existing deferred tax normalization rules would apply. Revenue Procedure 2020-39, at 8-9. Rather, Revenue Procedure 2020-39 provides clarification of the amortization method of average rate assumption method for protected plant-related excess ADIT

consequences for the public utility, including potential tax penalties under the 2017 Tax Act, § 1561(d) (3), (4).

only. Revenue Procedure 2020-39, at 5-7. Regarding the NOL carryforward, the IRS determined:

> Compliance with normalization requires a determination of the source of an [NOL carryforward] so that rate base is not overstated in jurisdictions in which net deferred tax liabilities reduce rate base. While § 1.167(l)-1(h)(1)(iii) is the relevant general authority, there is not one single methodology provided for determination of the portion of an [NOL carryforward] that is attributable to depreciation. Section 1.167(l)-1(h)(1)(iii) instead informs taxpayers that the amount and time of the deferral of tax attributable to depreciation when there is an [NOL carryforward] should be taken into account in such "appropriate time and manner as is satisfactory to the district director." Regulating commissions have expertise in this area, and any reasonable method for determining the portion of the [NOL carryforward] attributable to depreciation should generally be respected provided such method does not clearly violate normalization requirements.

Revenue Procedure 2020-39, at 8.

Additionally, under the 2017 Tax Act, reserves for excess ADIT associated with protected property are reduced over the life of the associated property. 2017 Tax Act, § 1561(d)(1), (2). Moreover, IRS regulations require that a taxpayer "in order to use a normalization method of accounting with respect to any public utility property, […] in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation […] that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense […]." 26 C.F.R. § 168(i)(9)(A)(i). The IRS regulations also provide that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under 26 C.F.R. § 1.167(l) that is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. 26 C.F.R. § 1.167(l)-(h)(6)(i). If the allowable deduction to the income tax expense for ratemaking purposes is different under § 1.167 and § 168, a taxpayer must calculate an adjustment to the reserve to reflect the deferred taxes related to these differences. 26 C.F.R. § 168(i)(9)(A)(ii). Further, the regulations provide that, for the purpose of determining the maximum amount of the reserve to be excluded from rate base (or to be included as no-cost capital), if such determination is made by reference both to a historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period. 26 C.F.R. § 1.167(1)-1(h)(6)(ii). In this respect, the Department finds that the reserve related to the federal income tax asset eligible to offset the total ADIT and excess ADIT would not include the 14-percent tax differential that is no longer a deferred tax asset due to the 2017 Tax Act.

The Department has long relied on the return on rate base method and has directed that all companies use this method to determine income tax expenses for ratemaking purposes. D.P.U. 17-35-C at 132; D.P.U. 87-228, at 20; D.P.U. 1270/1414, at 45-46. Under the return on rate base method, the income tax expense for ratemaking purposes is derived from applying effective federal and state income tax rates to the grossed-up taxable income base, which is calculated from the return on rate base and reduced by interest expense and additional various adjustments. Agawam Springs Water Company, D.P.U. 13-163, at 58 (2014); D.P.U. 10-70-A at 4; D.P.U. 88-172, at 62; D.P.U. 88-135/151-A at 15; D.P.U. 87-59, at 53-54; Boston Gas

Company, D.P.U. 1100, at 78 (1982); Western Massachusetts Electric Company, D.P.U. 957, at 70-71 (1982); D.P.U. 906, at 64-65; Dedham Water Company, D.P.U. 205, at 33 (1981); New Bedford Gas and Edison Light Company, D.P.U. 20132, at 20 (1980). The various adjustments do not include deferred taxes associated with NOL because rates are set prospectively. D.P.U. 17795, at 9. As such, the deferred tax asset recognized for the NOL carryforward each year is not realized as an annual deduction in the income tax expense for ratemaking purposes. D.P.U. 15-155, at 523; D.P.U. 09-39, at 450. In addition, the rate base used for deriving the income tax expense is increased by the total deferred tax asset recognized for the NOL carryforward and reflects the available tax deduction in the future based on the future effective income tax rate pursuant to IRS regulations (Exh. NG-RRP-2, Sch. 11, Excel, tab P3- ADIT Summary (Rev. 4)). 26 C.F.R. § 168(i)(9); 26 C.F.R. § 1.167(l)-1. As such, the deferred tax asset recognized for the NOL carryforward increases rate base,[148] which results in the increase of the income tax expense for ratemaking purposes. Because the ADIT balance is a source of interest-free funds provided by ratepayers, it is an offset to a company's rate base. D.P.U. 87-59, at 63; D.P.U. 85-137, at 31; D.P.U. 1350, at 42-43; D.P.U. 18200, at 33-34. Accordingly, the Department finds that the full amount of the plant-related ADIT reduced by the total deferred tax asset related to NOL carryforward results in higher rate base and higher income tax expense. The total excess ADIT unreduced by the 14-percent tax differential of NOL carryforward represents the deferred taxes that have been collected through rates and are no longer owed to the

148 Because the deferred tax asset recognized for the NOL carryforward reduces the ADIT balance that is a deduction to rate base, the deferred tax asset recognized for the NOL carryforward therefore increases rate base.

IRS because of the tax rate decrease pursuant to the 2017 Tax Act. D.P.U. 18-15. Therefore, the Department finds that reducing the excess ADIT credit to rate base by the 14-percent tax differential is equivalent to twice requesting the same deferred tax asset related to the NOL carryforward.

Based on the foregoing reasons, the Department finds that the 14-percent tax differential that the Company accounts for as a deferred tax asset should not be collected through base distribution rates, and the Department declines to increase rate base by the remaining balance of the "excess ADIT related to an NOL" as of September 30, 2024. Further, the Department declines to accept the Company's updated NOL balance to offset the plant-related ADIT. Accordingly, the Department increases the Company's total excess ADIT balance by $24,200,116, which represents the sum of the remaining balance of $14,095,965 and the proposed increase of $10,104,151.[149, 150]

3. Other Excess ADIT

The Department has reviewed the Company's final excess ADIT balances as of the test year end for the protected plant-related, unprotected plant-related, unprotected non-plant-related, and NGSC-related and finds them to be reasonable (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)). The Company does not anticipate further changes to the unamortized excess ADIT balances or further clarifications of IRS normalization rules (Exh. DPU 8-16). Therefore, the Department

149 $42,930,674 – ($22,210,163 +$3,358,566 + $279,912 + $2,986,068) = $14,095,965 (Exhs. NG-RRP-2, Sch. 11, at 4, lines 5-6 (Rev. 4); DPU 8-17, Att.).

150 $53,034,825 - $42,930,674 = $10,104,151 (Exhs. NG-RRP-2, Sch. 11, at 4, lines 5-6 (Rev. 4); DPU 8-17, Att.).

accepts National Grid's final excess ADIT balances for the protected plant-related, unprotected plant-related, unprotected non-plant-related, and NGSC-related, and we allow the Company to roll into base distribution rates the remaining balance of excess ADIT.

In the Company's pending TACF filing, it included refunding the excess ADIT balance to ratepayers the amount amortized to September 30, 2024. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-01, Sch. DEG-16, at 4. Consistent with the requirements of the Company's current tariff M.D.P.U. No. 1410, Tax Credit Provision, the Department expects the Company to file in its next annual retail rate filing the final reconciliation of either an over- or under-refund of excess ADIT that coincides with the amount of the total refund as of September 30, 2024, and as provided in the cost-of-service schedules in the instant proceeding (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)). The Company shall true-up the total refund through its TACF as of September 30, 2024 with the total amortized amount of $36,256,400 (before tax gross up) as of September 30, 2024 presented on Exhibit NG-RRP-2, Schedule 11, at 4 (Rev. 4), and refund or charge the difference (after tax gross up) with interest based on customer deposit rate through the next annual retail rate filing (Exh. NG-RRP-2, Sch. 11, at 4, Lines 2, 6, 10, 15, 20, 24, 28, 33 (Rev. 4)). M.D.P.U. No. 1410.

Further, National Grid proposes to continue refunding excess ADIT according to the amortization periods approved in D.P.U. 18-150, which are an average service life of: (1) 39 years for protected plant-related excess ADIT; (2) 20.1 years for unprotected plant-related excess ADIT; (3) five years for unprotected non-plant related excess ADIT; and (4) 9.3 years for unprotected NGSC-related excess ADIT (Exhs. NG-RRP-1, at 88; DPU 8-18). D.P.U. 18-150, at 194-196. Because it has been five years since the approved amortization periods in the prior base distribution rate case, the amortization periods in the instant proceeding have been decreased by five years to reflect the beginning of the rate years between the last rate case and the instant proceeding (Exhs. NG-RRP-1, at 88; DPU 8-18). The Department previously recognized the amortization periods approved were subject to change after the fiscal year ending 2018 audit of National Grid's financial statements was completed and the Company determined the precise accounting method it must use to comply with the 2017 Tax Act. D.P.U. 18-150, at 192; D.P.U. 18-15-E at 12 n.15, 35. In this proceeding, National Grid provided its final balance of excess ADIT after the IRS audit concluded and, based on the analysis above regarding the anticipated clarifications on IRS normalization rules, the Department finds that the Company's proposal to continue the amortization periods approved in D.P.U. 18-150 is reasonable with the exception of the unprotected non-plant-related excess ADIT, as discussed below.

The Company proposes the following excess ADIT annual amortization amounts based on the approved amortization periods: (1) $5,812,917 for protected plant-related; (2) $3,241,912 for unprotected plant-related; (3) $513,100 for unprotected non-plant-related; and (4) $110,328 for unprotected NGSC-related. The sum of these amortizations equals a total proposed annual excess ADIT amortization of $9,678,258 (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)). The Company expects that the amortization of unprotected non-plant-related excess ADIT will conclude by September 30, 2024 (Exh. DPU 8-16 n.2). National Grid also reports that its unprotected non-plant-related excess ADIT balance as of the test year end is $7,147,651, and as of September 30, 2024, is $4,582,148 (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)). Although National Grid proposes to continue the amortization period for the unprotected non-plant-related excess ADIT as approved in D.P.U. 18-150, which results in an amortization period of zero years in the instant proceeding, the Company's calculations show it used an amortization period of five years (Exh. DPU 8-17 & Att.; Tr. 7, at 997-998; RR-DPU-27 & Att.). In consideration of the remaining excess ADIT balance, the Department finds it appropriate to amortize the updated unprotected non-plant-related excess ADIT over five years. Therefore, we accept the Company's proposal resulting in the annual amortization amount of $513,100 (Exh. NG-RRP-2, Sch. 11, at 4 (Rev. 4)). Additionally, the Department accepts the Company's proposed annual excess ADIT amortization amounts for protected plant-related, unprotected plant-related, and unprotected NGSC-related.

VIII. FEDERAL AND STATE INCOME TAXES

A. Introduction

National Grid proposes a total federal and state income tax expense in the amount of $53,421,102 (Exh. NG-RRP-2, Sch. 10, at 1 (Rev. 4)). The Company's income tax calculations includes a total flow-through and other tax-only adjustment of negative $9,087,442 comprising: (1) a flow-through of negative $2,312,831 for the equity component of AFUDC and associated book depreciation; (2) negative $1,391,768 for its research and development tax credit proposal amortization; (3) negative $2,595,512 for its investment tax credits amortization; (4) $272,529 associated with the tax basis related to its investment tax credits; (5) $904,532 for the deficient state ADIT amortization; and (6) negative $3,964,393 for the excess ADIT refund amortization associated with its proposal to transfer into base distribution rates the 2017 TACF balance, as discussed above (Exhs. NG-RRP-1, at 85-88; NG-RRP-2, Sch. 10, at 2 (Rev. 4)).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that annually over the last five years the Company was allocated an average of $3,670,000 in income tax loss from its parent company, which she claims is measurable and significant (Attorney General Brief at 117-118, citing Exh. AG 1-2, Atts. 26, at 39; 28, at 36; 41, at 37; Attorney General Reply Brief at 28-29). The Attorney General contends that the Department historically has recognized this income tax benefit as a reduction to a company's revenue requirement (Attorney General Brief at 117-118, citing Western Massachusetts Electric Company, D.P.U. 89-255, at 47 (1990); Attorney General Reply Brief at 29). Therefore, the Attorney General asserts that the Department should reduce the Company's cost of service by $1,379,532[151] to reflect the allocated share of its parent company's income tax loss (Attorney General Brief at 117-118; Attorney General Reply Brief at 29).

2. Company

National Grid summarizes its income tax calculations on brief (Company Brief at 271-274, citing Exhs. NG-RRP-1, at 85-86; NG-RRP-2 Sch. 10 (Rev. 3); DPU 31-16; DPU 31-18; DPU 31-19; DPU 31-20). National Grid argues that there is no basis to reduce its cost of service by $1,379,532, as the Attorney General has not provided sufficient analysis or other information adequately supporting her recommendation (Company Brief at 368; Company Reply Brief at 51). According to the Company, the Attorney General's argument is inconsistent

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151 The Attorney General derives her adjustment by first grossing up the average income tax loss over the previous five years of $3,670,000, and then multiplying it by a combined federal and state income tax rate of 27.32 percent, thus $3,670,000 ÷ (1 – 0.2732) × 0.2732 = $1,379,532 (Attorney General Reply Brief at 29).

with Department policy and precedent to calculate taxes on a stand-alone basis for utilities, including those utilities that are part of a corporate system (Company Reply Brief at 51, citing D.P.U. 93-60; D.P.U. 89-194/195, at 66; D.P.U. 89-194-C/195-A at 15-17).

C. Analysis and Findings

The Department has long relied on the return on rate base method to determine income taxes for ratemaking purposes. D.P.U. 17-35-C at 132; D.P.U. 87-228, at 20; D.P.U. 1270/1414, at 45-46. Under this approach, the return on rate base is first determined, and then it is reduced by interest expense. D.P.U. 1100, at 78; D.P.U. 957, at 70-71; D.P.U. 906, at 64-65; D.P.U. 20132, at 20. Various additions and deductions are then made as appropriate to derive a taxable income base. D.P.U. 10-70-A at 4; D.P.U. 88-135/151-A at 15; D.P.U. 87-59, at 53-54; D.P.U. 205, at 33. Generally, the Department has followed the practice of matching recovery of tax benefits and losses to the recovery of the underlying expense with which the tax effects are associated. D.P.U. 85-270-A at 132. The taxable income base is then grossed up for federal and state taxes to produce the pre-tax income level (or taxable income level), to which state and federal taxes are then applied. D.P.U. 13-163, at 58; D.P.U. 88-172, at 62. Because the return on rate base method allows various adjustments to be readily identified and made, the Department has directed that all companies use this method for the purpose of computing income tax expense. D.P.U. 1270/1414, at 46.

National Grid's income tax proposal follows the return on rate base method and includes various adjustments to the taxable income base and the calculated income tax expense (Exhs. NG-RRP-2, Sch. 10 (Rev. 4); NG-RRP-2, Sch. 7, at 11 (Rev. 4)). The Department has reviewed the Company's proposed income tax expense calculation and makes the following directives, discussed below and in in the preceding section relative to the Company's excess ADIT balances.

The Department first addresses the Company's proposed $2,312,831 reduction to income tax expense to flow through the equity portion of AFUDC income (Exhs. NG-RRP-1, at 83; NG-RRP-2, Sch. 10, at 2 (Rev. 4); DPU 8-9). AFUDC is an accounting and ratemaking convention that allows companies to recover the costs of financing a construction project by capitalizing the carrying charges associated with financing the project during construction and including those costs as a part of plant in service in rate base. Fitchburg Gas and Electric Light Company, D.P.U. 19084, at 8 (1977); D.P.U. 18515, at 53. AFUDC consists of a debt component (i.e., interest on borrowed funds) and an equity component (e.g., retained earnings). D.P.U. 84-135, at 12. Consistent with FERC and Department accounting requirements, National Grid books the debt component of AFUDC as a non-cash offset to interest expense and books the equity component of AFUDC as non-cash income booked to Account 419 (Exhs. AG 1-2, Att. 28, at 28-29, Att. 31, at 19-21; DPU 31-16, Att. 1). Equity AFUDC is capitalized as part of construction work in progress, and subsequently depreciated over the life of the associated asset through depreciation expense (Exh. DPU 8-9).

Because the AFUDC equity income and the associated book depreciation expense are excluded from taxable income, a temporary timing difference is created, thus giving rise to deferred income taxes (Exh. DPU 8-9). National Grid records the cumulative tax effects of equity AFUDC as a deferred asset representing the future recovery of these deferred taxes, for which the tax benefits had been flowed through to customers in previous years (Exh. NG-RRP-1, at 83). According to the Company, the recording of a regulatory asset is a required offsetting entry to the equity AFUDC-associated deferred tax liability born from excluding the depreciation expense from income in accordance with FERC guidance on accounting for income taxes in FERC Docket No. AI93-5-000 (Exh. DPU 8-9 & Att.; Tr. 8, at 1194).[152] National Grid uses normalization accounting except for equity AFUDC, for which the Company uses the flow through method to amortize the associated regulatory asset (Exhs. DPU 8-9; DPU 31-18; DPU 31-20; AG 1-88; Tr. 2, at 296-297).[153]

The Department finds that the Company's flow through treatment of the "cumulative tax effect of the equity AFUDC" is distinct from the treatment of equity AFUDC. Specifically, the Company proposed the flow through treatment to the contra account of the equity AFUDC recording, where each accounting journal entry consists of credit and debit accounts, and in this instance the regulatory asset, i.e., the cumulative tax effect, is the accounting offsetting entry for the equity AFUDC (Exhs. DPU 8-9, Att. at 5; DPU 31-16, Att. 1). As such, each accounting journal entry presents two sides of one business transaction that does not warrant two separate ratemaking treatments. The Department requires that a company show equity AFUDC on its books as a reserve for the tax savings that is incurred through AFUDC recognition.

152 According to the Company, FERC accounting procedures are an industry standard that provides a guide to utility operations, and that it is standard practice for regulatory commissions to follow FERC accounting procedures (Tr. 8, at 1195-1196).

153 FERC's regulations have required jurisdictional companies to determine the income tax allowance included in jurisdictional rate levels on a fully normalized basis since 1981 (Exh. DPU 8-9, Att. at 2). National Grid stated that its use of the flow through method for equity AFUDC is not a violation of the normalization rules established pursuant to 18 C.F.R. § 35.24 and 26 C.F.R. § 1.167(l) because normalization accounting is not required for these types of book-to-tax temporary differences (Exhs. DPU 8-9, Att. at 2-3; DPU 31-18; Tr. 2, at 296-297).

D.P.U. 85-270-A at 132, Table 3B. When the plant associated with that AFUDC is placed in service, a company incurs taxes on the AFUDC, reduced by the portion of the tax savings reserve accumulated during construction of the plant. D.P.U. 19084, at 7-9. Then, over the useful life of the plant that gave rise to the tax savings, the company would pass back a tax reduction equal to the tax savings divided by the useful life of the plant. D.P.U. 19084, at 7-9. Under this approach, the interest expense benefit is shifted from current ratepayers to future ratepayers, who would be repaying the interest component accumulated during construction through depreciation expense, thus creating a matching of the timing of the cost with the savings. D.P.U. 19991, at 33.

Here, the Company's description of its accounting process demonstrates that its accounting treatment pertains to the regulatory asset it established when it capitalized the AFUDC equity income, rather than on the equity AFUDC booked to a reserve account (Exhs. DPU 8-9; DPU 31-16, Att. 1; DPU 31-17). That is, the Company's proposed method shows a flow through of the tax effect of equity AFUDC to establish a regulatory asset, with the offsetting accounting entry to equity AFUDC at the time of capitalization to construction work in progress to be passed to customers and the tax charge flowed through depreciation expense (Exhs. DPU 31-16, Att. 1; DPU 31-17). Therefore, the Company's proposed flow-through method is contrary to the Department's ratemaking treatment for equity AFUDC (Exhs. DPU 31-16 & Atts.; DPU 31-17). D.P.U. 19084, at 8-9. The Department has reviewed the Company's itemized ADIT and found that the equity AFUDC is properly accounted for as a deduction to rate base, which validates the reserve accumulated during construction, and complies with the Department's ratemaking treatment for equity AFUDC (Exhs. DPU 31-1, Att.;

DPU 31-20). Further, the Department's ratemaking practice is to normalize the tax benefits associated with AFUDC over the life of the associated property. D.P.U. 19084, at 8-9. While the IRS permits utilities to deduct AFUDC interest expense as it is incurred, the Department's income tax calculations for ratemaking purposes do not include such a practice. D.P.U. 19084, at 8-9. Based on the foregoing, the Department disallows the proposed flow-through adjustment of equity AFUDC of $2,312,831.

Turning next to the total income tax expense adjustment, after National Grid grosses up its adjusted income tax base and calculates the resulting income tax expense, it then reduces its calculated income tax expense by $9,087,442 representing the total proposed flow-through and other tax adjustments, thus creating a proposed credit to the proposed income tax expense (Exhs. NG-RRP-2, Sch. 10, at 1 (Rev. 4); NG-RRP-7, at 11 (Rev. 4)). The Company states that the proposed flow-through and other tax adjustments represent the amortizations of the proposed regulatory asset/liability pre-gross up (Exhs. NG-RRP-2, Sch. 11, at 4-5 (Rev. 4); DPU 8-10, Att.; DPU 8-11, Att.; DPU 8-18; DPU 31-26). The Department finds that the proposed reduction to the calculated income tax expense is underestimated by the gross-up amount. Based on the analysis and findings above, and in the preceding section addressing ADIT, the Company's total flow-through and other tax adjustments is decreased by $2,312,831 related to equity AFUDC, and increased by $5,713,865 related to excess ADIT, resulting in a flow-though and other tax adjustments amount of negative $12,488,476 before gross up.[154] Thus, the Department decreases

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154 ($9,087,442) + $2,312,831 + ($5,713,865) = ($12,488,476)

the Company's income tax expense by $4,694,348 for the gross-up amount.[155] This reduction represents the total gross-up amount of the approved total flow-though items and other tax adjustments, including the net excess deferred tax. Therefore, the final approved flow-though and other tax adjustments is $17,182,824. Accordingly, the Department reduces the Company's proposed income tax expense by $8,095,382.[156]

The Attorney General recommends that the Department reduce the Company's cost of service by $1,379,532 to reflect the allocated share of its parent company's income tax loss (Attorney General Brief at 117-118; Attorney General Reply Brief at 29). With respect to the income tax expense adjustment associated with the parent company tax loss allocation raised by the Attorney General, the Department previously addressed whether to reflect a system tax loss in the rates of a regulated utility. D.P.U. 89-194/195, at 66; D.P.U. 89-255, at 47 n.5. The Department calculates taxes on a "stand-alone" basis for utilities, including those that are part of a system, and generally, the Department has followed the practice of matching recovery of tax benefits and losses to the recovery of the underlying expense with which the tax effects are associated. D.P.U. 85-270-A at 132, Table 3B; D.P.U. 89-255, at 47 n.5; D.P.U. 89-194/195, at 66. While the Department's income tax computation method incorporates consolidated tax savings associated with tax losses of a company's unregulated affiliates, the Department does not recognize consolidated tax savings arising from tax losses of regulated affiliates because

155 ($12,488,476) x (1 ÷ (1-(21% x (1-8%) + 8%))-1)= ($4,694,348)

156 Negative $17,182,824 minus negative $9,087,442 equals $8,095,382. The adjustment for net excess deferred tax is listed separately in the Department's income tax schedule, Schedule 8 below.

reducing tax expense for losses incurred by individual affiliates would perpetuate the cycle of loss-generating subsidiaries. Dedham Water Company, D.P.U. 1217, at 22 (1983). Cf. D.P.U. 243, at 27-29; Lowell Gas Company, D.P.U. 19666, at 16-17 (1979); Massachusetts Electric Company, D.P.U. 19376, at 58-60 (1978); Boston Gas Company. D.P.U. 16102, at 33-38 (1970) (distinction between regulated and unregulated affiliates regarding consolidated tax losses). The record evidence shows that the parent company charges are not allocated to the Company but are instead maintained at the parent level (Exh. AG 28-30 & Atts.). Furthermore, while the Attorney General identifies tax losses from National Grid's parent, these allocations are associated with non-cash financing and investing activities, and there is insufficient information to determine whether these tax losses are associated with regulated versus unregulated operations (Exh. AG 1-2, Atts. 26, at 39; 28, at 36; 41, at 37). Therefore, the Department declines to adjust the Company's income tax expense to reflect the parent company income tax loss allocation.

The Department has reviewed the remaining components of National Grid's proposed income tax expense calculation and, subject to our findings above and in the preceding section with respect to excess ADIT, we find the Company's computation of income tax expense components to be reasonable. Therefore, the Department relies on these components in determining the Company's income tax expense as calculated on Department Schedule 8.

IX. VEGETATION MANAGEMENT PROGRAM

A. Introduction

National Grid states that its vegetation management program is intended to maintain or improve safety and reliability by providing for the reduction of vegetation-related safety hazards, service interruptions, and disturbances to a level consistent with a high degree of customer satisfaction and at a minimal cost to customers, stakeholders, and the environment (Exh. NG-VMP-1, at 5). The Company's current vegetation management program consists of five sub-programs: (1) maintenance pruning; (2) core crews; (3) sub-transmission work; (4) enhanced hazard tree mitigation; and (5) an EVM Pilot (Exh. NG-VMP-1, at 5).[157] Each of these vegetation management sub-programs are described below.

National Grid's maintenance pruning program is designed to minimize the risk to the public of falling trees and wildfires as well as minimize the risk of worker electrocutions (Exh. NG-VMP-1, at 5). Further, the Company states that consistent cycle pruning helps maintain service reliability by avoiding potential interruptions from phase-to-phase tree contact (Exh. NG-VMP-1, at 5). The Company's pruning specifications provide for certain minimum distances between all vegetation and power lines (Exh. NG-VMP-1, at 6).[158] The Company reports that in fiscal year 2022, in an effort to better meet applicable SAIDI and SAIFI metrics and to help track the impacts from climate change over time and adjust pruning work accordingly, MECo moved away from a five-year fixed time-based cycle and implemented a Vegetation Management Optimization ("VMO") program (Exhs. NG-VMP-1, at 6, 9-11;

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157 The first four vegetation management sub-programs are recovered through base distribution rates, while the fifth sub-program (EVM Pilot) is recovered through the Vegetation Management Pilot Provision (M.D.P.U. No. 1503) through two rate class-specific reconciliation factors.

158 Specifically, the Company provides its minimum pruning clearance distances as: (1) ten feet below the conductor and removal of any species of vegetation capable of reaching the conductor; (2) six feet to the side of the conductor; and (3) ten feet above the conductor in maintained yard areas in residential areas or 15 feet above the conductor in unmaintained properties in rural areas (Exh. NG-VMP-1, at 6).

AG 7-12). Under the VMO program, the Company uses satellite imagery and real-time data analytics to determine the optimal time for pruning each circuit, rather than relying on a fixed pruning cycle (Exhs. NG-VMP-1, at 6; AG 7-12). Under the VMO program, pruning cycles will vary from four to seven years, based on actual conditions on each circuit (Exhs. NG-VMP-1, at 7; AG 7-12). The Company maintains a four-year pruning cycle for Nantucket Electric because the service area is smaller, vegetation conditions are more uniform, and circuit length and conditions on Nantucket have not yet necessitated a change (Exhs. NG-VMP-1, at 7, 12; DPU 42-2).

National Grid's core crews program consists of interim or spot trimming on small sections of the Company's circuits where vegetation is growing very close to, or in some cases through, the power lines (Exhs. NG-VMP-1, at 7; DPU 42-3). The program also includes customer requests and emergency response pruning (Exhs. NG-VMP-1, at 7; DPU 42-3). Core crew activities are not planned ahead of time, and their purpose is generally addressing vegetation conditions related to power interruptions or to meet minimum clearance specifications (Exh. DPU 42-3).

National Grid's sub-transmission work consists of pruning trees along the sub-transmission lines, which can be either on the roadside or within the Company's rights of way (Exh. NG-VMP-1, at 7). In addition to pruning in these areas, the Company maintains the vegetation growth along the floor or underneath the conductors and within the rights of way to ensure the vegetation remains under control until the sub-transmission line is pruned again (Exh. NG-VMP-1, at 7). National Grid states that sub-transmission circuits are typically maintained on a five-year pruning cycle, but the Company may adjust that frequency for some circuits to balance mileage in a district from one fiscal year to the next or if a circuit needs more immediate attention (Exh. DPU 42-7).

National Grid's enhanced hazard tree mitigation program was implemented in 2008 and is designed to identify hazard trees that are diseased, dying, or dead along the Company's circuits and remove those that are an imminent threat to power lines and public safety (Exh. NG-VMP-1, at 7-8). The Company states that this program focuses on improving reliability on selected circuits, which are identified based on three years of reliability performance data; the number of miles of three-phase bare overhead conductor that are most susceptible to tree-related interruptions; tree stocking density; and customer count on the circuit (Exh. NG-VMP-1, at 8).

In 2018, National Grid's EVM Pilot was approved for a four-year term, to end on March 31, 2023. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 17-92, at 6, 8 (2018).[159] The EVM Pilot targets the Company's worst-performing three-phase circuits that demonstrate a history of tree-related power outages and serve critical infrastructure (Exh. NG-VMP-1, at 8, 17). The scope of work was intended to be based on a consideration of tree-related field conditions, customer counts, miles of each circuit, the presence of scenic roads or other vegetation management restrictions, and the critical infrastructure needs for affected municipalities and the locations of critical facilities (Exh. NG-VMP-1, at 17, citing D.P.U. 17-92, at 5-6, 22-23; D.P.U. 15-155, at 328-329). In 2021, the Department modified the

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159 National Grid submitted a proposal for the EVM Pilot in response to Department directives issued in the Company's 2016 base distribution rate proceeding. D.P.U. 15-155, at 328-329.

EVM Pilot and the Company's scope of work to: (1) identify sections of targeted three-phase circuit portions where protective devices, such as fuses and pole-top reclosers, have activated most frequently from tree-related outages; (2) perform work on these sections rather than the entirety of targeted circuits; (3) focus work on pruning and removal of only hazard trees that are farther from the wires, rather than removal of all trees, within the expanded clearance distance; and (4) exclude sub-transmission circuits from pilot work for the final two years (Exh. NG-VMP-1, at 8, 17-18). See also Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 20-140-A at 9, 21 (2021); D.P.U. 20-140, at 4-6 (2021).[160] Subsequently, the Department extended the term of the EVM Pilot to September 30, 2024. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-171-A at 7, 10 (2023). The Company assesses the reliability performance of the EVM Pilot work by using a three-year baseline to compare the monthly average number of tree-related events, customers interrupted, and customer minutes interrupted for each feeder in the three years prior to the EVM Pilot work on that circuit with the same categories of tree-related outage data after the work is completed (Exh. NG-VMP-1, at 20).

The Company's vegetation management program work is performed by third-party contractors retained through competitive bidding processes (Exh. NG-VMP-1, at 9, 13). The Company recovers costs associated with maintenance pruning, core crews, sub-transmission work, and enhanced hazard tree mitigation through base distribution rates, with the exception of

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160 The Department also approved the Company's expanded scope of consultants' condition assessments of targeted circuits prior to work being performed. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 19-144-A at 13-14 (2020).

VMO technology, which is deemed an IT expense (Exh. NG-VMP-1, at 12-13).[161] The Company recovers incremental O&M expenses for the EVM Pilot through the Vegetation Management Pilot Provision tariff which includes two rate class-specific annual factors: (1) the Vegetation Management Pilot Factor ("VMF") for allowed O&M expenses for the prior calendar year; and (2) the Vegetation Management Reconciliation Factor ("VMRF") for the difference between the allowed O&M expenses and the billed revenue from the VMF (Exh. NG-VMP-1, at 18). M.D.P.U. No. 1503; D.P.U. 17-92, at 45-47.

B. Company Proposal

National Grid proposes to make two changes to its vegetation management program. First, the Company proposes to increase the amount of vegetation management costs recovered through base distribution rates (Exhs. NG-VMP-1, at 15-16; NG-RRP-1, at 109). During the test year, the Company incurred a total of $39,558,637 in O&M costs recoverable through base distribution rates and associated with maintenance pruning, core crews, sub-transmission work, and enhanced hazard tree mitigation (Exhs. NG-VMP-1, at 12; NG-RRP-2, Sch. 42, at 1 (Rev. 4); DPU 10-3; AG 7-26 (Supp.)). This amount excludes the costs incurred for the EVM Pilot because, as noted above, EVM Pilot costs are recovered through a separate reconciling mechanism (Exh. NG-VMP-1, at 18). National Grid seeks to increase the test-year level of expense by $4,566,543 to $44,125,180, based on an increase in contractor bids for work to be performed during the rate year, as compared to actual work performed during the test year (Exhs. NG-VMP-1, at 15; NG-RRP-1, at 109; NG-VMP-2; NG-RRP-2, Sch. 42, at 2 (Rev. 4);

161 The Company also recovers (through base distribution rates) traffic control costs associated with maintenance activities (Exh. NG-VMP-1, at 13).

DPU 10-4; DPU 10-5 (Supp. 2); DPU 10-8 (Supp. 2); AG 7-26 (Supp.); Tr. 8, at 1058-1059; RR-DPU-32). Any future expense increases are proposed to be funded through the revenue adjustments proposed in the PBR mechanism (Exh. NG-VMP-1, at 16).

Second, National Grid proposes to continue the EVM Pilot for five years to coincide with the proposed five-year rate plan, to expand the scope of the EVM Pilot, and to continue to recover the costs of the pilot outside of base distribution rates through the VMF and the VMRF (Exhs. NG-VMP-1, at 19, 21-22; NG-RRP-1, at 109). With respect to scope, National Grid proposes to continue to target the worst performing feeders and circuits that experience a large number of tree-related interruptions, but the Company proposes to focus on areas within each circuit that serve large numbers of customers, not just those serving critical infrastructure (Exh. NG-VMP-1, at 19). The Company states that the current critical infrastructure limitation may prevent some customers from experiencing the reliability benefits of the EVM Pilot (Exh. NG-VMP-1, at 19). The Company notes that of the 1,169 distribution circuits in Massachusetts, approximately 180 circuits do not serve critical infrastructure (Exh. NG-VMP-1, at 19). Further, the Company estimates that it will be able to perform EVM Pilot work on an additional 27 miles of distribution circuits and remove approximately 1,000 more hazard trees per year (Exh. NG-VMP-1, at 23). By fiscal year 2029, the Company estimates it will complete approximately 240 miles of EVM Pilot work and remove 8,000 hazard trees (Exh. NG-VMP-1, at 23).

C. Positions of the Parties

The Company maintains that its vegetation management costs remained relatively stable until 2019 when the average cost-per-mile of its third-party contractors increased by 16 percent

(Company Brief at 523). According to National Grid, these cost increases have forced the Company to reduce the number of miles it is able to prune to below the fiscal year 2016 and fiscal year 2018 levels (Company Brief at 523, citing Exh. NG-VMP-1, at 14). The Company asserts that continuing the vegetation management program with adequate funding is necessary as it serves as the first line of defense to prevent power outages and increase system resiliency during major storm events and other periods involving wind (Company Brief at 524).

National Grid also argues that it is necessary to continue and expand the EVM Pilot as part of its suite of vegetation management programs to improve resiliency and reliability in the Company's service areas (Company Brief at 529). The Company contends that, given the limited operational time of the EVM Pilot, and changes to the program during this time, it is appropriate to continue this program for another five years, with costs continuing to be collected through the established reconciling mechanism (Company Brief at 530). The Company claims that moving the EVM Pilot into base distribution rates without the annual filing and reconciliation would eliminate the annual review by the Department related to the EVM Pilot, including the pilot's ongoing results (Company Brief at 530). National Grid asserts that, if the EVM Pilot is allowed to continue outside of base distribution rates for another five years to develop additional data, the Company then would be amenable to moving the EVM Pilot into base distribution rates (Company Brief at 530). No other party commented on the Company's vegetation management program on brief.

D. Analysis and Findings

1. Vegetation Management Expense in Base Distribution Rates

In prior National Grid base distribution rate cases, the Department did not separate out a specific level of vegetation management expense to be recovered through the Company's cost of service. Rather, the Company included vegetation management costs in its cost of service through contractor expense (Exh. AG 7-9). In the instant case, the Company presents vegetation management costs as a separate line item in its cost of service and reports incurring $39,558,637 in such costs in the test year (Exhs. NG-VMP-1, at 12; NG-RRP-2, Sch. 42, at 1 (Rev. 4); DPU 10-3; AG 7-26 (Supp.)). The Company proposes to increase the test-year level of expense by $4,566,543 to $44,125,180 (Exhs. NG-VMP-1, at 15; NG-RRP-1, at 109; NG-VMP-2; NG-RRP-2, Sch. 42, at 2 (Rev. 4); DPU 10-4; DPU 10-5 (Supp. 2); DPU 10-8 (Supp. 2); AG 7-26 (Supp.); Tr. 8, at 1058-1059; RR-DPU-32). The Company bases its proposed vegetation management expense adjustment on the difference between actual test-year contractor costs and the finalized contractor bid awards for anticipated rate-year vegetation management work (Exhs. DPU 10-5 (Supp. 2); AG 7-26 (Supp.); Tr. 8, at 1055; RR-DPU-32).

It is a well-established Department precedent that base distribution rates are based on a historical test year, adjusted for known and measurable changes. D.P.U. 1580, at 13-17, 19; Massachusetts Electric Company, D.P.U. 136, at 3-5 (1980); D.P.U. 18204, at 4-5; New England Telephone & Telegraph Company, D.P.U. 18210, at 2-3 (1975); see also Mass Electric, 383 Mass. 675, 680. In this instance, the Department is satisfied that National Grid has demonstrated a known and measurable change to the Company's test-year level of vegetation management expense (Exhs. NG-VMP-1, at 15; NG-RRP-1, at 109; NG-VMP-2; NG-RRP-2, Sch. 42, at 1

(Rev. 4); DPU 10-4; DPU 10-5 (Supp. 2); DPU 10-8 (Supp. 2); AG 7-26 (Supp.); Tr. 8, at 1058-1059; RR-DPU-32). Accordingly, the Department allows the $39,558,637 in such costs for the test year and approves the Company's proposed increase to its cost of service of $4,566,543 over the test-year level for a total of $44,125,180.

2. EVM Pilot

The Department has recognized the significant financial burden that ratepayers have borne due to high storm restoration costs and, further, that the lack of proper pre-storm preparation may have adverse effects on that company's ratepayers. D.P.U. 22-22, at 272, 296; D.P.U. 18-150, at 414-415; D.P.U. 13-90, at 19; D.P.U. 11-01/D.P.U. 11-02, at 70-71. As a result, the Department views storm resiliency programs 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 to the benefit of ratepayers. D.P.U. 22-22, at 296; D.P.U. 17-05, at 578-579; D.P.U. 15-155, at 328; D.P.U. 13-90, at 19. In consideration of these factors, the Department directed National Grid to submit a pilot proposal for the Department's consideration. D.P.U. 15-155, at 328-329.

The Company's current EVM Pilot was intended to last only four years. D.P.U. 17-92, at 6, 8. As noted above, the Department extended the term to September 30, 2024. D.P.U. 22-171-A at 7, 10. In doing so, the Department recognized that the Company intended to file in the instant base distribution rate proceeding a proposal to make the program permanent. D.P.U. 22-171-A at 6, 8.[162] The Department also noted that an extension of the EVM Pilot to

162 The Company's stated intention was clear in its direct testimony:

September 30, 2024 would ensure a larger baseline of data upon which the Department and intervenors in the instant base distribution rate proceeding will be able to better evaluate the Company's anticipated proposal to make the pilot a permanent resiliency program.

D.P.U. 22-171-A at 8. Contrary to National Grid's stated intention in D.P.U. 22-171, the Company now seeks to continue the pilot program for another five years and recover the costs through the VMF and VMRF (Exhs. NG-VMP-1, at 19, 21-22; NG-RRP-1, at 109). The Department recognizes that the EVM Pilot has worked to strengthen National Grid's distribution system and reduce tree-related outages, especially during major weather events, which in turn has provided reliability benefits for customers and helped the Company meet its SQ reliability targets (Exhs. NG-VMP-1, at 20-21; DPU 10-11; DPU 27-15; DPU 42-25 & Att.; DPU 42-26 & Att.; RR-DPU-34; RR-DPU-35). As such, the Department acknowledges the importance of allowing the work performed under the EVM Pilot to continue. The Department finds that it is appropriate for National Grid to incorporate the enhanced circuit-related work as a permanent component of the Company's overall vegetation management program.

> An extension of the EVM Pilot until September 30, 2024 is necessary for the Company to recover the ongoing costs of the EVM Pilot until new base distribution rates reflecting the recovery of the cost associated with these activities go into effect and provide a continuation of cost information upon which to determine and support a representative level of EVM Pilot costs that the Company would propose to continue to be recovered in base distribution rates beginning October 1, 2024. If the term of the EVM Pilot is not extended, any EVM Pilot spending after March 31, 2023 will not be eligible for recovery, which may jeopardize the continuation of EVM Pilot work.
>
> D.P.U. 22-171, Exh. NG-1, at 3-4 (Supp.).

The Department also finds that it is reasonable and appropriate to transfer recovery of the costs associated with the enhanced circuit-related work to base distribution rates. The record shows that EVM Pilot costs were relatively stable from fiscal year 2020 through fiscal year 2023 (Exhs. AG 7-11, Att.; AG 7-14). Further, between 2020 through 2023, the average annual under-collection of EVM Pilot actual expenditures to those covered in the cost of service is approximately $98,750 (or 1.4 percent), a relatively modest deviation (see Exhs. AG 7-11; AG 7-16).[163] Additionally, including a representative level of enhanced circuit-related costs in base distribution rates will incentivize National Grid to employ greater cost-control measures and will remove the administrative burden of the Company submitting, and the Department and intervenors reviewing, annual reconciling filings.

With respect to setting the representative level of expense in base distribution rates, during the proceeding the Company estimated that enhanced circuit-related work would increase $1.5 million per year from the current annual budget of $7.0 million to $14.5 million by fiscal year 2029, for an annual average cost of $11.5 million (Exh. DPU 27-16; RR-DPU-33 & Att.).[164] The Company calculated these estimates by evaluating the reliability impact of the EVM Pilot and estimating the level of expense that would be necessary to help exceed SAIFI and SAIDI targets in the final step-change in the SQ glide path (Exh. DPU 27-16). National Grid also noted

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163 To derive the average annual EVM Pilot under-collection, the Department divided the total $395,000 under-collected amount of budget to actuals over the four-year period from 2020 through 2023 (see Exhs. AG 7-11; AG 7-16).

164 Specifically, the Company estimated it would spend $8.5 million in fiscal year 2025; $10.0 million in fiscal year 2026; $11.5 million in fiscal year 2027; $13.0 million in fiscal year 2028; and $14.5 million in fiscal year 2029, for a total of $57.5 million over five years, or an average of $11.5 million annually (RR-DPU-33, Att.).

that by establishing its estimated fixed amount of $11.5 million in base distribution rates, the Company anticipates that it would over-recover costs in the early years of its proposed five-year rate plan and under-recover in the later years of the plan (Exh. DPU 27-16; RR-DPU-33 & Att.).

It is well-established Department precedent that base distribution rates are based on a historical test year, adjusted for known and measurable changes. D.P.U. 1580, at 13-17, 19; D.P.U. 136, at 3-5; D.P.U. 18204, at 4-5; D.P.U. 18210, at 2-3; see also Mass Electric, 383 Mass. 675, 680. The Company's test-year level of EVM Pilot expense was $7,031,709 (Exhs. DPU 10-7; AG 7-11, Att.; AG 7-16). While it stands to reason these costs will increase over the next five years, the Company's projections and estimates do not represent a known and measurable change to the test-year level of expense. D.T.E. 98-51, at 62, citing D.P.U. 92-210, at 83; Dedham Water Company, D.P.U. 849, at 32-34 (1982). As such, the Department allows the Company to recover $7,031,709 annually in base distribution rates for enhanced circuit-related costs. This level of expense will be subject to the annual PBR-O adjustment discussed earlier in this Order, which will provide the Company additional annual revenues to meet its work requirements.

On this last point, the Department expects that the Company will continue to perform necessary enhanced circuit-related work to facilitate a safe and reliable electric distribution system. In targeting the worst performing feeders and circuits that experience a large number of tree-related interruptions, we encourage National Grid to focus not just on circuits serving on critical infrastructure, but also on areas within each circuit that serve large numbers of customers, as the Company proposed in its initial filing (Exh. NG-VMP-1, at 19). The Department also encourages National Grid to work collaboratively with other EDCs in Massachusetts to create a more comprehensive approach to address overall forest health. Effective vegetation management programs are vital in maintaining a safe and reliable electric grid and the importance of maintaining forest health (such as retaining the ecological functions of trees and vegetation), in turn, is vital to the local environment. Collaboration between the EDCs and the sharing of vegetation management best practices can both reduce the risk to company infrastructure and maintain healthy forests.

Finally, we recognize that the current EVM Pilot reconciling mechanism, the Vegetation Management Pilot Provision tariff, will need to stay in place for a period of time to allow for the recovery of prudently incurred EVM Pilot costs through September 30, 2024. Thus, National Grid shall maintain the tariff for this limited purpose until such time that the Company has completed rate treatment related to any over- or under-recoveries remaining in the mechanism as of September 30, 2024. In any filing seeking recovery through the tariff, the Company shall provide all relevant information and documentation, consistent with prior Department directives. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 19-144-A at 24-29, 32-38 (2020); D.P.U. 17-92, at 42, 46-47, 55-56. Thereafter, the Vegetation Management Pilot Provision tariff shall terminate. The Company shall revise its current tariff accordingly as part of its compliance filing in this proceeding.

X. STORM COST RECOVERY MECHANISM

A. Introduction

The Department first approved a storm fund cost recovery mechanism for the Company pursuant to a settlement in D.T.E. 99-47. Since that time, the Department has approved National Grid's proposals to continue its storm fund cost recovery mechanism, with several modifications.

D.P.U. 18-150, at 413-431; D.P.U. 15-155-A at 15-17; D.P.U. 15-155, at 75-79, 81-84; D.P.U. 09-39, at 205-213. National Grid's current storm fund cost recovery mechanism, approved in D.P.U. 18-150, set forth the following parameters: (1) for any storm in which National Grid incurred more than $1.55 million in incremental O&M costs (but less than $30.0 million in incremental O&M costs net of Verizon costs[165]), the Company is permitted to access the storm fund for reimbursement of only the portion of the costs that exceeds the $1.55 million threshold; (2) an annual $6.2 million O&M expense associated with four storm cost thresholds collected through base distribution rates (calculated by multiplying four storm cost thresholds per year by the $1.55 million storm cost threshold); (3) an annual $16.0 million contribution to the storm fund collected through base distribution rates; (4) a cap on a single storm-fund-eligible event O&M costs of $30.0 million (net of capitalization and Verizon costs); (5) carrying cost accrual on the monthly balance of the storm fund at the prime rate, incurred from the time of cost incurrence, and pending prudency review; (6) recovery of the incremental O&M costs for exogenous storms through the exogenous cost provision of the PBR mechanism subject to prudency review, should the combined balance of the storm fund and any costs associated with storms over $30.0 million exceed $75.0 million; and (7) extension of the storm fund replenishment factor ("SFRF")[166] through November 2023. D.P.U. 18-150, at 416-431.

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[165] Because of joint ownership of certain facilities, Verizon and National Grid share in the cost of storm restoration work (Exh. NECTA 1-1, Att. 2, at 44). D.P.U. 09-39, at 212-213 & n.122.

[166] In addition to the $16.0 million annual contribution to the storm fund collected through base distribution rates, the storm fund is also replenished through the SFRF. D.P.U. 18-150, at 420; D.P.U. 15-155, at 85. As explained below, the SFRF was approved in Massachusetts Electric Company and Nantucket Electric Company,

B. Company Proposal

National Grid proposes to continue its storm fund cost recovery mechanism, to maintain several components of the current storm fund, to modify several other components of the current storm fund, and to add a provision to the storm fund regarding future storm cost threshold recovery. The Company proposes to maintain: (1) a cap on a single storm-fund-eligible event O&M costs of $30.0 million (net of capitalization and Verizon costs); (2) carrying cost accrual on the monthly balance of the storm fund at the prime rate incurred from the time of cost incurrence, and, pending prudency review; and (3) recovery of the incremental O&M costs for exogenous storms through the exogenous cost provision of the PBR mechanism subject to prudency review, should the combined balance of the storm fund and any costs associated with storms over $30.0 million exceed $75.0 million (Exh. NG-RRP-1, at 99).

National Grid proposes several modifications to its current storm fund. First, the Company proposes to increase the storm cost threshold from $1.55 million to $1.80 million per storm event, a $250,000 increase to the storm cost threshold, to account for inflation (Exhs. NG-RRP-2, Sch. 34, at 4, line 37 (Rev. 4); DPU 6-13; Tr. 7, at 968; RR-DPU-23). Second, the Company proposes to increase by $10.0 million the annual O&M expense associated with storm cost thresholds collected through base distribution rates from $6.2 million to $16.2 million, which reflects an average of nine storm-fund-eligible events per fiscal year over the last five fiscal years at the proposed storm cost threshold of $1.80 million (Exh. NG-RRP-2,

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D.P.U. 13-59, at 19 (2013) to replenish the storm fund annually outside of base distribution rates for three years and minimize storm carrying costs on ratepayers. The SFRF expires on September 30, 2024. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-24, at 8-9 (2023).

Sch. 34 at 4, lines 39-40 (Rev. 4)). Third, the Company proposes to increase the annual contribution to the storm fund collected through base distribution rates from $16.0 million to $48.4 million,[167] an increase of $32.4 million, to reflect the average annual storm expense over the last five fiscal years (Exhs. NG-RRP-1, at 100; NG-RRP-2 Sch. 33, at 2, 4 (Rev. 4)). Fourth, National Grid proposes to increase the annual SFRF contribution from $41.6 million to $60.0 million over five years to recover a projected storm cost deficiency balance of approximately $243.1 million plus carrying charges (Exhs. NG-RRP-5-A Excel (Rev. 4); NG-PP-10 (Rev. 4)). Specifically, the Company proposes to transfer the estimated total storm fund deficiency balance to a separate regulatory asset and to reset the storm fund balance to zero (Exh. DPU 37-7). Fifth, National Grid proposes to implement a provision, as approved for NSTAR Electric in D.P.U. 22-22, whereby the Company would absorb two storm cost thresholds above the annual average number of storms set in the instant proceeding and recover the thresholds for any storms thereafter (Exh. NG-RRP-1, at 103). Conversely, in a year where at least one fewer than the average number of storms occurs, the Company would return to customers the storm cost thresholds for the number of events up to that one fewer than the average number that did not occur (Exh. NG-RRP-1, at 103-104).[168]

In addition to these modifications of its current storm fund, the Company makes two additional proposals. First, National Grid proposes to recover through the SFRF,

167 The precise amount is $48,420,756, but for ease of reference, the Department will refer to this amount as $48.4 million (Exh. NG-RRP-2 Sch. 33, at 2, 4 (Rev. 4)).

168 For example, using an average of nine storm-fund-eligible events, if there are five events in a given year, the Company would recover one storm cost threshold and return to customers the storm fund thresholds for three storm-fund-eligible events.

$18.6 million[169] in deferred storm cost thresholds associated with twelve storm-fund-eligible events that occurred during calendar years 2020 through 2022 (Exhs. NG-RRP-5A, at 1 (Rev. 4); NG-RRP-5-B at 1 (Rev. 4); NG-RRP-5-E at 1 (Rev. 4)). Second, to reduce administrative burden, the Company proposes to change the timing of its storm cost recovery filings so that it would make one single annual filing to include all storm-fund-eligible events occurring in that calendar year, within 18-24 months after the end of the calendar year (Exhs. NG-RRP-1, at 105; DPU 6-11; DPU 28-8).

C. Positions of the Parties

The Company repeats its storm fund proposals on brief (Company Brief at 510-516). National Grid argues that the ability to begin recovery of incremental O&M costs for certain (although not all) storm events during the proposed five-year stay-out period and the ability to begin accruing carrying charges on deferred storm costs at the same time the Company begins incurring associated financing costs, are both factors that help support the Company's access to capital (Company Brief at 506, citing Exhs. DPU 13-8; DPU 13-9). No intervenor commented on the Company's proposals.

169 The twelve excess deferred storm thresholds are composed of eight storm-fund-eligible events that occurred in 2020 (filed for recovery in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 21-75); two storm-fund-eligible events that occurred in 2021 (filed for recovery in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-78); and two storm-fund-eligible events that occurred in 2022 (filed for recovery in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-59) (Exh. NG-RRP-5-A at 1, line 3, line note 3(b) (Rev. 4)).

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. 18-150, at 413; D.P.U. 15-155, at 73; D.P.U. 13-90, at 13; D.P.U. 10-70, at 201-202; D.P.U. 09-39, at 206. The Department has recognized that the use of storm funds may shift the burden of cost recovery disproportionately to ratepayers without providing commensurate benefits. D.P.U. 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. 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 acceptable performance for emergency preparation and restoration of service for electric and gas companies); NSTAR Electric Company, D.P.U. 11-85-B/11-119-B, Order on Remand at 7-8 (2014) (imposing penalties for failure to communicate effectively with public safety and municipal officials regarding priority wires-down calls). 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 National Grid to devote substantial resources to achieving the desired results. Further, as recent history indicates, the frequency and severity of major storm events have increased (see, e.g., Exhs. NG-RRP-2, Sch. 33, at 4 (Rev. 4); DPU 28-6 (Supp.)). See e.g., Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-41 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-24 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-43 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 21-03 (pending); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 20-51 (pending).

The Department acknowledges that the Company's current storm fund cost recovery mechanism still has not provided the desired balance between cost recovery and rate stability. Specifically, the overall number of major storms since the Company's last base distribution rate case has contributed to National Grid's increasingly large storm fund deficiency balance, which the Company currently projects to be $243.1 million as of September 30, 2024 (as explained below), and which has expanded due to the accumulation of a significant amount in carrying charges associated with the deficiency balance (Exhs. NG-RRP-2, Sch. 33, at 4 (Rev. 4); NG-RRP-5-A at 1 (Rev. 4); NG-RRP-5-E at 1, line 61 (Rev. 4); DPU 28-6 (Supp.)). Because of the increased frequency and severity of storms since National Grid's last base distribution rate case, without a storm fund cost recovery mechanism, it is unlikely that during this timeframe the Company could have absorbed these costs without filing a base distribution rate case, or even multiple base distribution rate cases, which would likely have resulted in an increase in rates and other costs to ratepayers. Moreover, coupled with the five-year stay-out provision associated with the Department-approved PBR-O mechanism in the instant proceeding (see Section IV.C.4. above), a storm fund remains an important cost recovery mechanism. Therefore, we find that, if properly structured, allowing National Grid to continue operating a storm fund will likely provide for adequate recovery of storm costs in a manner that is designed to create rate stability. Based on the foregoing, the Department allows the Company to retain its storm fund with the several modifications, as discussed below.

3. Unmodified Storm Fund Components

The Company does not seek to change: (1) the cap on a single storm-fund-eligible event O&M costs of $30.0 million (net of capitalization and Verizon costs); (2) carrying cost accrual on the monthly balance of the storm fund at the prime rate incurred from the time of cost incurrence and subject to a prudency review; and (3) recovery of the incremental O&M costs for exogenous storms through the exogenous cost provision of the PBR mechanism (subject to prudency review) should the combined balance of the storm fund and any costs associated with storms over $30.0 million exceed $75.0 million (Exh. NG-RRP-1, at 99). The Department finds that these components of the storm fund shall continue consistent with the directives set forth in D.P.U. 18-150, the directives below, and in any subsequent Department decisions.

4. Modifications and Additions to the Storm Fund

a. Storm Cost Threshold

Currently, for any storm in which National Grid incurs more than $1.55 million in incremental O&M costs, the Company is permitted to access the storm fund for deferred recovery and reimbursement of only that portion of the costs that exceeds $1.55 million. D.P.U. 18-150, at 417-418. As noted above, the Company proposes to increase the storm cost threshold from $1.55 million to $1.80 million per storm event, a $250,000 increase to the storm cost threshold, to account for inflation (Exhs. NG-RRP-2, Sch. 34, at 4, line 37 (Rev. 4); DPU 6-13; Tr. 7, at 968; RR-DPU-23). The Company calculated the increase by comparing the

GDP-PI in the third quarter of calendar year 2019 to the GDP-PI in the first quarter of calendar year 2023 (Exh. NG-RRP-2, Sch. 34, at 4 (Rev. 4)). The Department has reviewed the Company's storm cost threshold calculation and finds it to be reasonable and consistent with Department precedent. D.P.U. 18-150, at 417. Accordingly, we approve a storm cost threshold of $1.80 million.

b. Annual Threshold O&M Expense in Base Distribution Rates

The Company proposes to increase the annual O&M expense associated with storm cost thresholds from $6.2 million to $16.2 million (Exhs. NG-RRP-2, Sch. 34 (Rev. 4); DPU 6-13, Atts.). The proposed increase is based on the storm cost threshold of $1.80 million multiplied by the average number of storm-fund-eligible events that occurred from April 1, 2018 through March 31, 2023, which was nine events (Exhs. NG-RRP-2, Sch. 33 (Rev. 4); Sch. 34, at 4 (Rev. 4); DPU 6-13, Atts.). The Department finds that the Company's proposed increase in the annual O&M expense collected in base distribution rates is consistent with our precedent. D.P.U. 18-150, at 416-418; D.P.U. 15-155, at 77. Accordingly, we approve an annual amount of $16.2 million in O&M expense collected in base distribution rates.

c. Annual Storm Fund Contribution

The Company proposes to increase the annual contribution to the storm fund collected through base distribution rates from $16.0 million to $48.4 million, an increase of $32.4 million, to reflect the average annual storm expense over the last five fiscal years (Exhs. NG-RRP-1, at 100; NG-RRP-2 Sch. 33, at 2, 4 (Rev. 4)). The Department has found that 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. 18-150, at 423. As evidenced by the number of major storms since the Company's last rate case and the resulting significant deficiency balance in the storm fund, the annual base distribution rate contribution amount of $16.0 million per year has proven to be insufficient to maintain rate stability (see, e.g., Exh. NG-RRP-5-E (Rev. 4)). Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-85, at 101, 106 (2016) (approving recovery of costs associated with 16 major storms); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 13-59 (2013) (approving recovery of $120.0 million in storm costs over three-year period). Thus, we conclude that an increase to the annual contribution to the storm fund is warranted. D.P.U. 23-80/D.P.U. 23-81, at 288; D.P.U. 22-22, at 274-275; D.P.U. 18-150, at 423; D.P.U. 17-05, at 551; D.P.U. 15-155, at 178.

The Department has considered the number of storm-fund-eligible events that have occurred between the Company's last base distribution rate case and the end of the test year, the incremental cost of these storms, and the number of storms that would not have been eligible for storm fund recovery had the $1.80 million storm cost threshold been in effect (Exh. NG-RRP-2, Sch. 33, at 4 (Rev. 4)). Further, we reviewed the calculation applied by the Company as the basis to establish its proposed annual storm fund contribution of approximately $48.4 million (Exhs. NG-RRP-1, at 99-100; NG-RRP-2, Sch. 33, at 4 (Rev. 4)). We find that the Company's proposed increase to the annual storm contribution is reasonable, appropriate, and consistent with precedent (Exhs. NG-RRP-1, at 99-100; NG-RRP-2, Sch. 33, at 2, 4 (Rev. 4)). D.P.U. 22-22, at 276; D.P.U. 18-150, at 424-427. Accordingly, the Department approves the Company's proposal to increase the annual storm fund contribution collected through base distribution rates to $48.4 million.

d. Extension of the SFRF

In D.P.U. 13-59, at 19, the Department approved the Company's request for a storm fund replenishment mechanism to replenish the then-storm fund deficiency balance and to reduce carrying charges. The Department extended the SFRF in two subsequent proceedings to continue recovery of the storm fund deficiency balance.[170] D.P.U. 15-155, at 84; D.P.U. 13-85, at 105. In D.P.U. 18-150, at 420, the Department approved the transfer of the then-storm fund balance to a separate regulatory asset. In addition, the Department approved an extension of the Company's SFRF through November 2023 to recover the regulatory asset (see M.D.P.U. No. 1409). D.P.U. 18-150, at 420. In D.P.U. 23-24, at 8-9, the Department approved a further ten-month extension of the SFRF through September 30, 2024, to recover the remaining deficit balance.

As noted above, National Grid proposes to increase the annual SFRF contribution from $41.6 million to $60.0 million over five years to recover the total projected storm cost deficiency balance of approximately $243.1 million[171] plus carrying charges (Exhs. NG-RRP-5-A, Excel (Rev. 4); NG-PP-10 (Rev. 4)). The Company also proposes to transfer the estimated total storm

170 In D.P.U. 15-155, at 85, the Department approved the Company's proposal to transfer the storm fund deficiency balance to a separate regulatory asset to be collected through the SFRF and to reset the storm fund balance to zero.

171 The Company estimates the total storm cost deficiency as of September 30, 2024, will be approximately $243.1 million, comprising: (1) a $253.0 million storm fund deficiency balance associated with storm-fund-eligible events occurring from October 1, 2019 through November 30, 2023; (2) an $18.6 million storm fund deficiency associated with deferred storm cost thresholds (discussed below); and (3) an offset of a $28.5 million SFRF cumulative residual surplus balance (Exhs. NG-RRP-5-A at 1 (Rev. 4); NG-RRP-5-B at 1 (Rev. 4); NG-RRP-5-E at 1 (Rev. 4)).

fund deficiency balance to a separate regulatory asset and to reset the storm fund balance to zero (Exh. DPU 37-7).

The record shows that without an increase to the annual SFRF contribution, the projected deficiency would not be extinguished until June 2032 at the currently projected prime rate, and ratepayers would incur approximately $37.8 million in additional carrying costs (Exh. NG-RRP-5-A at 3 (Rev. 4)). Based on the above considerations, the Department finds that it is appropriate to approve the Company's proposal to transfer the current storm cost deficiency balance at the end of September 2024 to a separate regulatory asset, to reset the storm fund balance to zero, and to increase the annual contribution to the SFRF to $60.0 million. Accordingly, the Department approves these modifications to the Company's storm fund.

The Company states that its storm fund has been in a deficit position since the first month of its approval (Exhs. NG-RRP-1, at 99; NG-RRP-5-E (Rev. 4)). Specifically, the Company's storm fund deficiency exceeded the symmetrical cap in November 2020, rendering the Company eligible to seek an alternative recovery method to reduce the balance in excess of the cap (Exh. NG-RRP-5-E (Rev. 4)). D.P.U. 09-39, at 208-209. The Company has not sought alternative recovery methods to recover the deficiency amount that exceeds the cap, and the deficiency balance has accumulated significantly since D.P.U. 18-150. In D.P.U. 23-80/D.P.U. 23-81, at 291, the Department found that it was appropriate for Unitil to provide a rationale in its annual electric reconciliation filing, should it elect to not file for recovery of storm costs in excess of the symmetrical cap. Consistent with that finding, the Department directs National Grid to provide a rationale in its annual electric reconciliation filing, should it elect to not adjust its storm fund recovery factors or seek an alternative recovery method associated with its storm fund deficiency balance in excess of the storm fund symmetrical cap.

e. Recovery of Future Storm Cost Thresholds

In D.P.U. 22-22, at 277-279, the Department found it reasonable to establish a measure of relief in years when the number of storm-fund-eligible events significantly exceeded the representative number in base distribution rates, which is referred to as the baseline. The Department, while recognizing that the frequency of storm-fund-eligible-events is inherently variable year to year, also found that it was more likely than not that the number of storm-fund-eligible events would increase in future years due to weather patterns and meteorological characteristics associated with climate change. D.P.U. 22-22, at 278. The Department found that a significant variation from NSTAR Electric's baseline of six storm-fund-eligible events was three additional storms per year. D.P.U. 22-22, at 279. Thus, the Department determined that NSTAR Electric could recover the storm cost thresholds associated with each storm-fund-eligible event subsequent to the eighth event in a given calendar year. D.P.U. 22-22, at 278-279. Conversely, if there were fewer than five storm-fund-eligible events in a given calendar year, the Company would return to customers the storm cost thresholds for the number of events fewer than five that did not occur. D.P.U. 22-22, at 278-279.

In the instant proceeding, National Grid proposes to implement a provision, as approved for NSTAR Electric in D.P.U. 22-22, whereby on a going forward basis the Company would absorb two storm cost thresholds above the annual average number of storms and recover the thresholds for any storms thereafter (Exh. NG-RRP-1, at 103). In a year where at least two less than the average number of storms occurs, the Company proposes to return to customers the storm cost thresholds for the number of events up to that one fewer than the average number that did not occur (Exh. NG-RRP-1, at 103-104).

The Department continues to recognize 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. D.P.U. 22-22, at 278; Massachusetts Electric Company, Nantucket Electric Company, and NSTAR Electric Company, D.P.U. 21-75/D.P.U. 21-76, at 22 (2021). Further, the Department finds 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. D.P.U. 22-22, at 278; D.P.U. 18-150, at 415. See also Inflation Reduction Act of 2022, P.L. 117-169, § 50153 (appropriating funds to address effects of changes in weather due to climate change on reliability and resiliency of electric grid). In fact, the record shows that over the past five fiscal years (i.e., April 1, 2018 through March 31, 2023), the Company experienced a total of 46 storm-fund-eligible events, for an average of nine events per year (Exhs. NG-RRP-1, at 99; NG-RRP-2, Sch. 33, at 4 (Rev. 4)). By comparison, in over nine years beginning on January 1, 2009 leading up to the Company's last base distribution rate case, the Company averaged just four storm-fund-eligible events per year. D.P.U. 18-150, at 399, 418-419.

Similar to our findings in D.P.U. 22-22, at 277-279, we find it reasonable to establish a measure of relief in years when the number of storm-fund-eligible events significantly exceeds the representative number in base distribution rates. D.P.U. 21-75/D.P.U. 21-76, at 22. As noted, the Company experienced an average of nine storm-fund-eligible events per fiscal year since 2018 (Exhs. NG-RRP-1, at 99-100; NG-RRP-2, Sch. 33, at 4, line 63 (Rev. 4)). Based on consideration of the frequency of storms and the proportion of average storm-fund-eligible events to the number of storm thresholds to absorb (i.e., one-third) that was approved in D.P.U. 22-22, we find that four additional storm-fund-eligible events per year is a significant variation from National Grid's average and, therefore, the Company must absorb three additional storm-fund-eligible events (i.e., one-third of the average number of events) before recovering storm cost thresholds. Further, although National Grid's test year is based on a fiscal year, we find it appropriate and consistent with our findings in D.P.U. 22-22, at 279, to set the timeframe for counting the storm-fund-eligible events as a calendar year. Thus, the Company will incur the storm cost thresholds for twelve storm-fund-eligible events that occur in a calendar year and recover the storm cost thresholds for any subsequent events in that same calendar year (i.e., the 13th storm-fund-eligible event and beyond).

Conversely, if there are fewer than eight storm-fund-eligible events in a calendar year, the Company will return to ratepayers the storm cost thresholds for the number of events fewer than eight that did not occur. The Department finds that this aspect of National Grid's proposal, in conjunction with the above modifications, appropriately balances the financial risk between the Company and ratepayers. D.P.U. 22-22, at 279.

5. Other Proposals

a. Recovery of Deferred Storm Cost Thresholds

In D.P.U. 22-22, at 280-281, the Department allowed NSTAR Electric to recover a certain number of storm cost thresholds for storm-fund-eligible events that occurred in 2020 and 2021 and exceeded the average number events per year since the company's last base distribution rate case. The Department determined that the costs that the Company proposed to collect did not retroactively change rates provided for prior service. D.P.U. 22-22, at 280, citing D.P.U. 10-70, at 216. Instead, the Department found that the increased costs were due to changes in weather patterns and increased storm activity since the Company's last base distribution rate case. D.P.U. 22-22, at 280. We determined that, consistent with its treatment of the recovery of future storm cost thresholds, a deviation of three or more storms above the representative level in rates at that time constituted a significant variation that was not anticipated in the approval of the storm fund mechanism. D.P.U. 22-22, at 280-281. Thus, we found that NSTAR Electric was to absorb two of the requested storm cost thresholds and recover the remaining number of thresholds. D.P.U. 22-22, at 281.

In the instant proceeding, and based on our decision in D.P.U. 22-22, National Grid proposes to recover through the SFRF, $18.6 million in deferred storm cost thresholds associated with twelve storm-fund-eligible events that occurred during calendar years 2020 through 2022 (Exh. NG-RRP-5A, at 1 (Rev. 4)). The Department previously approved deferred accounting treatment of the storm cost thresholds that exceeded those already recovered in base rates, less one threshold to represent the ebb and flow in the representative number of storm-fund-eligible events from year to year. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-59, at 14 (2023); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-78, at 13-14 (2023); D.P.U. 21-75/D.P.U. 21-76, at 28. The Company seeks to recover storm cost thresholds for eight storm-fund-eligible events that occurred in calendar year 2021; two storm-fund-eligible events that occurred in calendar year 2022; and two storm-fund-eligible events that occurred in calendar year 2022 (Exhs. NG-RRP-2, Sch. 33, at 4

(Rev. 4); NG-RRP-5A, at 1 (Rev. 4)). D.P.U. 23-59, at 4, 14; D.P.U. 22-78, at 4, 13-14; D.P.U. 21-75/D.P.U. 21-76, at 6, 28.[172]

In recognition of the increased storm activity since the Company's last base distribution rate case, and consistent with our findings in D.P.U. 22-22, at 280-281, the Department allows recovery of prior storm cost thresholds. We find, however, that not all of the storm cost thresholds identified by the Company are subject to recovery. Applying the method approved in D.P.U. 22-22, the Department determines that, consistent with our findings above, a significant variation of four storms over the representative level in base distribution rates in 2020 through 2022 (i.e., four storm-fund-eligible events) constitutes a significant variation that was not anticipated in the approval of the storm fund mechanism. D.P.U. 22-22, at 280-281. Thus, the Company may recover storm cost thresholds for seven storm-eligible-events in 2020, one storm-fund-eligible event in 2021, and one storm-fund-eligible event in 2022.[173] The total

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172 The Company's calculations are as follows: (1) for the eight storm cost thresholds in 2020 sought for recovery, there were 14 storm-fund-eligible events, less the representative amount of four in base distribution rates at that time, less two for ebb and flow based on the Company's reading of D.P.U. 22-22, at 281; (2) for the two storm cost thresholds in 2021, there were eight storm-fund-eligible events, less the four represented in base distribution rates, less two for ebb and flow; and (3) for the two storm cost thresholds in 2022, there were eight storm-fund-eligible events, less the four represented in base distribution rates, less two for ebb and flow (Exhs. NG-RRP-2, Sch. 33, at 4 (Rev. 4); NG-RRP-5A, at 1 (Rev. 4)).

173 The calculation is as follows: (1) for the seven storm cost thresholds in 2020 subject to recovery, there were 14 storm-fund-eligible events, less the representative amount of four in base distribution rates at that time, less three based on our findings in this proceeding; (2) for the one storm cost threshold in 2021, there were eight storm-fund-eligible events, less the four represented in base distribution rates, less three based on our findings in this proceeding; and (3) for the one storm cost threshold in 2022, there were eight storm-fund-eligible events, less the four represented in base distribution rates, less three based on our findings in this proceeding.

amount of recovery for these nine storm cost thresholds is $13.95 million (i.e., nine x $1.55 million storm cost threshold applicable in 2020 through 2022).

In its calculation of the deficiency balance sought for recovery through the SFRF, the Company included the deferred storm cost thresholds discussed above, which means that they would be subject to carrying charges (Exh. NG-RRP-5-A at 1-2 (Rev. 4)). To balance the burden of recovery of these expenses between the Company and ratepayers, we find that it is appropriate to exclude carrying charges for the recovery of the nine storm cost thresholds approved above. Further, we find this treatment is consistent with our decision in D.P.U. 22-22, at 280-281, where we did not provide for the recovery of carrying charges.[174] As such, the Company shall exclude the nine storm cost thresholds approved above from the carrying charge calculation related to the SFRF deficiency balance (see Exh. NG-RRP-5-A at 1-2 (Rev. 4)).

b. Timing of Storm Cost Recovery Filings

In D.P.U. 15-155-A, the Department directed the Company to file a petition for recovery of storm costs, including complete and final documentation and supporting testimony, as soon as practicable after finalizing the storm costs, and no later than six months after such costs are finalized. D.P.U. 15-155-A at 17. The Department also stated that to the extent National Grid is not able to prepare a final accounting of storm costs within six months of the storm-fund-eligible event, the Company must file a petition for storm cost recovery as soon as such information is complete. D.P.U. 15-155-A at 17. To date, the Company has not filed a complete storm cost

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[174] We note that in its recent storm cost filing, NSTAR Electric excludes carrying charges associated with the prior storm costs thresholds allowed in D.P.U. 22-22, at 280-281. NSTAR Electric Company, D.P.U. 23-124, Exh. ES-ANB-4, at 2 (September 27, 2024).

recovery filing in the year subsequent to the year of storm-fund-eligible event. D.P.U. 24-41; D.P.U. 23-24; D.P.U. 22-43; D.P.U. 21-03; D.P.U. 20-51.

In the instant proceeding, the Company proposes to change the timing of its storm cost recovery filings so that it would make one single annual filing to include all of the storms occurring in that calendar year, within 18-24 months after the end of the calendar year (Exhs. NG-RRP-1, at 105; DPU 6-11; DPU 28-8). The Company states that the basis of its proposal is to reduce administrative burden (Exhs. NG-RRP-1, at 105; DPU 6-11). The Department finds that the Company's proposal to make a single storm cost recovery filing should reduce administrative burden and allow for review, in one proceeding, of a full calendar year of storm costs. We find it unnecessary, however, to extend the timeline of the initial filing to 24 months. Thus, the Department directs the Company to make one single cost recovery filing for each calendar year's storm-fund-eligible events no later than 18 months after the end of the calendar year (e.g., storm cost recovery for calendar year 2024 storms must be filed by June 30, 2026), with any further documentation not prepared at the time of the initial filing to be submitted via supplemental filings under the same docket number.

E. Conclusion

Based on the above findings, the Department approves the continuation of the Company's storm fund with certain modifications and additions. The Company's storm fund shall take effect on October 1, 2024, apply to qualifying storm events that occur on or after that date, and continue for the duration of the Company's PBR-O plan, unless the Department directs otherwise. The storm fund shall contain the following parameters: (1) for any storm-fund-eligible event in which National Grid incurs more than $1.8 million in incremental

O&M costs (but less than $30.0 million in incremental O&M costs net of Verizon costs), the Company is permitted to access the storm fund for reimbursement of only the portion of the costs that exceeds the $1.8 million threshold; (2) an annual $16.2 million O&M expense associated with nine storm cost thresholds collected through base distribution rates (calculated by multiplying nine cost thresholds per year by the $1.8 million storm cost threshold); (3) an annual $48.4 million contribution to the storm fund collected through base distribution rates; (4) a cap on a single storm-fund-eligible event O&M costs of $30.0 million (net of capitalization and Verizon costs); (5) carrying cost accrual on the monthly balance of the storm fund at the prime rate, incurred from the time of cost incurrence, and subject to a prudency review; (6) the recovery of the incremental O&M costs for exogenous storms through the exogenous cost provision of the PBR mechanism (subject to prudency review) should the combined balance of the storm fund and any costs associated with storms over $30.0 million exceed $75.0 million; (7) the transfer of the SFRF estimated total storm fund deficiency balance of approximately $243.1 million to a separate regulatory asset, a reset of the storm fund balance to zero, and an increase to the annual SFRF contribution from $41.6 million to $60.0 million over five years to recover the projected storm cost deficiency balance, plus carrying charges; and (8) an allowance for recovery of future storm cost thresholds beginning with the 13th storm-fund-eligible event in a calendar year and thereafter, and a provision that if there are fewer than eight storm-fund-eligible events in a calendar year for the Company to return to ratepayers the storm cost thresholds for the number of events fewer than eight that did not occur.

Further, the Company may recover $13.95 million through the SFRF, which represents the $1.55 million storm cost threshold for seven storm cost thresholds that occurred in 2020, one storm cost threshold that occurred in 2021, and one storm cost threshold that occurred in 2022, without carrying charges. In addition, the Company shall make one single cost recovery filing for each calendar year's storm-fund-eligible events no later than 18 months after the end of the calendar year, with any further documentation not prepared at the time of the initial filing to be submitted via supplemental filings under the same docket number. The Company shall file a revised storm fund replenishment provision tariff consistent with the findings and directives set forth above.

XI. SALE OF NARRAGANSETT ELECTRIC COMPANY

A. Background

On May 4, 2021, National Grid USA filed a petition requesting that the Department waive its jurisdiction under G.L. c. 164, § 96(c) over a transaction involving the sale of all of National Grid USA's outstanding common stock ownership of its wholly owned subsidiary Narragansett Electric to PPL Rhode Island, i.e., the Rhode Island Sale (Exh. NG-JR-1, at 2, 5).[175] National Grid USA, D.P.U. 21-60, at 1, 38-39 (2021).

As part of National Grid USA's petition, its Massachusetts subsidiaries MECo, Nantucket Electric, and Boston Gas Company ("Boston Gas") agreed to provide a cost

[175] General Laws c. 164, § 96(c), among other things, requires Department approval of transactions involving holding companies subject to G.L. c. 164 where those transactions would result in a change of the company's control over any foreign electric or gas company. General Laws c. 164, § 96(c) further provides that a holding company may request a waiver of this subsection by the Department by submission of an affidavit with explanation and documentation substantially supporting a conclusion that the proposed transaction will have no adverse impact on the petitioning company's subsidiaries subject to the Department's jurisdiction. The Department may grant a waiver if it agrees with the conclusion provided in the affidavit. G.L. c. 164, § 96(c).

mitigation study ("Cost Mitigation Study"), examined by a third party, in their next base distribution rate proceedings to present a full accounting of National Grid USA's cost mitigation efforts related to the Rhode Island Sale. D.P.U. 21-60, at 21, 31-32. National Grid USA represented that it did not anticipate that the Rhode Island Sale would result in its Massachusetts subsidiaries incurring any transaction costs or suffering adverse impacts on financing their operations. D.P.U. 21-60, at 32. In the Order approving the waiver, the Department noted that MECo and Nantucket Electric at that time were operating under a PBR plan and that any rate impacts from the Rhode Island Sale would be subject to regulatory scrutiny following the expiration of the PBR plan. D.P.U. 21-60, at 33-34. The Department determined that based on the data available in that proceeding, MECo and Nantucket Electric should be able to absorb any unmitigated cost impacts during the term of the PBR plan. D.P.U. 21-60, at 34.

On July 16, 2021, the Department granted National Grid USA's waiver petition. D.P.U. 21-60, at 41. On August 12, 2021, the Attorney General appealed the Department's decision to the Massachusetts Supreme Judicial Court. On March 25, 2022, National Grid USA, its Massachusetts subsidiaries, and the Attorney General entered into a settlement ("Settlement"), and the Attorney General subsequently withdrew the appeal. On May 25, 2022, the Rhode Island Sale was finalized.

B. Settlement

The Settlement stipulated that in their next base distribution rate proceedings, National Grid USA's Massachusetts subsidiaries must use the Cost Mitigation Study to quantify the indirectly attributable service company ("IASC")[176] pre-mitigated stranded cost[177] impact of the Rhode Island Sale and establish a process to demonstrate that these costs are eliminated, mitigated, and/or absorbed by National Grid USA (Exh. NG-JR-3, at 4).[178] In particular with respect to the Company, the Settlement provided that MECo and Nantucket shall present a full accounting of National Grid USA's stranded cost mitigation efforts and the results through December 31, 2022, and thereafter (Exh. NG-JG-3, at 11). The Settlement also stated that National Grid shall demonstrate that the stranded costs are fully eliminated, mitigated, and/or absorbed, at least in relation to the proportion applicable to its customers, and shall request a finding from the Department to that effect (Exh. NG-JG-3, at 11).[179]

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176 IASC allocation amounts are set forth in National Grid USA's cost allocation manual provided in the instant proceeding (Exh. NG-JR-4). IASC costs are allocated based on a three-point "cost-causation" formula consisting of: (1) net plant; (2) net margin; and (3) net O&M expense.

177 As defined in the Settlement, pre-mitigated IASC stranded costs are IASC costs in existence as of December 31, 2021 that would represent incremental, future adverse impact for customers of National Grid USA's Massachusetts subsidiaries arising out of the loss of Narragansett Electric's share of IASC costs if not eliminated, mitigated, or otherwise absorbed by National Grid USA (Exhs. NG-JR-2, at 16; NG-JR-3 at 7). See also D.P.U. 21-60 Settlement Annual Report at 1 n.4 (June 28, 2024)).

178 The Settlement contemplated that MECo and Nantucket Electric would file a base distribution rate case in 2023, and that Boston Gas would file a base distribution rate case in 2026 (Exh. NG-JG-3, at 11-12).

179 The Settlement provides that to the extent that any capitalized or deferred IASC costs are incurred after the Rhode Island Sale and are proposed for cost recovery through base distribution rates, National Grid USA, through its Massachusetts subsidiaries, shall: (1) identify the amount of allocated IASC costs in the proposed revenue requirement at the end of the test year; and (2) compare that amount to the IASC costs allocated to the respective company in calendar year 2021 (Exhs. NG-JR-1, at 10-11; NG-JR-3, at 9-10). To the extent that the test-year allocation of IASC costs exceeds the IASC cost allocation

The Settlement noted that in 2021, prior to the Narragansett Electric's divestiture, National Grid USA's Massachusetts subsidiaries were allocated approximately 29.9 percent of the IASC costs (Exh. NG-JR-3, at 7, 25). The Settlement estimated that because of the divestiture, the allocated share of those costs would increase to approximately 33.73 percent, all else equal, and represent a recurring adverse impact of $29,051,675, if not mitigated by National Grid USA (Exhs. NG-JR-2, at 5; NG-JR-3, at 7, 25; DPU 10-14). As part of the Settlement, National Grid USA accepted the obligation to mitigate adverse rate impacts to its Massachusetts subsidiaries' customers over a five-year period or absorb up to the full potential IASC stranded cost amount of $29,051,675 (Exhs. NG-JR-2, at 3, 5; NG-JR-3, at 2, 7, 10, 25).[180]

The Settlement included the creation of a $5.0 million regulatory liability to support annual refunds of the Rhode Island Sale cost impacts that have the potential to occur within the context of National Grid USA's Massachusetts subsidiaries' reconciling rate mechanisms (Exh. NG-JR-3, at 4, 9). The Settlement also committed National Grid USA to a one-time bill

in 2021, the Attorney General may challenge the incremental difference in the associated base distribution rate proceeding (Exhs. NG-JR-1, at 10-11; NG-JR-3, at 9-10).

180 More specifically, the Settlement provides that, should the Department find that the stranded costs are fully eliminated, mitigated, and/or absorbed following Boston Gas' next base distribution rate case, then National Grid USA's and its Massachusetts subsidiaries' stranded cost obligations shall terminate, subject to the exhaustion of expiration of any judicial appeal (Exh. NG-JR-3, at 12). If the Department determines that the Rhode Island Sale stranded costs are not fully mitigated, eliminated and/or absorbed, National Grid USA and its Massachusetts subsidiaries agree to forego IASC potential stranded cost recovery of up to $29,051,675 (Exhs. NG-JR-2, at 5; NG-JR-3, at 10, 25).

credit of $7.9 million[181] to its Massachusetts subsidiaries' customers as a proxy for certain cost increases that have the potential to occur over the five years following the Rhode Island Sale (Exhs. NG-JR-3, at 4, 13-14; DPU 10-15). Further, the Settlement committed National Grid USA to a contribution of $5.0 million within 30 days after the Rhode Island Sale transaction closing to: (1) forgive $3.0 million in arrearages over 90 days for MECo and Nantucket Electric customers; (2) forgive $1.0 million in arrearages over 90 days for Boston Gas customers; and (3) provide $1.0 million to the Attorney General's Residential Energy Assistance Grant Program (Exhs. NG-JR-3, at 4, 13; DPU 10-15).[182]

The Settlement required National Grid USA's Massachusetts subsidiaries to file annual reports detailing the stranded costs and National Grid USA's efforts to reduce those costs, as well as any non-mitigated amounts charged to its Massachusetts subsidiaries through the end of the most recent calendar year (Exhs. NG-JR-2, at 5; NG-JR-3, at 10). The Settlement required that annual reports be filed on June 30 of each year and verified by independent public accountants (Exhs. NG-JR-2, at 5; NG-JR-3, at 10-11). Pursuant to the Settlement, the annual

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181 The total $7.9 million bill credit was split among the customers of National Grid USA's Massachusetts subsidiaries based on the ratio of the most recently approved base distribution revenue requirement. D.P.U. 21-60, Filing Letter (June 24, 2022).

182 The $7.9 million one-time bill credit, $3.0 million electric arrearage forgiveness, and $1.0 million gas arrearage forgiveness were recorded directly into the accounting records of the appropriate National Grid USA's Massachusetts subsidiaries and therefore not included in the Cost Mitigation Study analysis (Exh. DPU 10-15). The $1.0 million contribution to the Attorney General's Residential Energy Assistance Program is included in the absorbed IASC costs in the Cost Mitigation Study analysis (Exh. DPU 10-15).

reporting requirement shall terminate once the Department has rendered a determination on the stranded costs in the Boston Gas' expected base distribution rate case (Exh. NG-JR-3, at 11).[183]

C. Cost Mitigation Study

In the instant proceeding, the Company provided a Cost Mitigation Study through December 31, 2022, and through the test year end (Exhs. NG-JR-1, at 16; NG-JR-2). National Grid USA engaged Ernst and Young to assist in preparing the Cost Mitigation Study (Exhs. NG-JR-1, at 16; NG-JR-2, at 3). In particular, Ernst and Young's efforts included interviews and walkthroughs with various internal employees, as well as data gathering, research, and analysis of over 41 different organizational functions (Exhs. NG-JR-1, at 17; NG-JR-2, at 3).

The Company's Cost Mitigation Study presented two distinct and separate analyses that were designed to identify the pre-mitigated stranded costs that would be charged to MECo and Nantucket Electric as a result of the Rhode Island Sale (Exhs. NG-JR-1, at 15-16; NG-JR-2, at 8-35). The first analysis compared the Company's cost data for calendar year 2021 to the data for fiscal year 2023 (Exhs. NG-JR-1, at 17-25; NG-JR-2, at 7-17). This analysis showed approximately $5.9 million in incremental pre-mitigated IASC costs for the Company in fiscal year 2023 (also the test year) as compared to calendar year 2021 following the Rhode Island Sale (Exhs. NG-JR-1, at 4, 17-18, 34-35; NG-JR-2, at 17, Table 5; DPU 10-13). The second analysis compared the Company's cost data for calendar year 2021 to the data for calendar year 2022 (Exhs. NG-JR-1, at 17-18, 25-31). This analysis showed approximately $3.4 million in

[183] Thus, the final annual report is expected to be submitted by June 30, 2027 (Exh. NG-JG-3, at 11 n.3).

incremental pre-mitigated ISAC costs for the Company in calendar year 2022 as compared to calendar year 2021 following the Rhode Island Sale (Exh. NG-JR-1, at 18, 25-31, 34). Both analyses reviewed three categories of shared costs (i.e., directly assignable, directly attributable, and IASC costs) with a particular focus on IASC costs given their general shared-cost nature (Exhs. NG-JR-1, at 17; NG-JR-2, at 6, 8; DPU 6-8). Ernst and Young analyzed the cost allocation method and process undertaken by National Grid USA to exclude Narragansett Electric from the cost pool after completion of the Rhode Island Sale (Exh. NG-JR-1, at 17; NG-JR-2, at 30-31).

The Cost Mitigation Study also presented National Grid USA's and the Company's efforts to mitigate stranded costs post-Rhode Island Sale. According to the Cost Mitigation Study, the Company achieved approximately $15.9 million in cost mitigation savings following the Rhode Island sale in two general areas. First, the Company reduced its overall allocated facilities expense by $4.1 million through early termination of original leases (i.e., Reservoir Woods building in Waltham, Massachusetts and Metro Tech building in Brooklyn, New York), and the relocation to smaller facilities (i.e., Data Drive building in Waltham, Massachusetts, One Beacon building in Boston, Massachusetts, and Hanson Place building in Brooklyn, New York) (Exhs. NG-JR-2, at 18; NG-JR-6; AG 7-60). Second, National Grid USA reduced its overall calendar year 2021 base labor costs by $11.8 million[184] through organizational restructuring (Exhs. NG-JR-1, at 34; NG-JR-2, at 19; NG-JR-6, at 2; DPU 10-15). In March 2021, National

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184 In its initial filing, the Company calculated $12.9 million in base labor cost savings for the Company (Exh. NG-JR-1, at 33). National Grid adjusted this figure to $11.8 million to account for costs that were already captured in its pre-mitigated stranded costs analysis (Exhs. NG-JR-2, at 19; DPU 10-15).

Grid USA implemented an organization-wide cost-savings initiative to reduce certain executive positions and labor-related expenses (Exhs. NG-JR-2, at 18; NG-JR-6, at 2). In total, National Grid USA removed five executive positions and 200 management positions and assigned to National Grid the resulting allocated cost reductions associated with those eliminated positions (Exh. DPU 6-4).

The Company states that the $15.9 million post-Rhode Island Sale cost mitigation savings exceeds the $5.9 million in incremental pre-mitigated stranded costs from the calendar year 2021 to fiscal year 2023 analysis, and the $3.4 million in incremental pre-mitigated IASC stranded costs from the calendar years 2021 to 2022 analysis (Exh. NG-JR-1, at 18, 34). As such, the Company submits that National Grid USA, through the Company, has fully eliminated, mitigated, or absorbed all of the stranded costs attributable to the Company resulting from the Rhode Island Sale (Exhs. NG-JR-1, at 16, 35-36; NG-JR-2, at 4, 20). The Company requests that the Department find that National Grid USA's obligations under the Settlement shall be terminated as to the Company (Exh. NG-JR-1, at 36).

D. Positions of the Parties

1. Attorney General

The Attorney General argues that the Department should reject the Company's request to terminate the obligations under the Settlement (Attorney General Brief at 100). The Attorney General contends that the Company did not submit the required annual report in 2023 to include the itemization or quantification of IASC costs, but rather filed a "status update" that lacked the details required under the Settlement (Attorney General Brief at 101, citing Exh. NG-JR-Rebuttal-1, at 6). The Attorney General also asserts that National Grid failed to provide the necessary information to determine whether the Company has mitigated the costs related to the Rhode Island Sale (Attorney General Reply Brief at 23, citing Exhs. AG-JD-1, at 16-17; AG-JD-Surrebuttal-1, at 7-9).

Further, the Attorney General contends that through the Settlement, the Company agreed to mitigate any adverse impacts resulting from the Rhode Island Sale for five years and through Boston Gas' next base distribution rate proceeding (Attorney General Brief at 100). The Attorney General maintains that since only two years have passed since the Rhode Island Sale and the Department has not yet reviewed Boston Gas' mitigation efforts, any termination of National Grid USA's obligations under the Settlement is premature (Attorney General Brief at 100).

2. Company

National Grid argues that it has fully eliminated, mitigated, and/or absorbed any potential stranded costs resulting from the Rhode Island Sale as it relates to the Company's customers (Company Brief at 498, citing Exhs. NG-JR-1, at 35; NG-JR-Rebuttal-1, at 6; NG-JR-Rebuttal-2). Regarding the Attorney General's arguments, the Company contends that it advised the Attorney General that cost information was not yet available at the time of the annual report but would be provided as part of the filings in the instant proceeding (Company Brief at 502-503). Thus, the Company asserts that it complied with the Settlement filing requirements (Company Brief at 502-503). Further, National Grid claims that the language of the Settlement, coupled with the mitigation details in the Cost Mitigation Study, support a finding that National Grid USA should be released of any further obligations as to the Company, and that waiting for

Boston Gas' base distribution rate proceeding to conclude is unnecessary (Company Brief at 487-488, 500-502, citing Exhs. NG-JR-2; NG-JR-3, at 10-11).

E. Analysis and Findings

Pursuant to the Department's Order in D.P.U. 21-60 and the subsequent Settlement, the Company provided a Cost Mitigation Study, reviewed by an independent third-party, to detail efforts to mitigate IASC stranded costs resulting from the Rhode Island Sale (Exhs. NG-JR-2; NG-JR-3, at 6). D.P.U. 21-60, at 21, 31-32. The record demonstrates that National Grid generated \$15.9 million of post-Rhode Island Sale cost mitigation savings (\$4.1 million in reduced facilities expenses and \$11.8 million in reduced labor expense), which exceeds the \$5.9 million in incremental, pre-mitigated stranded costs from the calendar year 2021 to fiscal year 2023 analysis, and the \$3.4 million in incremental, pre-mitigated IASC stranded costs from the calendar years 2021 to 2022 analysis (Exhs. NG-JR-1, at 18-34; NG-JR-2; DPU 6-2). After reviewing the Cost Mitigation Study and the supporting information in the record in this proceeding, the Department is satisfied that the Company's share of IASC stranded costs related to the Rhode Island Sale have been fully eliminated, mitigated, and/or absorbed (see e.g., Exhs. NG-JR-1; NG-JR-2; NG-JR-3; DPU 6-1 through DPU 6-9; DPU 10-13; DPU 10-15; DPU 10-14; AG 7-60; AG 7-61; AG 9-2; AG 10-29 through AG 10-36; Tr. 1, at 62-83; RR-AG-3).

As noted above, the Attorney General argues that the Department should reject the Company's request to terminate the obligations under the Settlement because the Company failed to provide an annual report (Attorney General Brief at 100-101). The terms of the Settlement require the Company to submit annual reports on June 30 of each year to, among other things, detail efforts to reduce stranded costs and any non-mitigated amounts charged to National Grid USA's Massachusetts subsidiaries through the end of the most recent calendar year, and to itemize and quantify the total, non-mitigated IASC costs, if any, charged to each of the Massachusetts subsidiaries through the end of the calendar year (Exh. NG-JR-3, at 10-11). On June 30, 2023, the Company filed a status report in which it described certain mitigation efforts to date, noted that it has retained Ernst and Young to assist with the Cost Mitigation Study, and advised that a full report would be provided in conjunction with the instant base distribution rate case. D.P.U. 21-60, Status Update on Annual Report (June 30, 2023). Given that the Company and Ernst and Young had not completed the cost mitigation assessment, a detailed report on the status of stranded costs was not available. Thus, we find the Company's status update was reasonable under the circumstances. Further, the Company provided the Cost Mitigation Study with the initial filing in the instant proceeding thus fulfilling its commitment from the status update (Exh. NG-JR-2). The Attorney General had ample opportunity to evaluate the report, issue discovery, and conduct cross examination on the Company's cost mitigation efforts in the context of compliance with the Settlement. Thus, we find that the Company's failure to provide a detailed annual report, in strict compliance with the terms of the Settlement, did not prejudice the Attorney General.[185]

The Attorney General also maintains that inasmuch as only two years have passed since the Rhode Island Sale and the Department has not yet reviewed Boston Gas' mitigation efforts, any termination of National Grid USA's obligations under the Settlement is premature (Attorney

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185 We note that the Company also provided a detailed annual report by June 30, 2024, in compliance with the Settlement. D.P.U. 21-60, 2023 Annual Report (June 28, 2024).

General Brief at 100). As noted above, the Company argues that the Settlement allows for termination of National Grid USA's obligations as to the Company in this proceeding (Company Brief at 487-488, 500-502, citing Exhs. NG-JR-2; NG-JR-3, at 10-11). We agree with the Attorney General that termination of National Grid USA's obligations is premature. We find that the Settlement is clear and unambiguous as to the Company's obligations. Section 2.13 of the Settlement provides that the requirement for annual reports shall terminate once the Department has rendered a determination on the stranded costs in Boston Gas' expected base distribution rate case (Exh. NG-JR-3, at 10-11). Similarly, Section 2.16 of the Settlement provides that if the Department issues a finding that National Grid USA has demonstrated that the stranded costs are fully eliminated, mitigated, and/or absorbed following Boston Gas' expected base distribution rate case, then National Grid USA's and its Massachusetts subsidiaries' obligations under the Settlement shall terminate, subject to the exhaustion or expiration of any judicial appeal (Exh. NG-JR-3, at 12). Based on these considerations, we conclude that National Grid USA, through its Massachusetts subsidiaries, shall continue to submit annual reports consistent with Section 2.13 of the Settlement. The Department will evaluate the termination of this obligation consistent with our expected review of Boston Gas' stranded cost mitigation filing pursuant to Section 2.16 of the Settlement.

XII. NATIONAL GRID CRIMINAL INVESTIGATION

A. Introduction

On June 17, 2021, five former National Grid USA employees were arrested on federal charges of fraud and bribery (Exh. AG 1-2, Att. 5, at 40). D.P.U. 20-120, at 368. The defendants were alleged to have intentionally evaded National Grid USA's procurement controls to steer facilities services contracts to favored vendors for several years, in exchange for bribes and kickbacks in the form of both cash and other items of value, such as vehicles, tuition payments, home renovations, personal electronic devices, and travel and vacation expenses. D.P.U. 20-120, at 368.[186] In response, the New York Department of Public Service ("NYDPS") commenced an investigation of National Grid USA and two of its New York affiliates, The Brooklyn Union Gas Company and Keyspan East Gas Corporation, regarding the allegations; that investigation was docketed as Case No. 21-M-0351 and remains ongoing (Exh. DPU 2-14). National Grid USA also commissioned an independent review of its internal controls and procedures bearing on procurement to identify areas for improvement (Exh. DPU 2-13, Att.). In D.P.U. 20-120, at 375, the Department stated its intention to conduct its own investigation upon the completion of NYDPS' investigation.[187] None of the parties addressed the criminal investigation on brief.

B. Analysis and Findings

It is axiomatic that payments associated with criminal activities, whether in the form of bribes or kickbacks, are not eligible for rate recovery as a matter of public policy.

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186 These activities and the associated costs predominantly pertain to shared New York facilities that house NGSC employees who provide services to National Grid USA's operating affiliates, including the Company. D.P.U. 20-120, at 368 n.183. All five defendants ultimately pleaded guilty in federal court pursuant to plea agreements (Exh. AG 1-2, Att. 5, at 40). National Grid USA was considered a victim of this misconduct, and fully cooperated with the United States Attorney for the Eastern District of New York, the Federal Bureau of Investigation, and the New York Department of Public Service. D.P.U. 20-120, at 368.

187 In doing so, the Department reserved the right to commence its investigation before the completion of the NYDPS investigation, depending upon developments at the NYDPS. D.P.U. 20-120, at 376-377.

D.P.U. 20-120, at 373. The scope of misconduct included bid rigging, favoritism with respect to no-bid contracts, and other behaviors that deceived NGSC into making unwarranted payments to contractors, the costs of which were allocated to NGSC's affiliates, including the Company. D.P.U. 20-120, at 373. Such behaviors are adverse to the best interests of National Grid, its customers, and other contractors. D.P.U. 20-120, at 374.

In D.P.U. 20-120, at 375, the Department announced its intention to open an investigation into the alleged criminal activities then undergoing investigation by the U.S. Attorney and NYDPS. Our investigation is intended to identify any costs associated with these activities that may have been passed on to Massachusetts affiliates of National Grid USA and their customers, as well as consider the appropriate vehicle by which any unwarranted costs would be returned to ratepayers. D.P.U. 20-120, at 375. The Department determined that because the NYDPS investigation was likely to provide valuable evidence related to vendor contracts and the legitimacy of their underlying charges, our own investigative proceeding would be deferred until the conclusion of the NYDPS investigation, unless otherwise warranted by later events. D.P.U. 20-120, at 376-377.

While the federal investigation has concluded, the NYDPS investigation remains ongoing (Exh. DPU 2-14).[188] The Department continues to find it appropriate to allow the NYDPS investigation to conclude before opening our own investigation. In reaching this decision, the

[188] The complete NYDPS docket is available online. Proceeding to Examine Certain Programs and Related Capital and Operation and Maintenance Expenditures of National Grid USA, available at https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=21-M-0351&CaseSearch=Search (last accessed September 26, 2024).

Department expects National Grid's continued cooperation in our own investigation, regardless of the outcome of the NYDPS investigation.[189]

XIII. NATIONAL GRID MANAGEMENT AUDIT

A. Introduction

Whether a regulated company is conducting its business in an appropriate manner in terms of efficiency of operations and productivity of its employees has been an ongoing concern of the Department. D.P.U. 19991, at 62-63; D.P.U. 17795-A at 24. To address this concern, the Department has previously required management studies or audits.[190] See, e.g., D.T.E. 05-27, at 417-419; D.P.U. 89-114/90-331/91-80 (Phase One) at 197-198; D.P.U. 19991, at 62-63; D.P.U. 17795-A at 24. The Department has general supervisory authority to ensure that a company's management decisions are made and carried out in a manner consistent with the public interest. D.P.U. 89-114/90-331/90-81 (Phase One) at 193, citing G.L. c. 164, § 76. The Supreme Judicial Court has acknowledged that the Department possesses broad investigative and supervisory authority over jurisdictional companies. Boston Edison, 375 Mass. 1, 44.[191]

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189 For example, the Company represents that if the New York investigation is ultimately resolved through the approval of a settlement, such a settlement will not hinder the Department's ability to conduct its own investigation (RR-DPU-1). Any attempt to use a settlement as a shield against the Department's own inquiry would be ill-advised.

190 Management audits offer a useful diagnostic tool in the examination of how well an organization is managed, identifying areas of effective management and areas for improvement.

191 Where the Department imposed a requirement that Boston Edison Company demonstrate improvements to its efficiencies and productivity, the Supreme Judicial Court affirmed the Department's directives and found that the "efficiency of Boston Edison and the magnitude of its construction program are matters of legitimate public interest." Boston Edison, 375 Mass. 1, 44.

B. Overview

In National Grid's previous base distribution rate case, the Department determined that, given the Company's recent history regarding the efficiency of operations and productivity of its management and personnel, the Company and its ratepayers would benefit from a more in-depth review of management practices through a comprehensive independent management audit. D.P.U. 18-150, at 499-502. Pursuant to its supervisory authority, the Department announced that we would open an investigation to address, at a minimum: (1) the Company's strategic planning processes; (2) National Grid's staffing decisions and the extent to which they affect the Company's efficiency of operations and the productivity of its employees; and (3) potential management problems through to the highest levels of the organization, as well as potential management issues related to National Grid's relationship with NGSC. D.P.U. 18-150, at 502. In directing such an audit, the Department stated that we would determine the final scope of and procedures for the audit after comment from interested stakeholders and that the costs of conducting the audit would be borne by National Grid shareholders. D.P.U. 18-150, at 503.

On November 25, 2019, the Department opened an investigation to undertake an independent audit regarding various aspects of the Company's management practices and docketed the matter as D.P.U. 19-117. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 19-117, Memorandum Opening Docket (November 25, 2019). On May 19, 2020, the Department approved the selection of FTI Consulting ("FTI") to perform the audit. On March 29, 2021, FTI filed its final report ("FTI Report") (Exh. AG 1-8, Att. 8).[192] The FTI

[192] In the interim, the Attorney General moved to replace FTI as auditor based on allegations of bias and conflict of interest with the Company; the Department denied the motion.

Report encompassed 25 findings and made 54 recommendations in the areas of strategic planning, staffing decisions, the Company's relations with NGSC, IT, EVs, and interconnection processes (Exh. AG 1-8, Att. at 20-31).[193] During the proceeding, the Company and the Attorney General agreed that National Grid should implement the FTI Report's recommendations, and the Department subsequently directed the Company to do so. D.P.U. 19-117-B at 13, 15. The Department stated that we would evaluate National Grid's implementation of the FTI Report's recommendations during the Company's next base distribution rate proceeding and directed the Company to file in that proceeding a comprehensive update on its progress implementing the FTI Report's recommendations, including implementation time frames. D.P.U. 19-117-B at 13. The Department also stated that we would consider the time and cost associated with the implementation of each recommendation, as well as whether the solution adequately addressed the recommendation, all of which would inform the Department both as to whether recovery of the associated costs was warranted and on determining the Company's overall ROE. D.P.U. 19-117-B at 13. In doing so, the Department noted that merely implementing the FTI Report's recommendations would not guarantee cost recovery. D.P.U. 19-117-B at 13.

D.P.U. 19-117-A, Interlocutory Order on Attorney General's Motion to Replace Auditor at 12-18 (February 12, 2021).

193 On April 30, 2021, the Company filed its response to the FTI Report setting forth its proposal for implementation, including steps that were already underway, as well as plans for building on existing processes to achieve the objectives of FTI's recommendations (Exh. AG 7-62, Att. at 3). The Attorney General filed comments on the FTI Report on June 30, 2021, to which the Company filed reply comments on July 21, 2021. D.P.U. 19-117-A at 5.

Further, the Department noted that the Company did not propose a thorough plan to address every FTI Report recommendation and that many of the Company-proposed timeframes were unclear (i.e., a number of months provided with no start date). D.P.U. 19-117-B at 13-14. The Department stated that the Company must demonstrate that it has implemented the FTI Report recommendations in a timely, efficient, and prudent manner to address the inadequacies identified by FTI. D.P.U. 19-117-B at 14. The Department stated that we would closely review the Company's investments in each solution to determine whether they are prudent, and we encouraged National Grid to prioritize the FTI Report's recommendations and accelerate timeframes where possible. D.P.U. 19-117-B at 14.

C. Management Audit Compliance

In its initial filing in the instant proceeding, National Grid reported the FTI Report resulted in a total of 104 compliance actions for the Company to complete, and that as of November 16, 2023 (i.e., the date the Company filed this rate case), the Company had acted on the recommended actions (Exh. NG-MECO-1, at 35-36). During the proceeding, the Company submitted an audit implementation report detailing the implementation of each recommendation contained in the FTI Report (Exh. AG 7-62, Att.).[194] According to the Company, of the FTI Report's 54 recommendations, it had adopted 43 recommendations, implemented modified versions of ten recommendations, and rejected one recommendation[195] (Exh. AG 7-62, Att.

194 National Grid submitted its audit implementation report in D.P.U. 19-117 on December 11, 2023.

195 The FTI Report recommended that the Company examine its financial workbook template to determine whether the current level of detail was necessary, implement any updates, and provide appropriate employee training (Exh. AG 1-8, Att. 8, at 26). The

at 4-69). The Company represented it had implemented these changes as part of its normal course of business and thus did not incur any incremental costs or resources during the implementation process (Exhs. NG-RRP-Rebuttal-1, at 25, 29; AG 7-62; AG 7-63). Thus, the Company stated that there are no non-recurring costs related to implementing the FTI Report recommendations (Exh. NG-RRP-Rebuttal-1, at 25, 29).[196]

D. Positions of the Parties

1. Attorney General

The Attorney General argues that National Grid failed to properly track the costs of implementing each FTI Report recommendation, in direct violation of the Department's previous Order (Attorney General Brief at 99, citing D.P.U. 19-117-B at 13; Attorney General Reply Brief at 23). The Attorney General contends that without this information, the Department cannot consider the time and cost associated with the implementation of each recommendation (Attorney General Brief at 99). Further, the Attorney General claims that the Company's representation that no incremental costs were incurred in implementing the recommendations raises a question as to whether a significant level of implementation costs occurred during the test year and, if undisclosed, would be classified as non-recurring costs and inappropriately recovered from ratepayers in the following years (Attorney General Brief at 99). Thus, the Attorney General asserts that in its final Order the Department should direct the Company to

Company ultimately determined that the detail was necessary for regulatory compliance and, therefore, did not accept the recommendation (Exh. AG 7-62, Att. at 43).

196 The Company paid FTI $850,322 in fees associated with the management audit, all of which were incurred prior to the test year and thus not included in the cost of service (Exh. AG 7-67).

identify the costs associated with implementing the FTI Report recommendations and remove the non-recurring costs occurring in the test year from the Company's proposed cost of service (Attorney General Brief at 99-100).

2. Company

National Grid argues that it implemented the FTI Report recommendations in the normal course of business with no incremental costs budgeted or used (Company Brief at 360, 362, citing Exh. AG 7-62). Additionally, National Grid contends that it was not directed to track each hour of time and the associated salary of each employee working on the implementation of each FTI Report recommendation (Company Brief at 360). According to the Company, given the nature of the implementation activities and the Department's directives, a need for such granular recordkeeping was never established (Company Brief at 360). In this regard, National Grid argues that a closer review of the FTI Report recommendations reveals that the implementation phase largely involved recurring process improvement undertakings that became part of enduring business-as-usual activities (Company Brief at 360). The Company maintains that many of the 104 implementation actions were interdependent and not distinct one-time processes that could be separately tracked (Company Brief at 360). National Grid contends that only one recommendation outlined in the FTI Report represented a non-recurring activity, the writing of a narrative explanation to report information to the Department, which the Company maintains it completed when it informed the Department of full compliance with the FTI Report requirements in December 2023 (Company Brief at 362, citing Exh. AG 7-62, Att.). Based on these considerations, National Grid asserts that the Attorney General's recommendations should be rejected and that there is no basis to disallow the costs associated with the implementation of the FTI Report (Company Brief at 360, 362).

3. Analysis and Findings

As noted above, the Department previously stated that it would evaluate National Grid's implementation of the FTI Report's recommendations during the instant base distribution rate proceeding. D.P.U. 19-117-B at 13. The evaluation was to include whether the Company implemented the recommendations in a timely, prudent, and efficient manner (including the time and cost associated with implementing each recommendation) and whether the solutions adequately addressed the deficiencies noted in the FTI Report. D.P.U. 19-117-B at 13-14.

The Department has examined each of the findings and recommendations contained in the FTI Report and their disposition in the Company's audit implementation report (Exhs. AG 1-8, Att. 8; AG 7-62, Att.). Many of the FTI Report's recommendations were addressed through a combination of new IT packages and the implementation of new procedures. For example, a number of FTI Report recommendations relative to staffing and IT were implemented through IT-based solutions, such as the Company's PeopleDataHub tool, strategic workforce planning tool, and a revised business case template that went into service during 2020 and 2021 (Exh. AG 7-62, Att. at 19, 21, 46). Other staffing-related recommendations, as well as recommendations on IT, EV, and interconnection policies, were implemented through process changes such as the creation of a strategic workforce development team, restructured employee promotions and reassignment initiatives, improved reporting systems, the creation of improved performance goals for employees engaged in EV activities, and an improved interconnection application process (Exh. AG 7-62, Att. at 23, 39, 47, 60, 61). Most of the FTI Report's recommendations related to strategic planning were addressed in conjunction with the December 2020 reorganization and the divestiture of National Grid USA's Rhode Island operations, which was prior to the test year (Exhs. AG 7-62, Att. at 4-8, 10-17; AG 7-64, at 1-3). The Company had already completed some of the recommendations by the time the final FTI Report was issued and all but one of the remaining recommendations were completed between March 2021 and October 2023, with the final recommendation completed in December 2023[197] (Exhs. NG-RRP-Rebuttal-1, at 27-29; AG 7-62 & Att.). To the extent that these implementation activities were undertaken by Company or NGSC employees, these activities were largely process-related initiatives associated with day-to-day business operations (Exhs. AG 7-62, Att.; AG 7-63). While employees may not perform those specific activities on a regular basis, the activities appear to be the kind that employees would perform in the normal course of their assigned duties. Moreover, with the exception of the last recommendation, we are persuaded that the actions taken to address the inadequacies in the FTI Report were not discrete tasks and separate time and cost tracking would have been difficult and time consuming, if even possible (Exhs. NG-RRP-Rebuttal-1, at 27-29; AG 7-62 & Att.).

Based on the foregoing analysis, the Department concludes that the Company has complied with the directives set forth in D.P.U. 19-117-B at 13-14. We find that the Company implemented the recommendations in a timely, prudent, and efficient manner. The Department is satisfied that each solution adequately addressed its corresponding recommendation. Further,

[197] This single action involved writing a narrative explanation to report information to the Department, which the Company completed in December 2023 (Exhs. NG-RRP-Rebuttal-1, at 29; AG 7-62, Att.).

with respect to the one recommendation not implemented, we find the Company's explanation to be reasonable. The Department also concludes that to the extent the Company incurred any incremental implementation costs, these costs were de minimis in comparison to the improvements in operations and productivity of the Company's management and personnel that we expect will result from the implementation of the FTI Report's recommendations. Accordingly, the Department rejects the Attorney General's recommendations.[198] The Department notes that our conclusion that the Company has complied with the directives set forth in D.P.U. 19-117-B at 13-14 relates solely to the implementation of the FTI Report recommendations and does not preclude the Department from requiring a management audit separate from this proceeding to consider further inefficiencies.

XIV. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

National Grid proposed a 7.70 percent WACC representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exh. NG-AEB-Rebuttal-16; Tr. 4, at 521). The Company's WACC is based on the following proposed elements: (1) a capital structure that consists of 47.12 percent long-term debt, 0.05 percent preferred stock, and 52.83 percent common equity; (2) a cost of long-term debt of 4.56 percent; (3) a cost of preferred stock of 4.44 percent; and (4) an ROE, or cost of equity, of 10.50 percent (Exh. NG-AEB-Rebuttal-16).

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198 While we need not substantively address the issue based on our findings above, the Attorney General's recommendation to identify incremental costs for disallowance post-Order strikes us as impractical and problematic (Attorney General Brief at 99-100; see also Exh. AG-JD-1, at 12).

The Attorney General recommends that the Department determine National Grid's WACC based on: (1) the Company's proposed capital structure, cost of long-term debt of 4.56 percent, and cost of preferred stock of 4.44 percent; and (2) an ROE of 9.00 percent (Exh. AG-JRW-Surrebuttal-1, at 39-40; Tr. 11, at 1325-1327; RR-DPU-39, Att.).[199] The Attorney General's recommendations would result in a WACC of 7.00 percent.[200]

B. Capital Structure, Cost of Debt, and Cost of Preferred Stock

1. Company Proposal

National Grid relies on a consolidated MECo and Nantucket Electric capital structure after making certain adjustments, including an adjustment related to the Company's financial restructuring plan, removal of goodwill and accumulated other comprehensive income from common equity, removal of unamortized debt issuance expenses from long-term debt, and removal of debt associated with the Nantucket Electric undersea cable projects (Exhs. NG-AEB-1, at 70; NG-AEB-Rebuttal-1, at 13-14; NG-AEB-Rebuttal-16, at 2). As of March 31, 2023, the end of the test year, MECo's recorded capital structure consisted of \$1,798,506,000 in long-term debt, \$2,259,000 in preferred stock, and \$3,146,232,000 in common equity (Exh. NG-AEB-Rebuttal-16, at 2). National Grid incorporated proposed changes to MECo's test-year-end capitalization balances (Exh. NG-AEB-1, at 70). MECo's pro forma

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199 In testimony, the Attorney General's consultant recommended an ROE of 9.375 percent based on the results of his cost of equity model results, which do not account for qualitative considerations such as management issues and quality of service (Exh. JRW-Surrebuttal-1, at 39). On brief, the Attorney General proposes an ROE of 9.00 percent (Attorney General Brief at 96). In our analysis, the Department considers the Attorney General's cost of equity model results and the ROE proposed on brief.

200 (4.70 x 0.4647) + (0.05 x 0.0444) + (9.00 x 0.5348) = 7.00.

long-term debt balance of $1,800,000,000 restores $1,494,000 in unamortized debt issuance expenses that the Company excludes from long-term debt for financial reporting purposes (Exh. NG-AEB-Rebuttal-16, at 2). MECo's pro forma common equity balance was adjusted to $2,138,086,000 to reflect the removal of $1,008,146,000 in goodwill and accumulated other comprehensive income (Exhs. NG-AEB-1, at 70; NG-AEB-Rebuttal-16, at 2). MECo also had a debt issuance of $400,000,000 and subsequent equity infusion of $250,000,000 which, when combined with the other adjustments, resulted in $2,200,000,000 in long-term debt, $2,259,000 in preferred stock, and $2,388,086,000 in common equity (Exhs. NG-AEB-1, at 70; NG-AEB-Rebuttal-1, at 13-14; NG-AEB-Rebuttal-16, at 2; RR-DPU-10, Att.).

As of March 31, 2023, Nantucket Electric's recorded capital structure consisted of $51,300,000 in long-term debt and $94,484,000 in common equity (Exh. NG-AEB-Rebuttal-16, at 2).[201] National Grid incorporated proposed changes to Nantucket Electric's test-year-end capitalization balances (Exh. NG-AEB-1, at 70). Nantucket Electric's adjusted long-term debt balance incorporates the removal of (a) $13,300,000 in debt dedicated to the financing of the first undersea cable project and (b) $38,000,000 in debt dedicated to the second undersea cable project, resulting in a zero long-term debt balance (Exh. NG-AEB-Rebuttal-16, at 2 n.C). Nantucket Electric adjusted its common equity balance to $78,748,000 to reflect the removal of $15,736,000 of goodwill and accumulated other comprehensive income (Exhs. NG-AEB-1, at 70; NG-AEB-Rebuttal-16, at 2).

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[201] Nantucket Electric does not have preferred stock.

Based on these adjustments, National Grid proposed a capital structure for the combined MECo and Nantucket Electric operations consisting of $2,200,000,000 in long-term debt, $2,259,000 in preferred stock, and $2,466,834,000 in common equity (Exh. NG-AEB-Rebuttal-16, at 2). These balances produce a capital structure consisting of 47.12 percent long-term debt, 0.05 percent preferred stock, and 52.83 percent common equity (Exhs. NG-AEB-Rebuttal-1, at 13-14; NG-AEB-Rebuttal-16, at 2). The Company proposes a rate of 4.56 percent for its long-term debt and 4.44 percent for its preferred stock (Exhs. NG-AEB-Rebuttal-1, at 13; NG-AEB-Rebuttal-16, at 1).

2. Attorney General Proposal

The Attorney General accepts the Company's proposed capital structure but recommends an ROE in the bottom half of the reasonable range to account for National Grid's lower financial risk (Exhs. AG-JRW-Testimony-1, at 4-5, 35; AG-JRW-Surrebuttal-1, at 2, 7-9, 39-40). The Attorney General also accepted the Company's long-term debt and preferred stock cost rates (Exhs. AG-JRW-Testimony-1, at 5, 111; AG-JRW-Surrebuttal-1, at 7; Tr. 11, at 1325-1327; RR-DPU-39, Att.).

3. Positions of the Parties

a. Attorney General

As noted, the Attorney General does not contest the Company's cost of debt and accepts it in her cost of capital analysis (Attorney General Brief at 54-55, Table 1).[202] The Attorney

[202] The Company revised its cost of debt in its rebuttal filing to reflect known and measurable changes (Exh. NG-AEB-Rebuttal-1, at 13). The Attorney General did not include those changes in her initial analyses but stated later in the proceeding that they are acceptable (Tr. 11, at 1325-1327; RR-DPU-39).

General, however, claims that the Company's capital structure is dissimilar to the proxy group and therefore yields an inaccurate cost of capital (Attorney General Brief at 54-55, 57).

b. Company

The Company contends that the capital structure it relies on in its cost of capital analysis is based on its actual capital structure, consistent with Department precedent (Company Brief at 400, citing D.P.U. 22-22, at 357; D.P.U. 20-120, at 381; D.P.U. 19-120, at 343; D.P.U. 18-150, at 447; D.P.U. 17-05, at 615). The Company claims that it made known and measurable post-test-year adjustments to the capital structure to reflect an incremental debt issuance of $400,000,000 at 5.87 percent and a subsequent equity injection (Company Brief at 400-401, citing Exh. NG-AEB-Rebuttal-1, at 13, 84). National Grid argues that its proposed capital structure of 47.12 percent long-term debt, 0.05 percent preferred stock, and 52.83 percent common equity is also comparable to the capital structures approved by the Department for other utilities in recent base distribution rate cases, as well as the Company in its prior rate case (Company Brief at 401, citing Exh. NG-AEB-1, at 72). In particular, the Company contends that its proposed cost of long-term debt is based on the actual cost of long-term debt, consistent with Department precedent (Company Brief at 403, citing Exhs. NG-AEB-1, at 75; NG-AEB-Rebuttal-1, at 13-14). The Company also asserts that its proposed cost of preferred stock is based on the Company's annual dividend rate of 4.44 percent for its preferred stock, consistent with Department precedent (Company Brief at 403, citing Exh. NG-AEB-1, at 75).

The Company argues that its capital structure is also comparable to the capital structure of the companies in both its own and the Attorney General's proxy groups (Company Brief at 402, citing Exhs. NG-AEB-1, at 72; NG-AEB-Rebuttal-15). Further, the Company contends that the correct way to calculate and compare capital structures between the utility companies is using market data of the holding companies (Company Brief at 402).

4. Analysis and Findings

a. Capital Structure

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. 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 comprises three components: (1) the cost of the company's long-term debt; (2) the cost of the company's preferred stock; and (3) the allowed ROE as determined by the Department.

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; D.P.U. 88-67 (Phase I) at 174; 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 which 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).

In the instant case, no party contested the Company's reversal of $1,494,000 in MECo's unamortized debt issuance expense that was credited against its long-term debt securities (Exh. NG-AEB-Rebuttal-16, at 2). The Department relies on the face value of the outstanding debt, as opposed to face value less various unamortized balances, to determine long-term debt balances for ratemaking purposes. D.P.U. 17-05, at 629. The Department has found that the appropriate ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. D.P.U. 92-78, at 91-92; D.P.U. 86-71, at 12. The Company's treatment of unamortized debt issuance costs is consistent with Department precedent. D.T.E. 03-40, at 319-324; D.P.U. 84-94, at 51-52. Therefore, the Department accepts the Company's proposed inclusion of unamortized debt issuance costs.

No party contested the Company's proposed exclusion from common equity of $1,023,882,000[203] in goodwill and accumulated other comprehensive income (Exhs. NG-AEB-1, at 70; NG-AEB-Rebuttal-16, at 2). The Department finds that the proposed removal of goodwill is consistent with Department precedent. D.P.U. 10-55, at 473-475; D.P.U. 09-39, at 338; D.P.U. 08-35, at 189; D.T.E. 05-27, at 269-272; D.T.E. 03-40, at 320-323. In the case of accumulated other comprehensive income, this balance sheet item does not represent

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[203] Of the $1,023,882,000 in goodwill and accumulated other comprehensive income, $1,008,146,000 is attributable to MECo and $15,736,000 to Nantucket Electric (Exh. NG-AEB-Rebuttal-16, at 2).

"outstanding stock" as used in G.L. c. 164, § 16. Nantucket Electric Company/Massachusetts Electric Company, D.T.E. 04-74, at 21-22 (2004). Therefore, the Department accepts the Company's proposed exclusion of accumulated other comprehensive income from common equity. D.P.U. 09-39, at 338-339.

National Grid excluded all of Nantucket Electric's outstanding long-term debt from capitalization, specifically $51,300,000 in bonds used to finance Nantucket Electric's underwater cables, because the costs of these underwater cables, including financing costs, are recovered through a separate mechanism (Exhs. NG-AEB-1, at 70; NG-AEB-Rebuttal-16, at 2).[204] Nantucket Electric Company, D.T.E./D.P.U. 06-106-A (2007). Therefore, the Department accepts the proposed elimination of Nantucket Electric's test-year-end long-term debt balance from the Company's capitalization.

Pursuant to the Department's approval in Massachusetts Electric Company and New England Power Company, D.P.U. 20-61/D.P.U. 20-62 (2020), the Company closed on the issuance of $400,000,000 in 30-year long-term debt on February 21, 2024 (Tr. 4, at 521-522, RR-DPU-10, Att.). D.P.U. 20-61, Compliance Filing (March 15, 2024). Therefore, the Department finds that the debt issuance represents a known and measurable change to test-year-end capitalization. D.P.U. 15-155, at 344-346; Aquarion Water Company of Massachusetts, Inc., D.P.U. 11-43, at 204-205 (2012); D.P.U. 07-71, at 122-123; D.T.E. 05-27, at 272; D.P.U. 84-94, at 52-53. Accordingly, the Department accepts the Company's proposed increase to MECo's long-term debt balance by $400,000,000.

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204 Nantucket Electric recovers costs associated with its underwater cables outside of base distribution rates through its Cable Facilities Surcharge provision, M.D.P.U. No. 631.

MECo also had a debt issuance of $400,000,000 and subsequent equity infusion of $250,000,000 which, when combined with the other adjustments, resulted in $2,200,000,000 in long-term debt, $2,259,000 in preferred stock, and $2,388,086,000 in common equity (Exhs. NG-AEB-1, at 70; NG-AEB-Rebuttal-1, at 13-14; Tr. 4, at 521-522).

Turning to the post-test-year capital contribution to MECo, the Department accepts known and measurable changes to a company's test-year common equity balance; however, we examine parent holding company capital contributions for potential adverse effects because capital contributions are not subject to regulatory review under G.L. c. 164, § 14. D.P.U. 23-80/D.P.U. 23-81, at 310; D.P.U. 15-155, at 345; D.P.U. 15-80/D.P.U. 15-81, at 252; D.P.U. 14-150, at 316-317; D.P.U. 10-70, at 241-242. The record demonstrates that National Grid USA's $250,000,000 capital contribution to MECo will fund operations, create a more balanced capital structure following the issuance of MECo's long-term debt on February 21, 2024, and help the Company maintain financial metrics necessary to implement its core and ESMP investments (Exh. NG-AEB-1, at 72-75). For these reasons, the Department finds that the $250,000,000 capital contribution is a known and measurable change to test-year-end capitalization, and we are satisfied that the capital contribution will not have potential adverse rate effects. Therefore, the Department accepts this proposed adjustment to the Company's capital structure.

Based on the foregoing analysis, the Department accepts the use of a long-term debt balance of $2,200,000,000, a preferred stock balance of $2,259,000, and a common equity balance of $2,466,834,000 to determine National Grid's capital structure. As shown on Schedule 5 of this Order below, the use of these balances produces a capital structure consisting of 47.12 percent long-term debt, 0.05 percent preferred stock, and 52.83 percent common equity, which we consider to be consistent with sound utility practice.

b. Cost of Debt and Preferred Stock

The Attorney General accepted the Company's recommended cost of long-term debt and preferred stock of 4.56 percent and 4.44 percent, respectively (Exhs. AG-JRW-Testimony-1, at 5, 111; AG-JRW-Surrebuttal-1, at 7; Tr. 11, at 1325-1327; RR-DPU-39). Costs associated with the issuance of long-term debt, such as issuance costs, debt discounts, and other related expenses, are necessary operating expenses and are expected to occur from time to time as long-term debt is issued by a company. D.P.U. 10-114, at 294; D.T.E. 01-56, at 99; D.P.U. 90-121, at 160. The appropriate ratemaking treatment of issuance costs is to include them in the effective cost of debt by amortizing the issuance costs over the life of the issue without providing a return on the unrecovered portion of the issuance costs. See D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161.

National Grid provided the calculations supporting the cost of its long-term debt and preferred stock (Exh. NG-AEB-Rebuttal-16, at 1). We find that the Company calculated the cost of its debt and preferred stock in a manner consistent with Department precedent. D.T.E. 01-56, at 97-100. Further, the Company's effective cost of long-term debt and preferred stock is consistent with the 5.22 percent and 4.44 percent that was approved in its last base distribution rate case proceeding. D.P.U. 18-150, at 451. Therefore, the Department accepts the Company's proposed cost of debt and preferred stock. We address the Company's proposed 10.50 percent cost of equity in the following sections.

C. Proxy Groups

1. Company Proxy Group

National Grid is a wholly owned subsidiary of National Grid USA and is not publicly traded (Exh. NG-AEB-1, at 30-31). Therefore, the Company has no public market for its stock. Accordingly, National Grid presents its ROE analysis using the capitalization and financial statistics of a proxy group of 24 publicly traded electric companies (Exhs. NG-AEB-1, at 31-33; NG-AEB-Rebuttal-1, at 9-10).[205] The Company selected its representative proxy group from a wider group of 36 companies classified as electric utilities by Value Line Investment Survey ("Value Line") (Exh. NG-AEB-1, at 31-32). From that wider group, National Grid narrowed its proxy group by selecting companies that: (1) have consistently paid quarterly dividends; (2) have been covered by at least two utility industry equity analysts; (3) have investment grade long-term issuer ratings from both Standard and Poor's ("S&P") Ratings and Moody's Ratings; (4) received at least 70 percent of their operating income from regulated electric utility operations; and (5) are not known to be part of a significant or transformative transaction (Exh. NG-AEB-1, at 31-32).[206]

2. Attorney General Proxy Group

To develop her ROE recommendation for the Company, the Attorney General evaluated the return requirements of investors on the common stock of a proxy group of 25 publicly held

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205 National Grid's proxy group initially consisted of 26 companies (Exh. NG-AEB-1, at 31-33). During the proceeding, National Grid excluded MGE Energy, Inc. because it was no longer covered by more than one analyst, and CenterPoint Energy, Inc. because it entered into a significant corporate transaction (Exh. NG-AEB-Rebuttal-1, at 9-10).

206 S&P Global Ratings and Moody's Ratings are providers of credit ratings, research, and risk analysis. D.P.U. 20-61/D.P.U. 20-62, at 5 n.7.

electric utility companies as well as the Company's proxy group (Exh. AG-JRW-Testimony-1, at 27-28).[207] The Attorney General chose companies that: (1) have at least 50 percent of revenues from regulated electric operations as reported in the SEC's Form 10-K;[208] (2) are listed as a U.S.-based electric utility by Value Line; (3) have an investment grade corporate credit and bond rating; (4) have paid a cash dividend in the past six months, with no cuts or omissions; (5) have not been involved in an acquisition of another utility, nor the target of an acquisition; and (6) have analysts' long-term earnings per share ("EPS") growth rate forecasts available from Yahoo! Inc. ("Yahoo"), S&P Capital IQ, or Zacks Investment Research, Inc. ("Zacks") (Exh. AG-JRW-Testimony-1, at 27-28).

3. Positions of the Parties

a. Attorney General

The Attorney General contends that National Grid's proxy group and her proxy group are very similar in risk based on five different metrics published by Value Line, including beta, financial strength, safety, earnings predictability, and stock price stability (Attorney General Brief at 64-65).

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207 The Attorney General noted that ALLETE, Inc. entered into a significant corporate transaction since the Attorney General's surrebuttal testimony was filed. As a result, it deviates from the Attorney General's screening criteria used to select its proxy group (Exh. AG-JRW-Testimony-1, at 27-28; Tr. 11, at 1327).

208 The Form 10-K is an annual report that publicly traded companies are required to file with the SEC. The Form 10-K provides a comprehensive summary of a company's financial position.

b. Company

The Company asserts that the objective in selecting a proxy group is developing a group of companies that are fundamentally similar with respect to operating, financial, and business risks of the Company (Company Brief at 407-408, citing D.P.U. 20-120, at 412-413; D.P.U. 08-35, at 176). National Grid contends that its proxy group consisting of 26 companies selected from Value Line has passed a set of screening criteria and is comparable to the Company (Company Brief at 408, citing Exh. NG-AEB-1, at 36-37; D.P.U. 09-30, at 307).

4. Analysis and Findings

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. 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 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 National Grid in every detail. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136. 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 National Grid versus the proxy group. D.T.E. 99-118, at 80; D.P.U. 87-59, at 68; D.P.U. 1100, at 135-136.

We find that both National Grid and the Attorney General employed a set of valid criteria to select their respective proxy groups, and they each provided sufficient information about the proxy groups to allow the Department to draw conclusions about the relative risk characteristics of the Company versus the members of the proxy groups (Exhs. NG-AEB-1, at 31-33; NG-AEB-Rebuttal-1, at 9-10; AG-JRW-Testimony-1, at 27-28). D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department considers the ROE model results of both proxy groups to determine the Company's allowed ROE.

D. Return on Equity

1. Company Proposal

a. Overview

National Grid states that because the cost of equity is not directly observable, analysts and investors gather and evaluate as much relevant data as they can reasonably analyze and use multiple analytical approaches to estimate the cost of equity (Exh. NG-AEB-1, at 34-37). To determine its proposed ROE, the Company relied on: (1) two variations of the DCF model, the constant growth DCF model and the multi-stage DCF model; (2) two variations of the capital asset pricing model ("CAPM"), the traditional CAPM and the empirical CAPM; and (3) the bond-yield risk premium model (Exhs. NG-AEB-1, at 34; NG-AEB-2 through NG-AEB-11; NG-AEB-Rebuttal-1, at 9-12; NG-AEB-Rebuttal-2 through NG-AEB-Rebuttal-11). National Grid applies these models to market and financial data developed from its proxy group as of September 30, 2023 and updated its models during the proceeding using data as of March 28, 2024 (Exhs. NG-AEB-1, at 38; NG-AEB-Rebuttal-1, at 10).[209] National Grid points out that it is important for investors, and therefore the Department, to use more than one analytical approach to estimate the Company's ROE because the cost of equity is not directly observable and the models are subject to limiting assumptions or other constraints (Exh. NG-AEB-1, at 34). Additionally, National Grid posits that it is essential to consider current and prospective capital market conditions as well as the Company's regulatory, business, and financial risk relative to the proxy group when evaluating the model results (Exhs. NG-AEB-1, at 7-8; NG-AEB-Rebuttal-1, at 12). National Grid concludes that an ROE in the range of 10.00 percent to 11.00 percent is reasonable and proposes an allowed ROE of 10.50 percent (Exhs. NG-AEB-1, at 7-8; NG-AEB-Rebuttal-1, at 12).

b. ROE Estimation Models

i. Constant Growth and Multi-Stage DCF Models

The DCF model is based on the premise that a stock's current price is equal to the present value of the expected future cash flows that investors expect to receive (Exh. NG-AEB-1, at 37). The Company employed both constant growth and multi-stage variations of the DCF model (Exhs. NG-AEB-1, at 37, 41; NG-AEB-3; NG-AEB-4; NG-AEB-Rebuttal-3; NG-AEB-Rebuttal-4).

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[209] National Grid states that its updated ROE estimates support its proposed ROE of 10.50 percent because, compared to the initial model results, the Company's updated constant growth and multi-stage DCF results increased materially, updated bond yield risk premium results are consistent, and updated CAPM and empirical CAPM results slightly decreased (Exh. NG-AEB-Rebuttal-1, at 12).

The constant growth DCF model comprises a forward-looking dividend yield component and an expected dividend growth rate into perpetuity (Exh. NG-AEB-1, at 37). The Company proposes to calculate dividend yields based on the current annualized dividend and average closing stock prices for its proxy companies over the 30-, 90-, and 180-trading day periods (Exhs. NG-AEB-1, at 38; NG-AEB-3; NG-AEB-Rebuttal-3). The Company also adjusts the dividend yields to account for periodic growth in dividends (Exhs. NG-AEB-1, at 37-39; NG-AEB-3, NG-AEB-Rebuttal-3).[210] For the expected growth rate, the Company uses projected EPS growth rates for the proxy companies from Zacks, Yahoo, and Value Line (Exhs. NG-AEB-1, at 39-41; NG-AEB-3; NG-AEB-Rebuttal-3). The Company's updated constant growth DCF model using the average growth rates from Zacks, Yahoo, and Value Line produces mean and median ROE estimates in the range of 10.11 percent to 10.32 percent (Exh. NG-AEB-Rebuttal-2).

Similar to the constant growth DCF model, the multi-stage DCF calculates the cost of equity as the present value of future cash flows, except that the growth rate is specified over three distinct stages (Exhs. NG-AEB-1, at 41; NG-AEB-4; NG-AEB-Rebuttal-4). In the first two stages, cash flows are projected dividends (Exh. NG-AEB-1, at 42). In the third stage, cash flows are equal to both dividends and the expected price at which the stock will be sold at the end of the period (i.e., the terminal price) (Exh. NG-AEB-1, at 42). In each of the three stages, the cash flow, or dividend, is the product of the projected growth rate and the expected dividend payout ratio (Exhs. NG-AEB-1, at 42; NG-AEB-4; NG-AEB-Rebuttal-4). The Company

210 The adjusted dividend yield is also referred to as the expected dividend yield (Exhs. NG-AEB-1, at 38-39; NG-AEB-3; NG-AEB-Rebuttal-3).

calculates long-term growth rates of 5.49 percent and 5.50 percent, based on the long-term real gross domestic product ("GDP")[211] from 1929 through 2022, plus an inflation rate based on the average of a compounded forward-looking rate and a consensus Blue Chip projection of the Consumer Price Index over the period 2025 through 2029 (Exhs. NG-AEB-1, at 43; NG-AEB-Rebuttal-5). National Grid's multi-stage DCF model produces mean and median ROE estimates in the range of 10.10 percent to 10.24 percent (Exh. NG-AEB-Rebuttal-2).

ii. CAPM and Empirical CAPM

The CAPM model includes three components in calculating the cost of equity: (1) an expected risk-free rate of return; (2) a market risk premium, which is the required return on the market less the risk-free rate; and (3) a beta coefficient, or beta, which is a measure of systematic risk (Exhs. NG-AEB-1, at 45-46; NG-AEB-6; NG-AEB-Rebuttal-6). The Company relies on three different measures for the risk-free rate, including a current rate based on the average 30-year U.S. Treasury bond yield for the 30 days ending March 28, 2024 (4.38 percent), a near-term rate based on the forecasted 30-year U.S. Treasury bond yield for the third quarter of 2024 through the third quarter of 2025 (4.12 percent), and a long-term rate based on the forecasted 30-year U.S. Treasury bond yield for 2025 to 2029 (4.10 percent) (Exhs. NG-AEB-1, at 46; NG-AEB-6; NG-AEB-Rebuttal-6). For the beta coefficients, the Company relies on the current beta coefficients for the proxy group companies reported by Bloomberg Professional Services and Value Line, as well as the long-term average beta coefficients for the proxy group

211 Generally, GDP is a monetary measure of the market value of all the final goods and services produced in a specific time period, often annually.

from 2013 through 2022 reported by Value Line (Exhs. NG-AEB-1, at 47; NG-AEB-8 through NG-AEB-10; NG-AEB-Rebuttal-8 through NG-AEB-Rebuttal-10).

The Company estimates a market return of 12.70 percent by applying a constant growth DCF model to the companies listed in the S&P 500 Index[212] (Exhs. NG-AEB-1, at 47-78; NG-AEB-Rebuttal-8 through NG-AEB-Rebuttal-10). The estimated 12.70 percent market return is the sum of market capitalization-weighted dividend yields and market-weighted three- to five-year expected EPS growth rate estimates from Bloomberg Professional Services (Exhs. NG-AEB-1, at 47-48; NG-AEB-8; NG-AEB-10; NG-AEB-Rebuttal-8; NG-AEB-Rebuttal-10; Tr. 4, at 530-531). National Grid's resulting market risk premiums are 8.60 percent, 8.58 percent, and 8.32 percent (Exh. NG-AEB-Rebuttal-6, at 2-10). Using these estimates for market risk premium, the Company provides nine updated CAPM results ranging from 10.65 percent to 12.08 percent that combine one of the three proposed risk-free rates with one of the three proposed beta coefficients (Exhs. NG-AEB-2; NG-AEB-6; NG-AEB-Rebuttal-2; NG-AEB-Rebuttal-6).

The Company also provides three CAPM results using a weighted market risk premium of 7.23 percent purportedly based on "the Department's methodology" (Exhs. NG-AEB-1, at 48-49; NG-AEB-10; NG-AEB-Rebuttal-10). National Grid calculates the 7.23 percent market risk premium from a weighted average of: (1) one-quarter of the expected market risk premium based on the S&P 500 Index-derived expected market return less the long-term risk-free rate, as

212 The S&P 500 Index is an American stock market index based on the market capitalization of the 500 largest U.S. companies having common stock listed on the New York Stock exchange or the NASDAQ Stock Market. D.P.U. 17-05, at 686 n.365.

discussed above; (2) one-quarter of the expected market risk premium based on an estimated market return for the Value Line universe of 1,700 companies less the long-term risk-free rate; and (3) one-half of a historical market risk premium that is the difference between the long-term market return from 1929 through 2022 and the income-only return on government bonds over the corresponding period (Exhs. NG-AEB-1, at 48-49; NG-AEB-Rebuttal-10).[213] Using the weighted market risk premium, the Company provides three updated mean CAPM results of 9.61 percent, 9.83 percent, and 10.79 percent based on the five-year projected 30-Year U.S. Treasury bond yield and each of the three proposed beta coefficients (Exhs. NG-AEB-2; NG-AEB-6; NG-AEB-Rebuttal-2; NG-AEB-Rebuttal-6).

In addition to its CAPM models, National Grid also relies on an the empirical CAPM (Exhs. NG-AEB-1, at 50-51; NG-AEB-6, at 1-10; Exh. NG-AEB-Rebuttal-1, at 10-12; NG-AEB-Rebuttal-6, at 1-10). The Company states that the empirical CAPM is intended to adjust for the CAPM's tendency to understate returns for companies with low betas, such as utilities, and overstate returns for companies with relatively high betas (Exh. NG-AEB-1, at 50). According to National Grid, the more a company's beta falls above or below 1.0, the greater the difference between that company's expected return and the results of a CAPM analysis (Exh. NG-AEB-Rebuttal-1, at 72-75). Specifically, a CAPM analysis for a company with betas below 1.0 will understate the required return, with the difference becoming greater as the beta decreases (Exh. NG-AEB-Rebuttal-1, at 74-76). Conversely, a CAPM analysis for a company

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[213] The Company uses data from Kroll and states that the historical market return from 1929 through 2022 is 12.04 percent, the risk-free rate is 4.87 percent, and that the resulting market risk premium is 7.17 percent (Exhs. NG-AEB-1, at 48-49; NG-AEB-10; NG-AEB-Rebuttal-10).

with a beta above 1.0 will overstate the required return, with the difference becoming greater as the beta increases (Exh. NG-AEB-Rebuttal-1, at 74-76). The Company contends that the empirical CAPM mitigates this drift in beta coefficients through adjustments to the risk-free rate and market risk premium (Exh. NG-AEB-1, at 50-51). Using the same data and approach as was used in its CAPM analysis relying on the market return derived from the S&P 500 Index, the Company proposes nine updated empirical CAPM results, ranging from 11.17 percent to 12.23 percent (Exhs. NG-AEB-1, at 50-51; NG-AEB-2; NG-AEB-Rebuttal-2).

iii. Bond Yield Risk Premium

National Grid states that the bond yield risk premium method for determining the cost of equity recognizes that common equity capital is riskier than debt from an investor's standpoint and that investors require higher returns on stocks than on bonds to compensate for the additional risk (Exh. NG-AEB-1, at 52). The Company calculates the risk premium based on a regression analysis of authorized ROEs for electric utilities from the first quarter of 1980 through the first quarter of 2024 and the yield on 30-year treasury bonds over the same time period (Exhs. NG-AEB-1, at 52-54; NG-AEB-Rebuttal-11). The Company then applies its risk premium regression analysis to three different 30-year U.S. Treasury yields: (1) a current yield of 4.38 percent, (2) a near-term projected yield of 4.12 percent, and (3) a long-term projected yield of 4.10 percent (Exh. NG-AEB-Rebuttal-11). Based on this analysis, the Company's bond yield risk premium model produces ROE estimates of 10.46 percent, 10.31 percent, and 10.30 percent, respectively (Exhs. NG-AEB-Rebuttal-1, at 12; NG-AEB-Rebuttal-11).

c. Reasonable Range and Proposed ROE

National Grid recommends that the Department consider current and prospective market conditions and the Company's regulatory and financial risk relative to the proxy group when analyzing the model results (Exhs. NG-AEB-1, at 13-29, 55-69; NG-AEB-Rebuttal-1, at 84-93, 95-103). National Grid states that these factors support the Company's proposed reasonable range of 10.00 percent to 11.00 percent and ROE of 10.50 percent (Exhs. NG-AEB-1, at 7-8, 79; NG-AEB-Rebuttal-1, at 6-9, 96-102).

Regarding market conditions, National Grid states that the year-over-year inflation rate has increased significantly over the past year and that it will likely remain above the Federal Reserve's target level of 2.0 percent (Exh. NG-AEB-1, at 16). National Grid also reports that interest rates and inflation have increased since its last base distribution rate proceeding, which indicates that the cost of equity has increased since the Department authorized an ROE of 9.60 percent for the Company (Exh. NG-AEB-1, at 20-21). Therefore, National Grid urges the Department to consider the impact of persistently high inflation and elevated interest rates when evaluating the model results, particularly because cost of equity estimates are based in whole or in part on historical or current market conditions and, according to the Company, expected market conditions indicate that the cost of equity will increase during the period that the Company's rates will be in effect (Exh. NG-AEB-1, at 15-16, 19-20).

Additionally, National Grid states that the Department must consider the Company's regulatory and business risks to decide where the Company's cost of equity falls within the range of model results (Exh. NG-AEB-1, at 11, 55-56). National Grid explains that the heightened level of capital investment needed to meet its core and ESMP programs may increase its risk profile because of the risk of under-recovery or delayed recovery and an inadequate return, both of which would put downward pressure on key credit metrics (Exh. NG-AEB-1, at 57-60). Further, the Company states that 69 percent of the utility operating companies owned by the proxy group entities employ capital tracking mechanisms and, therefore, the Company's proposed CPI plan does not make National Grid less risky than its peers (Exhs. NG-AEB-1, at 57-61; NG-AEB-Rebuttal-1, at 98-99). National Grid also states that the absence of a capital tracking mechanism would make the Company more risky than its peers, particularly because of the relatively large size of its expected capital expenditures (Exhs. NG-AEB-1, at 57-59, 61; NG-AEB-Rebuttal-1, at 98).

2. Attorney General Proposal

a. Overview

The Attorney General recommends that the Department authorize an ROE of 9.00 percent (Attorney General Brief at 96, citing Exh. AG-JRW-Testimony-1, at 27). To determine her proposed ROE, the Attorney General considers the results of her consultant's constant growth DCF and the CAPM models (Exhs. AG-JRW-Testimony-1, at 43-44; AG-JRW-5; AG-JRW-6; AG-JRW-Surrebuttal-10; AG-JRW-Surrebuttal-11). The Attorney General's evaluation of her cost of equity model results includes consideration of market conditions, national trends in authorized ROEs, the relative low investment risk of the utility industry, and the investment risk implications of National Grid's higher credit rating and higher common equity ratio relative to the proxy groups (Exh. AG-JRW-Testimony-1, at 6, 16-18, 22-27). Ultimately, the Attorney General recommends that the Department authorize an ROE at the lowest end of the range of reasonableness suggested in her consultant's initial testimony, i.e., 9.00 percent, because of National Grid's non-compliance with the Department's directives related to a management audit ordered in 2019 and National Grid USA's divestiture of its Rhode Island businesses (Attorney General Brief at 96, citing D.P.U. 18-150, at 498-503; Exhs. AG-JD-1, at 16-17; AG-JD-Surrebuttal-1, at 7-9).

b. ROE Estimation Models

i. DCF Model

The Attorney General relies on the constant growth DCF model, stating that the public utility is in the steady state (Exh. AG-JRW-Testimony-1, at 43-48). Like the Company, the Attorney General calculates dividend yields for each proxy group using the current annual dividend and 30-day, 90-day, and 180-day average stock prices (Exhs. AG-JRW-Testimony-1, at 48-49; AG-JRW-5, at 2). In her surrebuttal testimony, the Attorney General provides an updated dividend yield of 4.31 percent for both proxy groups (Exhs. AG-JRW-Surrebuttal-1, at 34; JRW-10, at 1).

Unlike National Grid, however, the Attorney General considers several measures of projected long-term growth rather than relying exclusively on projected EPS growth rates (Exh. AG-JRW-Testimony-1, at 50-52, 59-60). She derives her long-term growth rate from the range of projected growth rates of EPS, dividends per share ("DPS"), and book value per share ("BVPS") provided by Value Line and the EPS growth forecasts of Wall Street analysts provided by Yahoo, Zacks, and S&P Capital IQ (Exhs. AG-JRW-Testimony-1, at 50, 57-58; AG-JRW-5, at 3-6; AG-JRW-Surrebuttal-1, at 14-15). In addition, the Attorney General considers an internal growth rate, or sustainable growth rate, which she measures from Value Line's projected retention rate and earned returns on common equity (Exhs. AG-JRW-Testimony-1, at 50, 58;

AG-JRW-5, at 4, 6; JRW-10, at 4, 6). The Attorney General gives primary weight to projected EPS growth rates but recognizes the presence of upward bias in EPS forecasts and uses a growth rate of 5.40 percent for her proxy group and 5.45 percent for the Company's proxy group (Exhs. AG-JRW-Testimony-1, at 53-60; AG-JRW-Surrebuttal-1, at 34-36; JRW-10, at 6).

After rounding her results to the nearest 0.05 percent, the Attorney General's initial DCF results were 9.65 percent for her proxy group and 9.45 percent for the Company's proxy group (Exh. AG-JRW-Testimony-1, at 61). The Attorney General's updated DCF results, also rounded, are 9.70 percent for her proxy group and 9.75 percent for the Company's proxy group (Exhs. AG-JRW-Surrebuttal-1, at 36-37 n.39; JRW-10, at 1). Prior to rounding, the initial computed cost of equity values for the Attorney General's DCF model are 9.66 percent and 9.46 percent for her proxy group and the Company's proxy group, respectively (Exh. AG-JRW-5, at 1). In her surrebuttal filings, the computed cost of equity values prior to rounding are 9.71 and 9.76 percent for her proxy group and the Company's proxy group, respectively (Exh. JRW-10, at 1).

ii. CAPM Model

The Attorney General's CAPM analysis includes the same components as the Company's CAPM analysis: (1) a risk-free rate of return; (2) a market risk premium; and (3) beta coefficients of the companies in the proxy groups (Exhs. AG-JRW-Testimony-1, at 61-62; AG-JRW-6, at 1; JRW-11, at 1). The Attorney General uses the 30-year U.S. Treasury bond yield of 4.75 percent as the risk-free rate or return, and beta coefficients of 0.80 for her proxy group and 0.81 for the Company's proxy group (Exh. AG-JRW-Surrebuttal-1, at 38).

The Attorney General uses a market risk premium of 5.25 percent based on her review of various market risk premium studies and surveys of financial professionals (Exhs. AG-JRW-Testimony-1, at 77; AG-JRW-6, at 4-7; AG-JRW-Surrebuttal-1, at 37-38; Tr. 4, at 1353-1356). The beta coefficients she employed, 0.80 for her proxy group and 0.81 for the Company's proxy group, are calculated using the average of: (1) the Blume-adjusted beta coefficients of the proxy group firms provided by Value Line, and (2) the unadjusted betas from S&P Capital IQ, which the Attorney General adjusts herself using the Blume-adjustment procedure (Exhs. AG-JRW-Testimony-1, at 67-68; AG-JRW-6, at 3; AG-JRW-Surrebuttal-1, at 38; JRW-11, at 2).

The Attorney General's initial CAPM results, rounded to the nearest 0.05 percent, were 8.60 percent for both proxy groups (Exh. AG-JRW-Testimony-1, at 78). The Attorney General's updated CAPM results, also rounded, are 8.95 percent for her proxy group and 9.00 percent for the Company's proxy group (Exhs. AG-JRW-Surrebuttal-1, at 38; JRW-11, at 1). Prior to rounding, the initial computed cost of equity values for the Attorney General's CAPM model are 8.61 percent for both proxy groups (Exh. AG-JRW-6, at 1). In her surrebuttal filings, the computed cost of equity values prior to rounding are 8.97 percent and 8.98 percent for her proxy group and the Company's proxy group, respectively (Exh. JRW-11, at 1).

c. <u>Reasonable Range and Proposed ROE</u>

As mentioned above, the Attorney General's recommended ROE considers market conditions, national trends in authorized ROEs, the relative low investment risk of the utility industry, and the investment risk implications of National Grid's higher credit rating and higher common equity ratio relative to the proxy groups (Exh. AG-JRW-Testimony-1, at 6, 16-18, 22-27). Regarding market conditions, the Attorney General states that the yields on U.S. Treasury inflation-protected securities suggest longer-term inflation expectations are 2.25 percent and that investors expect interest rates to decrease soon (Exh. AG-JRW-Testimony-1, at 16-18). Additionally, she states that an inverted yield curve suggests that the prospect of a recession is likely, which would lead to lower interest rates and, thus, the cost of equity (Exh. AG-JRW-Testimony-1, at 17-19).

Regarding trends in authorized ROEs, the Attorney General states that authorized ROEs have not declined in line with capital costs over the past four decades and, subsequently, past authorized ROEs have overstated the actual cost of equity (Exh. AG-JRW-Testimony-1, at 19, 22-23). The Attorney General also adds that delivery-only companies like National Grid are lower risk compared to vertically integrated electric utilities, which are included in the nation-wide average for authorized ROEs (Exh. AG-JRW-Testimony-1, at 20-21). She points out that vertically integrated utilities have authorized ROEs that are, on average, 30 to 50 basis points higher than the authorized ROEs of delivery-only utilities (Exh. AG-JRW-Testimony-1, at 20-21).

The Attorney General also recommends that the Department's authorized ROE account for National Grid's investment risk (Exh. AG-JRW-Testimony-1, at 79). First, the Attorney General contends that the Company has less financial risk relative to the proxy group due to its higher common equity ratio (Exh. AG-JRW-Testimony-1, at 35, 79). Second, she asserts that National Grid also has less investment risk relative to the proxy group because its parent company had its credit rating downgraded to BBB+ due to reasons unrelated to its U.S.-based operations and, therefore, its credit rating of A- prior to the downgrade should be used as the

Company's credit rating (Exh. AG-JRW-Testimony-1, at 29, 79). Third, the Attorney General states that the Company should receive a lower ROE in general since the utility industry is lower risk as measured by beta (Exh. AG-JRW-Testimony-1, at 41-42, 79).

3. Positions of the Parties

a. Attorney General

i. ROE Estimation Models

(A) Constant Growth and Multi-stage DCF Models

The Attorney General claims that there are two main errors with National Grid's DCF analysis (Attorney General Brief at 67, citing Exh. AG-JRW-Testimony-1, at 82-88). First, she argues that the Company relies exclusively on the upwardly biased EPS growth forecasts of financial market analysts (Attorney General Brief at 67, citing Exh. AG-JRW-Testimony-1, at 80-82; Attorney General Reply Brief at 20-22). Furthermore, she asserts that the few errors in her consultant's study demonstrating the bias in forecasted EPS growth rates do not change the results of the study given the amount of raw data, and that the Company provided no evidence that the identified errors impact the results (Attorney General Reply Brief at 22, citing Exh. AG-JRW-Surrebuttal-1, at 7). Second, the Attorney General argues that the terminal growth rate of 5.49 percent[214] employed in the Company's multi-stage DCF model overstates projected GDP growth by about 100 basis points (Attorney General Brief at 70-71, citing Exh. AG-JRW-Testimony-1, at 86-90).

214 The Attorney General references the 5.49 percent growth rate provided in National Grid's initial filing rather than the 5.50 percent growth rate provided in National Grid's updated models (Attorney General Brief at 70-71).

(B) CAPM and Empirical CAPM

The Attorney General argues that the Company's CAPM analysis inflates the cost of equity because of its reliance on the empirical CAPM and an excessively high market risk premium (Attorney General Brief at 58, citing Exh. AG-JRW-Testimony-1, at 8-9). The Attorney General contends that the empirical CAPM is nothing more than an ad hoc version of the CAPM that has not been theoretically or empirically validated in refereed journals (Attorney General Brief at 77, citing Exh. AG-JRW-Testimony-1, at 90). The Attorney General adds that adjusted betas such as those from Value Line address the empirical issues with the CAPM and renders the empirical CAPM redundant (Attorney General Brief at 77, citing Exh. AG-JRW-Testimony-1, at 90).

Regarding the market risk premium, the Attorney General claims that National Grid's estimated market risk premium greatly exceeds the market risk premiums found in historical stock and bond analyses, ex-ante studies by leading academic scholars, and the surveys of market analysts and financial professionals (Attorney General Brief at 78-79). The Attorney General argues that the expected market return estimated by the Company using the DCF model with S&P 500 Index data from Bloomberg Professional Services is excessive and unrealistic (Attorney General Brief at 78, citing Exh. AG-JRW-Testimony-1, at 92-98).

According to the Attorney General, the underlying flaw in the Company's market risk premium calculation is the reliance on three- to five-year EPS growth rates to reflect long-term expectations of EPS growth (Attorney General Brief at 80, citing Exh. AG-JRW-Testimony-1, at 96). She argues that the three- to five-year projections are overly optimistic and upwardly biased, inflating the indicated cost of equity by about 300 basis points (Attorney General Brief at 80).

The Attorney General also asserts that historic EPS and GDP growth rates have been in the six percent to seven percent range, and recent trends in GDP growth and projections of GDP growth indicate lower GDP and earnings growth in the future (Attorney General Brief at 84, citing Exh. AG-JRW-Testimony-1, at 96-98, 101-103). The Attorney General contends that this analysis shows that the Company's long-term EPS growth rate of 11.01 percent, which it uses to compute an expected market return, is overstated and unrealistic (Attorney General Brief at 85). The Attorney General avers that, in the long term, earnings cannot grow faster than the economy and that near-term projections of EPS growth are not sustainable in the long-term (Attorney General Brief at 85-86).

(C) Bond Yield Risk Premium

The Attorney General claims that five errors in the Company's bond yield risk premium model result in an overstatement of the cost of equity (Attorney General Brief at 86-87). First, the Attorney General contends that regulatory commissions factor in other utility- and rate case-specific information in their decisions that may not be relevant to the Company (Attorney General Brief at 87, citing Exh. AG-JRW-Testimony-1, at 109). Second, the Attorney General maintains that the Company's method produces an inflated measure of the risk premium because projected U.S. Treasury yields are always forecasted to increase (Attorney General Brief at 87, citing Exh. AG-JRW-Testimony-1, at 109). Third, she asserts that utility stocks have been selling at market-to-book ratios well in excess of 1.0 for many years, which she contends implies that authorized returns have exceeded the required return (Attorney General Brief at 87, citing

Exh. AG-JRW-Testimony-1, at 110). Fourth, the Attorney General asserts that the authorized ROEs used as an input include the ROEs of higher risk, vertically-integrated electric utilities (Attorney General Brief at 87, citing Exh. AG-JRW-Testimony-1, at 110). Finally, the Attorney General contends that authorized ROEs have historically overstated the actual cost of equity capital (Attorney General Brief at 87, citing Exh. AG-JRW-Testimony-1, at 110).

ii. Market Conditions and Trends in Authorized ROEs

The Attorney General argues that a strong economy and high inflation resulted in an increase in 30-year U.S. Treasury yields in 2023 and 2024, peaking at over 5.0 percent in the fall of 2023 and declining to around 4.40 percent at the time of this proceeding (Attorney General Brief at 88, citing Exh. AG-JRW-Testimony-1, at 12-13). The Attorney General contends that the expected inflation rates over the next five, ten, and 30 years are about 2.25 percent (Attorney General Brief at 89, citing Exh. AG-JRW-Testimony-1, at 14-19). Further, she argues that in the last five years, authorized ROEs in the Commonwealth for EDCs and LDCs did not decline in line with interest rates and capital costs (Attorney General Brief at 91, citing Exh. AG-JRW-Testimony-1, at 23-24). The Attorney General claims that declining inflation and her consultant's study examining the relationship between authorized ROEs for utilities and interest rates over the last five years support her recommended ROE (Attorney General Brief at 92, citing Exh. AG-JRW-Testimony-1, at 22-27).

iii. Investment Risk

The Attorney General argues that the Company has less financial risk and a lower cost of capital compared to the proxy groups because the Company's debt to equity ratio is lower (Attorney General Brief at 54-55, 57). She asserts that the Department should account for

National Grid's lower financial risk by allowing an ROE on the lower end of the reasonable range (Attorney General Brief at 96).

The Attorney General also argues that the Company is less risky than the two proxy groups, despite the comparable credit ratings, because the Company's credit rating downgrade on March 3, 2021 was due to rate regulation issues with National Grid plc that have nothing to do with National Grid's U.S. operations (Attorney General Brief at 64). In addition, she maintains that Value Line's risk rating of the two proxy groups suggest that electric utility companies are very low risk (Attorney General Brief at 64-65).

iv. Management Decisions

As mentioned above, the Attorney General argues the Department should factor in the Company's failure to follow the Department's past directives (Attorney General Brief at 96; Attorney General Reply Brief at 23). She maintains that National Grid failed to track costs and provide information regarding the prudency of a management audit that the Department ordered in 2019 (Attorney General Brief at 96). Furthermore, she asserts that National Grid has failed to provide the information necessary to determine whether the Company mitigated the costs associated with the divestiture of National Grid USA's Rhode Island businesses in compliance with the Department's directives (Attorney General Brief at 96). The Attorney General contends that if these compliance failures go unchecked the Company may over-inflate its cost of service by including more than the prudent and reasonable costs associated with operating an efficient company (Attorney General Reply brief at 23). Therefore, the Attorney General urges the Department to authorize an ROE of 9.00 percent, which she contends is the lowest end of the range of reasonableness supported by her consultant's analysis (Attorney General Brief at 96, citing Exh. AG-JRW-Testimony-1, at 27).

b. Acadia Center

Acadia Center argues the Department should approve an ROE not exceeding 9.375 percent, which is comparable to other authorized ROEs in New England (Acadia Center Brief at 13-15). Acadia Center further argues that the 10.50 percent ROE requested by the Company is higher than the ROEs requested by comparable utility companies (Acadia Center Brief at 14).

c. Company

i. ROE Estimation Models

(A) Constant Growth and Multi-Stage DCF Models

National Grid maintains that EPS growth rates are appropriate as the sole input for the DCF model because: (1) earnings are the fundamental determinant of a company's ability to pay dividends; (2) there is significant academic research demonstrating that EPS growth rates are most relevant in stock price valuation; and (3) investment analysts report predominant reliance on EPS growth projections (Company Brief at 409, citing Exhs. NG-AEB-Rebuttal-1, at 31; DPU 15-8). The Company further claims that EPS growth rates are available on a consensus basis, and that the Department has previously accepted DCF results that utilize EPS growth rates (Company Brief at 409, 422-423, citing Tr. 4, at 558; Tr. 11, at 1331; D.P.U. 22-22, at 386; D.P.U. 18-150, at 472; D.P.U. 19-120, at 373). Moreover, National Grid alleges that yields on long-term government bonds currently exceed the dividend yields of utilities counter to their historical relationship and, subsequently, utility stock prices may decline as utility dividend yields normalize towards the historical average (Company Brief at 410, citing Exh. NG-AEB-1, at 25-26). National Grid argues that if utility dividend yields normalize, as expected, the DCF model results provided in this proceeding likely understate the Company's cost of equity (Company Brief at 410, citing Exh. NG-AEB-1, at 25-26).

National Grid also defends its use of a forecasted 5.49 percent growth rate for the third stage of its multi-stage DCF model (Company Brief at 425). The Company asserts that a growth rate of 5.49 percent is only nine basis points higher than the growth rate ultimately used by the Attorney General in her constant growth DCF analysis (Company Brief at 425, citing Exhs. NG-AEB-Rebuttal-1, at 56; AG-JRW-Surrebuttal-1, at 37). Moreover, the Company contends that a growth rate of 5.49 percent is well within the range of growth rates deemed appropriate for use by the Attorney General in developing her constant growth DCF model (Company Brief at 425-426, citing Exhs. NG-AEB-Rebuttal-1, at 57; AG-JRW-Testimony-1, at 59).

National Grid also argues that the Department should reject the Attorney General's constant growth DCF calculation based on two main flaws (Company Brief at 420). First, the Company claims that the Attorney General's approach is subjective, not replicable, and results oriented (Company Brief at 421, citing Exh. NG-AEB-Rebuttal-1, at 42-46). Second, National Grid maintains that the Attorney General's DCF recommendation improperly relies on DPS, BVPS, and sustainable growth rates (Company Brief at 421, citing Exh. NG-AEB-Rebuttal-1, at 31-32). The Company contends that the DCF model should not include DPS and BVPS growth rates because they are prone to fluctuating and are merely derivatives of earnings growth (Company Brief at 421-422, citing Exh. NG-AEB-Rebuttal-1, at 31-39). Moreover, the

Company argues that DPS and BVPS growth rates do not accurately reflect all of the growth made by a company and that DPS and BVPS growth rates vary due to management decisions (Company Brief at 422, citing Exh. NG-AEB-Rebuttal-1, at 39). The Company avers that it is unreasonable to use a company's projected DPS growth rates if it is not equivalent to the company's projected EPS growth rate because one of the assumptions of the constant growth DCF model is that the growth rate be constant in perpetuity and dividend growth can only be sustained by earnings growth (Company Brief at 422, citing Exh. NG-AEB-Rebuttal-1, at 32-33). The Company also asserts that the Attorney General's sustainable growth rates unreasonably lower the estimated cost of equity and should not be relied upon because the relationship between earnings growth rate and retention payout ratios is negative, not positive as the Attorney General claims (Company Brief at 422, citing Exh. NG-AEB-Rebuttal-1, at 40).

In response to the Attorney General's claim that EPS growth rates are overly-optimistic, National Grid asserts that the Global Analyst Research Settlement[215] in 2003 helped neutralize bias among financial analysts and most of the studies cited by the Attorney General predate the Global Analyst Research Settlement (Company Brief at 423, citing Exh. NG-AEB-Rebuttal-1, at 47, 53). The Company also claims that there are errors and inconsistencies in the study performed by the Attorney General's consultant, which invalidate his findings (Company Brief at 424, citing Exh. NG-AEB-Rebuttal-1, at 46). Ultimately, the Company argues that it is

215 The Global Analyst Research Settlement resolved an investigation by the SEC and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts (Exh. NG-AEB-Rebuttal-1, at 47, 50).

irrelevant whether EPS forecasts are biased because they are relied upon by investors to set stock prices (Company Brief at 425, citing Exh. NG-AEB-Rebuttal-1, at 88-89).

(B) CAPM and Empirical CAPM

National Grid rejects the Attorney General's criticism of its market risk premium (Company Brief at 427). The Company claims that the realized total market return was at least 12.90 percent for 52 percent of the last 97 years (Company Brief at 427, citing Exhs. NG-AEB-1, at 49; NG-AEB-Rebuttal-1, at 64).[216] The Company also argues that it's CAPM is consistent with Department precedent (Company Brief at 418-419, citing Exhs. NG-AEB-Rebuttal-9; NG-AEB-Rebuttal-10). The Company also maintains that its approach to determine the market risk premium is similar to the approach approved by FERC (Company Brief at 427, citing Exh. NG-AEB-Rebuttal-1, at 64).

National Grid contends that there are academic studies showing that the CAPM may understate or overstate returns for companies with betas less than or greater than 1.0, respectively (Company Brief at 427-428, citing Exh. NG-AEB-Rebuttal-1, at 73-74). Further, the Company argues that there are studies showing that the empirical CAPM outperforms the traditional CAPM at predicting the observed risk premium for various utility subgroups (Company Brief at 428, citing Exh. NG-AEB-Rebuttal-1, at 76). Finally, the Company claims that various other regulatory commissions have accepted the empirical CAPM (Company Brief at 428, citing Exh. NG-AEB-Rebuttal-1, at 77-78).

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216 The Company's market risk premium based on the S&P 500 Index was 12.90 percent in its initial filing and updated to 12.70 percent with the Company's rebuttal testimony (Exhs. NG-AEB-1, at 49; NG-AEB-Rebuttal-1, at 64).

National Grid further claims that the Department must reject the Attorney General's CAPM model because of the market risk premium used (Company Brief at 426, citing Exh. NG-AEB-Rebuttal-1, at 61). The Company asserts that the current market risk premium should be higher than the historical average of 7.17 percent based on the inverse relationship between interest rates and the market risk premium (Company Brief at 426, citing Exh. NG-AEB-Rebuttal-1, at 61-62). In addition, the Company avers that the Department previously has determined that the surveys reviewed by the Attorney General are unreliable (Company Brief at 427, citing D.P.U. 19-120, at 385; D.P.U. 18-150, at 484). The Company also maintains that the Attorney General's CAPM results understate the cost of equity because of its reliance on the geometric mean returns, as opposed to arithmetic mean returns (Company Brief at 419, citing D.P.U. 23-80/D.P.U. 23-81, at 356-357; NG-AEB-Rebuttal-1, at 69-70).

(C) Bond Yield Risk Premium

The Company maintains that the bond yield risk premium model is a widely referenced method for estimating the cost of equity (Company Brief at 413-414). Further, National Grid contends that academic literature and market evidence support the bond yield risk premium model (Company Brief at 413-414, citing Exh. NG-AEB-1, at 52-53). The Company also argues that its bond yield risk premium model is relevant as authorized ROEs of other utilities are one of the factors that investors consider in their decision-making (Company Brief at 414, citing Exh. NG-AEB-1, at 53).

ii. Market Conditions and Investment Risk

National Grid maintains that it is critical for the Company's authorized ROE to allow it to attract capital under whichever economic conditions prevail (Company Brief at 405). The

Company contends that inflation expectations over the next five years of about 2.25 percent remain above the Federal Reserve's two-percent target, which demonstrates that inflation, and as a result interest rates, will remain elevated for the next several years (Company Brief at 430-431, citing Attorney General Brief at 56; Exh. NG-AEB-Rebuttal-1, at 20-23, 69). National Grid claims that the ROE authorized in this proceeding should be higher than the ROE authorized in its last base distribution rate case because interest rates have significantly increased over that time period (Company Brief at 431, citing Exh. AG-JRW-1, at 13).

With respect to investment risk, National Grid claims that its planned level of capital expenditures far exceeds that of the companies in the proxy group and, therefore, adversely affects the Company's risk profile (Company Brief at 415, citing Exh. NG-AEB-1, at 57-60). In addition, National Grid asserts that the PBR-O mechanism and ISRE mechanism do not lower the Company's risk relative to the companies in the proxy group (Company Brief at 415-416, citing Exh. NG-AEB-1, at 57-61). Further, the Company alleges that it exists in a regulatory environment that is comparable but slightly less supportive than its peers (Company Brief at 416, citing Exh. NG-AEB-1, at 68-69). The Company emphasizes that the Department should select an ROE that allows it to obtain financing of its investments at a cost consistent with or more favorable than other utilities (Company Brief at 419-420).

iii. Management Decisions

National Grid argues that the Attorney General's allegations that the Company did not track and report on costs associated with a management audit and did not provide information as to the mitigation of costs associated with the divestiture of Rhode Island operations are incorrect (Company Reply Brief at 54). Further, the Company contends that an ROE of 9.00 percent is outside of the appropriate ROE range suggested by the Attorney General in her surrebuttal testimony and, therefore, should be rejected by the Department (Company Reply Brief at 55).

4. Analysis and Findings

a. Introduction

When setting a reasonable range of ROEs and then determining the allowed ROE, the Department is guided by the standard set forth in Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944) ("Hope"); Bluefield at 692-693. The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. Bluefield at 692-693; Hope at 603, 605. "What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts." Bluefield at 692.

The use of empirical analyses in this context is not an exact science. D.P.U. 17-170, at 305; D.P.U. 15-155, at 377; see also Southern Bell Telephone and Telegraph Company v. Louisiana Public Utility Commission, 239 La. 175, 225 (1960) (ascertainment of a fair return in a given case is a matter incapable of exact mathematical demonstration); United Railways & Electric Company of Baltimore v. West, 280 U.S. 234, 250 (1930) (what will constitute a fair return is not capable of exact mathematical demonstration). Conducting a model-based ROE analysis requires the analyst to make several subjective judgments. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

While the results of analytical models are useful, the Department must ultimately use our own judgment of the evidence to determine an appropriate ROE. We must apply the Department's considerable judgment and expertise to the record evidence and arguments to determine the appropriate use of the empirical results. Our task is not a mechanical or model-driven exercise. D.P.U. 08-35, at 219-220; D.P.U. 07-71, at 139; D.T.E. 01-56, at 118; D.P.U. 18731, at 59; see also Boston Edison, 375 Mass. 1, 15 ("experience has shown that, in making a determination as elusive as estimating the cost of equity capital, 'mathematical formulas and rules of thumb are obsolete,'" citing A.J.G. Priest, Principles of Public Utility Regulation (196) (1969)).[217]

b. ROE Estimation Models

i. Constant Growth DCF Model

The Company and the Attorney General both rely on the constant growth DCF model, a valuation method commonly used in the field of finance, which holds that the present value of an asset is equal to the discounted value of its expected future cash flows, discounted by the

217 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.

investor at a required rate of return (Exhs. NG-AEB-1, at 37; AG-JRW-Testimony-1, at 44-45). This required rate of return reflects both the time value of money (i.e., the concept that an amount of money received in the future is not worth as much as an equal amount received today) and the perceived riskiness of the expected future cash flows (Exh. AG-JRW-Testimony-1, at 43, 46). The parties disagree on the appropriate input for the long-term growth rate in the model, and they propose either: (1) the proxy companies' projected three-to-five-year EPS growth rates; or (2) a composite growth rate based on the proxy companies' projected EPS, DPS, BVPS, and sustainable growth rates (Exhs. NG-AEB-1, at 39; AG-JRW-Testimony-1, at 50, 59-60).

The starting point of the Department's analysis on the appropriate growth rate for the DCF model is the theoretical assumptions underlying the model itself. Dividends, rather than earnings, constitute the source of value in the DCF model because investors' returns ultimately result from current as well as future dividends (Exhs. NG-AEB-1, at 37; AG-JRW-Testimony-1, at 44-45; Tr. 4, at 523). The Company and the Attorney General agree that the constant growth DCF model is appropriate for utility companies because utility companies are in the mature stage of the growth cycle and the constant growth DCF model assumes that the firm subject to valuation analysis is in the mature stage of its business life cycle with dividends and earnings growing at the same rate in perpetuity (Exhs. NG-AEB-1, at 38; AG-JRW-Testimony-1, at 45-47; DPU 3-8; Tr. 4, at 535; Tr. 11, at 1332).

In addition to the theoretical assumptions underlying the model, the Department has found that companies in the mature stage of their business life cycle pursue dividend policies that align dividend growth with a company's internal long-term growth expectations. D.P.U. 23-80/D.P.U. 23-81, at 349. In other words, mature companies like the utilities in the proxy groups do not significantly increase or cut dividends in response to periods of unusually high or low earnings because of the signals that would send to the market.

D.P.U. 23-80/D.P.U. 23-81, at 349. The Department also has found that unlike DPS growth rates that companies keep stable over time, EPS growth rates reflect current firm-specific and economic conditions that may not reflect reasonable long-term growth expectations. D.P.U. 23-80/D.P.U. 23-81, at 349-350. Accordingly, the Department has found that the use of DPS growth rates in the DCF model is consistent with the theoretical assumptions of the DCF model and an important measure of long-term growth. D.P.U. 23-80/D.P.U. 23-81, at 350.

The record in this proceeding further supports our prior finding that projected DPS growth rates for mature companies like utilities are more stable than projected EPS growth rates and, therefore, are an important consideration for the long-term growth component of the DCF model. The Company's analysis shows that the average change of the EPS growth rates for the proxy companies is higher than the average change for DPS growth rates over time (Exh. DPU 27-4, Att. 2; Tr. 4, at 526-527). Specifically, the rate of change is 6.84 percent for EPS growth rates compared to 5.67 percent for DPS growth rates, meaning EPS growth rates are more volatile (Exh. DPU 27-4, Att. 2; Tr. 4, at 527-528). In addition, the Department observes that the range for EPS growth rates (-8.33 percent to 46.00 percent) is notably larger than the range for DPS growth rates (3.89 percent to 9.38 percent) (Exh. DPU 27-4, Att. 2, at 2-4).

Furthermore, we find that National Grid's justifications for its exclusive reliance on EPS growth rates are unpersuasive. The record demonstrates that investors value the information provided by projected EPS growth rates (Exhs. NG-AEB-Rebuttal-1, at 41-42; DPU 15-8; Tr. 11, at 1335). Nonetheless, we find that National Grid's argument that it is reasonable to rely only on EPS growth rates because dividends are paid out of earnings and subject to management decisions is inconsistent with the Company's testimony that "when faced with the task of estimating the cost of equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed" (Exhs. NG-AEB-1, at 34; NG-AEB-Rebuttal-1, at 31-32, 39; DPU 27-2(b); Tr. 4, at 542). Further, since dividends are the source of value to an investor in the DCF models, we find that National Grid's proposition that a prudent investor would not consider information about changes to DPS growth expectations, such as the examples cited by the Company of retaining earnings for capital investment or in response to economic conditions, is unreasonable (Exhs. NG-AEB-Rebuttal-1, at 31-32; DPU 27-2(b)). The Company has not provided any persuasive evidence in this case that a prudent investor would ignore DPS growth expectations in making investment decisions.

Additionally, we have reviewed the so-called "extensive academic research" provided by National Grid to support its claim that EPS growth rates are most relevant in stock price valuation (Exhs. DPU 15-8; DPU 27-2 & Atts.). The excerpts provided by National Grid do not support the proposition that EPS growth rates are more relevant, and none of the excerpts provided by the Company states that DPS growth rates are irrelevant (Exhs. DPU 15-8; DPU 27-2 & Atts.).

The Company also reasons that because DPS growth rates are available from only one source and EPS growth rates are available on a consensus basis from multiple analysts and multiple sources, then EPS growth rates must be the most relevant growth rate (Tr. 4, at 557-558). We are not persuaded that investors do not rely on DPS growth rates simply based on the number of investment research firms that publish DPS estimates given that DPS growth rates of mature companies are predictable and easily forecasted (Tr. 11, at 1332). D.P.U. 23-80/D.P.U. 23-81, at 350.

The Company also claims that the Attorney General's use of a sustainable growth rate unreasonably lowers her estimated cost of equity and that the Attorney General's base assumption underlying the sustainable growth rate is not tenable (Exh. NG-AEB-Rebuttal, at 34-35, 39-42). Specifically, the Company contends that the underlying assumption that future earnings will increase as the retention ratio[218] increases is not necessarily true because the amount of earnings not paid as dividends can vary due to management decisions (Exh. NG-AEB-Rebuttal-1, at 39). The Department finds that this is not a compelling argument in the context of this proceeding as the proxy companies under analysis have stable and consistent dividends, as discussed above.

Turning to the issue of upward bias in EPS forecasts, the Department first found in 2019 that there is a strong likelihood that the Global Analyst Research Settlement mitigated systematic bias in overly optimistic stock recommendations based on the terms of the agreement, including enforcement and structural reforms. D.P.U. 19-120, at 374. The next year, the Department dismissed claims that the systematic bias in EPS had persisted after the Global Analyst Research Settlement based on two studies published in 2010 that found the forecast bias had declined significantly and analysts' forecasts generally coincided with actual earnings in the period following the Global Analyst Research Settlement. D.P.U. 20-120, at 419-420.

[218] Retention ratio refers to the portion of earnings not paid out in dividends (Exh. NG-AEB-Rebuttal-1, at 39).

In the instant proceeding, the Attorney General provided a new study comparing EPS growth rate estimates for EDCs and LDCs to the actual, or realized, EPS growth rates over the period 1985 to 2022, and thus analyzed ten more years of data after the Global Research Analyst Settlement than the third-party studies presented by the Company (Exhs. NG-AEB-Rebuttal-1, at 50-51; AG-JRW-Testimony-1, at 54-55). The Company asserts that the Attorney General's study is invalid because it includes data prior to the Global Analyst Research Settlement, and because the Attorney General's study relies on raw data that contains errors or inconsistencies (Exh. NG-AEB-Rebuttal-1, at 46-50). We disagree. The Attorney General's use of two measures of central tendency, medians and means, mitigate the impact of the types of errors in the data that the Company identified (Tr. 11, at 1319-1323). The Company identified errors with only three of the dozens of electric and gas companies included in the study and provided no evidence of the impact of these errors on the analysis (Exh. NG-AEB-Rebuttal-1, at 46-50). Taking the presence of the identified errors into consideration, we find that the Attorney General's study is compelling evidence that projected EPS growth rates remain overly optimistic and upwardly biased after the Global Research Analyst Settlement (Exh. AG-JRW-Testimony-1, at 54-55; Tr. 11, at 1319-1323). Therefore, we will consider the presence of systematically biased and overly optimistic EPS growth estimates in the parties' DCF results in our determination of the reasonable range below.

Finally, the Company criticizes the Attorney General's method for calculating her final growth rate by contending that she subjectively assigns weights to the various growth rate sources and does not provide a replicable method or any rationale for the averaging conventions used (Exh. NG-AEB-Rebuttal-1, at 42, 45-46). The record supports this argument by demonstrating that it is unclear what weights she ultimately assigns to each of the growth rate indicators considered (Exh. DPU-AG 1-9; Tr. 11, at 1336-1340). As discussed above, however, all ROE analyses require analysts to make several subjective judgments that influence the end result. D.P.U. 18731, at 59. We disagree with National Grid that the Attorney General's constant growth DCF results should be rejected entirely, but we consider the level of subjectivity found in the Attorney General's analysis in determining the weight given to the model results.

Based on our subsidiary findings above and consistent with long-standing precedent, the Department finds that it is reasonable and appropriate to consider a variety of factors when determining an appropriate growth rate for the DCF model. D.P.U. 23-80/D.P.U. 23-81, at 348-352; D.P.U. 07-71, at 136; D.T.E. 02-24/25, at 227; D.P.U. 96-50 (Phase I) at 120; D.P.U. 93-60, at 51; D.P.U. 92-250, at 147. The record evidence discussed above demonstrates that the Company's and the Attorney General's constant growth DCF results suffer from limitations and questionable assumptions, including National Grid's exclusive reliance on overly optimistic and upwardly biased EPS growth rates and an unreasonable assumption that investors would not consider DPS growth rate expectations, as well as the Attorney General's subjective method of determining the growth rate applied in her model. The Department finds that it is appropriate to consider both the Company's and the Attorney General's constant growth DCF results and the limitations thereof in our determination of the reasonable range and National Grid's authorized ROE below. Also, the Department requested National Grid to provide a revised version of its constant growth DCF model using projected DPS growth rates for its proxy group instead of projected EPS growth rates (Exh. DPU 15-8, Att.). The mean and median constant growth DCF results using projected DPS growth rates are 8.92 percent and 9.19 percent

(Exh. DPU 15-8, Att.). Based on our findings above, we find that it is reasonable and appropriate to consider these results in our determination of the reasonable range and National Grid's authorized ROE.

ii. Multi-Stage DCF

With respect to the multi-stage DCF model, the Department has considered its use as a supplement to the constant growth model in evaluating the cost of equity. D.P.U. 17-170, at 282, 292; D.P.U. 11-01/D.P.U. 11-02, at 414; D.P.U. 07-71, at 137; D.P.U. 94-50, at 459-460, 484-485. National Grid and the Attorney General disagree on whether the Company's proposed growth rate of 5.49 percent in the third stage of its multi-stage DCF model is overstated, and whether the multi-stage DCF model is necessary at all given that the utility industry is a mature industry (Exhs. NG-AEB-Rebuttal-1, at 56-57; AG-JRW-Testimony-1, at 86-88).

The multi-stage DCF model enables the analyst to allow for a gradual transition from the first-stage growth rate to the long-term growth rate, thereby avoiding the unrealistic assumption that growth changes abruptly between the first and final stages (Exh. NG-AEB-1, at 41-42). The Company has not provided any evidence that it is in either a short-term growth period or a transition period between its short-term and long-term growth periods. To the contrary, the Company's consultant acknowledges that the utility sector is a mature and stable industry, and that both she and the Attorney General's witness agree that the constant-growth DCF model is therefore the most appropriate model to rely on in the context of this proceeding (Exh. AG-JRW-Testimony-1, at 46; Tr. 4, at 535). Moreover, the Company's multi-stage DCF results suffer from the same limitations identified above with respect to the constant growth DCF results, and we find that the Company's long-term nominal GDP growth rate of 5.50 percent puts too much emphasis on the GDP growth of the first half of the 20th century, resulting in an overstated cost of equity (Exh. AG-JRW-Testimony-1, at 86-88). Therefore, the Department affords National Grid's multi-stage DCF model little weight in determining the Company's allowed ROE.

iii. CAPM

The CAPM is a well-known risk premium model that assumes investors require an excess return for investing in risky assets, such as stocks, above the yields on risk-free assets such as U.S. Treasury Bonds (Exhs. NG-AEB-1, at 45-46; AG-JRW-Testimony-1, at 61-62). To estimate the cost of equity, the CAPM requires the following inputs: (1) a risk-free rate of interest (usually using a long-term U.S. Treasury Bond); (2) an expected equity or market risk premium (i.e., the excess return that an investor expects to receive above the risk-free rate for investing in risky stocks); and (3) a beta (i.e., the systematic risk of a security measured by the covariance between the price of a stock and the price of the market index) (Exhs. NG-AEB-1, at 45-46; AG-JRW-Testimony-1, at 61-62).

Regarding betas in the CAPM, the record demonstrates that the betas selected by the Company slightly overstate the cost of equity as they utilize stock weekly returns and compare companies against the NYSE Index (Exh. AG-JRW-Testimony-1, at 65-66). Specifically, weekly returns are more volatile than monthly returns, thus inflating betas and subsequently the estimated cost of equity (Exh. AG-JRW-Testimony-1, at 65-66). Further, the S&P 500 Index, which is commonly used as a reference for the market, includes a significant number of volatile technology stocks (Exh. AG-JRW-Testimony-1, at 66; Tr. 4, at 535). Accordingly, the use of the NYSE Index, as opposed to the S&P 500 Index, inflates the betas of the companies under analysis by comparing them against a market index that is relatively less risky (Exh. AG-JRW-Testimony-1, at 66).

National Grid and the Attorney General have provided substantially different CAPM results driven primarily by differing opinions on the appropriate measure of the market risk premium (Exhs. NG-AEB-Rebuttal-1, at 60; AG-JRW-Testimony-1, at 90; AG-JRW-Surrebuttal-1, at 24; Tr. 11, at 1355). We consider the parties' proposed market risk premiums below.

National Grid's first of two approaches relies on an expected market return of 12.70 percent based on a constant growth DCF model of the companies in the S&P 500 Index that suffers from the same limitations as the Company's constant growth DCF model of the Company's proxy group, i.e., the model relies exclusively on overly optimistic and upwardly biased EPS growth rates and fails to consider other relevant measures of growth (Exhs. NG-AEB-1, at 47; NG-AEB-Rebuttal-6). Further, we disagree with the Company's assertion that an expected 12.70 percent market return is reasonable simply because the historical market return in the United States was at least 12.90 percent for 50 of the past 97 years, i.e., 52 percent of all observations (Exh. NG-AEB-1, at 49). The historical market return for the past 97 years averages 12.02 percent, which is significantly below the Company's estimated market return (Exh. DPU-NG 1-1, Att. 5). Moreover, record evidence demonstrates that GDP growth in the United States has been continually slowing down, and there is no evidence in the record to suggest that the United States will experience the same level of growth as it did over the last century (Exh. AG-JRW-Testimony-1, at 87-88, 101-108).

Also, the S&P 500 Index includes firms that are in the growth state of the business life cycle and, therefore, have a high EPS growth rate that will stabilize as these companies transition to the mature stage (Exhs. NG-AEB-1, at 47-48; AG-JRW-Testimony-1, at 66; Tr. 4, at 535). D.P.U. 23-80/D.P.U. 23-81, at 355. Accordingly, National Grid overestimates the long-term market return by assuming the S&P 500 Index companies in the growth stage, such as companies in the technology sector, will maintain a constant, high rate of EPS growth in perpetuity (Exh. NG-AEB-Rebuttal-8; Tr. 4, at 534-535). D.P.U. 23-80/D.P.U. 23-81, at 355-356. Additionally, we find that National Grid's market risk premiums of 8.60 percent, 8.58 percent, and 8.32 percent reflect an unrealistic expectation for a long-term market risk premium when compared to the arithmetic mean market risk premium from 1928 to 2022 of 6.64 percent (Exhs. NG-AEB-Rebuttal-10; AG-JRW-6 at 5). Therefore, the Department finds that the Company's CAPM results using the market risk premiums based on the S&P 500 Index companies are overstated, and we will not consider the model results in our determination of the reasonable range and authorized ROE.

As described above, National Grid also presents a CAPM result that is purportedly based on a method prescribed by the Department in D.P.U. 20-120 and D.P.U. 22-22, (Exhs. NG-AEB-1, at 47; NG-AEB-Rebuttal-6, at 1). We disagree with National Grid's characterization that the Department established a specific method for the CAPM in those proceedings. In the first referenced proceeding, the Department found that it is important to consider multiple analytical methods to mitigate model bias and the limitations and questionable assumptions found in each model. D.P.U. 20-120, at 429. In an effort to consider a broader range of CAPM analyses for that purpose, the Department directed all EDCs and LDCs to submit a CAPM analysis in their future base distribution rate proceedings that estimates the market return based on the Value Line universe of companies using Value Line's median of estimated dividend yields and estimated price appreciation potential. D.P.U. 20-120, at 428-429. In the following base distribution rate case adjudicated by the Department, we reviewed a traditional CAPM result of 10.50 percent that was calculated based on a combination of the expected return for the S&P 500 Index, the expected return for Value Line universe of companies, and historical return data and determined, based on the reasonableness of the ROE estimate in light of the Departments findings in that proceeding, that the analysis warranted some weight. D.P.U. 22-22, at 391 n.190, 397. Nevertheless, the Department expressly declined to establish the market return calculation submitted in D.P.U. 22-22 as the only approach that would be accepted in future cases, and we determined that the Department would continue to evaluate the probative value of parties' CAPM analyses and other ROE estimated models on a case-by-case basis. D.P.U. 22-22, at 391 n.190.

After review, the record in this proceeding shows that the expected return for the Value Line universe of companies has a tempering effect on the CAPM results using the weighted market risk premium (Exh. NG-AEB-Rebuttal-10). Nonetheless, the weighted market risk premium includes National Grid's market risk premium based on the S&P 500 Index that overstates the cost of equity and a historic market risk premium that, when considered in light of current and projected trends in GDP growth, likely overstates the cost of equity as well (Exhs. NG-AEB-Rebuttal-10; NG-AEB-1, at 47; NG-AEB-Rebuttal-6; AG-JRW-Testimony-1, at 87-88, 101-108). Further, the Company's CAPM results include beta coefficients that likely overstate the risk of the Company's proxy group and the Attorney General's proxy group, as discussed above (Exh. AG-JRW-Testimony-1, at 65-66). Accordingly, we will not rely on the Company's CAPM results based on the weighted market risk premium in our determination of the reasonable range and authorized ROE (Exh. NG-AEB-Rebuttal-2).

Next, we consider the propriety of the Attorney General's proposed CAPM results. Consistent with long-standing Department precedent, the Department finds that the Attorney General's approach of reviewing various market risk premium studies by finance firms and valuation experts and surveys of financial analysts, academics, and companies is a preferrable approach to developing a market risk premium than the Company's approach. D.P.U. 23-80/D.P.U. 23-81, at 356; D.P.U. 18-150, at 483; D.P.U. 17-170, at 299; D.P.U. 15-155, at 371. The CAPM is considered a forward-looking model that recognizes that investors are generally risk averse and will demand higher returns in exchange for assuming higher levels of investment risk; therefore, it is appropriate to base the market risk premium on investors' perception of risk. D.P.U. 18-150, at 483; D.P.U. 17-170, at 299; D.P.U. 15-155, at 371; D.P.U. 13-90, at 225-226; D.P.U. 13-75, at 314. Compared to the Attorney General's reliance on several well-known investment firms, leading finance scholars, financial analysts, and valuation experts, the Company's market risk premium is the result of an analysis based on the findings of only one expert (Exh. AG-JRW-Surrebuttal-1, at 30-33). The Department acknowledges the Company's argument that the Attorney General's consultant's market risk premium of 5.25 percent was not determined using formulas that allow it to be replicable and directly traced back to the studies and surveys reviewed (Exh. NG-AEB-Rebuttal-1, at 60; Tr. 11, at 1353-1354). The Department, however, also observes that the market risk premium of 5.25 percent used by the Attorney General is well within the range determined using the surveys and studies discussed above (i.e., 3.40 percent to 5.50 percent). Accordingly, we find it is reasonable and appropriate to consider the Attorney General's CAPM results in our determination of the reasonable range and authorized ROE and accord the Attorney General's CAPM result more weight that the Company's CAPM results.

iv. Empirical CAPM

The Department has previously rejected the empirical CAPM. D.P.U. 23-80/D.P.U. 23-81, at 357; D.P.U. 22-22, at 392; D.P.U. 10-70, at 271. We are not persuaded to deviate from our prior treatment of the empirical CAPM results because the Company and the Attorney General provide contradictory expert testimony on the validity of the empirical CAPM (Exhs. NG-AEB-Rebuttal-1, at 72-77; AG-JRW-Testimony-1, at 89-90; AG-JRW-Rebuttal-1, at 24). Further, the Attorney General points out that the study put forth by the Company in defense of its empirical CAPM is not relevant because it reviews historical, not projected, market risk premiums (Tr. 11, at 1311-1315). The Attorney General also notes that the Company's empirical CAPM uses weights to adjust its risk-free rate and market risk premium with no empirical justification for the weights selected (Exh. AG-JRW-Testimony-1, at 89-90). Notably, National Grid places little if any weight on its empirical CAPM results given that the Company's empirical CAPM model results are the only model results that fall outside of the Company's reasonable range entirely (Exh. NG-AEB-Rebuttal-2). Furthermore, the Company's empirical CAPM results rely on the same market risk premiums that we analyzed and rejected above. Therefore, the Department finds that the Company's empirical CAPM results are unreliable estimates of National Grid's cost of equity.

v. Bond Yield Risk Premium

The Department has repeatedly found that the bond yield risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. D.P.U. 18-150 at 488-490; D.P.U. 10-114, at 322; D.P.U. 88-67 (Phase I) at 182-184. More specifically, the Department has found that the return on long-term corporate or public utility bonds may have risks that could be diversified with the addition of common stock in investors' portfolios and, therefore, the risk premium model overstates the risk accounted for in the resulting cost of equity. D.P.U. 10-114, at 322; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Nonetheless, the Department has acknowledged the value of the risk premium model as a supplemental approach to other models. D.P.U. 10-114, at 322; D.T.E. 02-24/25, at 228, citing D.T.E. 99-118, at 86-87.

The Department finds flaws inherent in the bond yield risk premium analysis presented by the Company. As the Department has previously recognized, there is a circularity inherent in the use of authorized utility returns to derive the risk premium. D.P.U. 18-150, at 489; D.P.U. 13-75, at 319; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Also, utility- and rate-case specific information are factors in the determination by regulatory commissions of an appropriate ROE (Exh. AG-JRW-Testimony-1, at 109). To the extent that allowed ROEs incorporate some type of penalty for deficient management (or, conversely, recognize superior management), the results of the comparative analysis will either tend to understate or overstate the required risk premium (Exh. AG-JRW-Testimony-1, at 109). Moreover, the Company's authorized ROE input includes authorized ROEs for all electric utilities, including vertically integrated electric utilities (Exh. AG-JRW-Testimony-1, at 20-21, 110). On average, delivery-only electric utilities have allowed ROEs 30 to 50 basis points lower than vertically integrated electric utilities, due to the latter being considered a higher risk (Exh. AG-JRW-Testimony-1, at 20-21, 110). Therefore, we find that the Company's bond yield risk premium model overstates National Grid's cost of equity, and we will not rely on the model results in our determination of the reasonable range and authorized ROE. Further, the Department finds that the CAPM model, which measures risk using proxy company-specific betas rather than authorized ROEs, is a more reliable model.

c. Reasonable Range

Based on our precedent and analysis of the record evidence, the Department has made the following findings regarding the ROE model results propounded by National Grid and the Attorney General. First, we found that it is appropriate to consider National Grid's constant growth DCF results (i.e., 10.11 percent to 10.32 percent), the constant growth DCF model provided by National Grid using DPS growth rates (i.e., 8.92 percent and 9.19 percent), and the Attorney General's constant growth DCF results (i.e., 9.71 percent and 9.76 percent)[219] in the determination of the reasonable range, subject to the limitations and questionable assumptions discussed above. Second, we found that it is appropriate to accord little weight to the Company's multi-stage DCF model results because the constant growth DCF model is the most appropriate DCF analysis for utilities. Third, we found that it was appropriate to consider the

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[219] These are the Attorney General's results with rounding to the nearest 0.05 percent removed.

Attorney General's CAPM results (i.e., 8.97 percent and 8.98 percent)[220] in the determination of the reasonable range and accord the Attorney General's CAPM results more weight than the Company's CAPM results. Lastly, we rejected National Grid's CAPM, empirical CAPM, and bond yield risk premium model results. 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 9.00 percent to 10.10 percent is a reasonable range of ROEs for National Grid in this proceeding.

d. Market Conditions and Trends in Authorized ROEs

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. 23-80/D.P.U. 23-81, at 362-363; 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. 23-80/D.P.U. 23-81, at 362-363; D.P.U. 20-120, at 434-435; D.P.U. 17-170, at 280.

In this proceeding, some evidence suggests that long-term interest rates and inflation will remain elevated, negatively affecting valuations for the utility industry (Exh. NG-AEB-1, at 19-29). After review, however, we determine that more evidence supports a finding that interest rates and inflation are expected to decrease and that the outlook for utilities is positive.

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220 These are the Attorney General's results with rounding to the nearest 0.05 percent removed.

For example, S&P Global Ratings reports an improved outlook for the utility sector despite the various risk factors discussed, including inflation (Exh. DPU 1-5). Specifically, S&P Global Ratings states that "[o]ur outlook for the industry as a whole reflects the increasing percentage of utilities with a stable outlook, lower natural gas prices, and a slowing of inflation" (Exh. DPU 4-9). Similarly, Moody's has improved the utility industry's outlook from negative to stable (Exh. NG-AEB-1, at 73). The Department also notes that share prices for the utility industry have increased during this proceeding, as demonstrated by a 7.60 percent increase in the S&P 500 Utilities Index (Exh. DPU 4-15). Accordingly, the Department does not find that utility industries are being negatively valued at this time. Further, year-over-year inflation has declined on a monthly basis since October 2022 (Exh. AG-JRW-Testimony-1, at 15). The Attorney General also presents testimony that an inverted yield curve suggests that the economy may enter into a recession and, as a result, lower interest rates in the future (Exh. AG-JRW-Testimony-1, at 17-19). Moreover, the Company's own testimony and analysis show that current U.S. Treasury bond yields are higher than U.S. Treasury bond yields expected in the near future (Exhs. NG-AEB-1, at 20, 22; NG-AEB-Rebuttal-1, at 80-81; NG-AEB-Rebuttal-11). Based on the record evidence, the Department finds that the record on current and expected market conditions is compelling evidence that National Grid's cost of equity during the PBR term will be lower than the cost of equity indicated by the market data from September 2023 and March 2024 used in the Company's models. Therefore, the Department determines that consideration of the evidence on market conditions supports an allowed ROE in the lower half of the reasonable range.

Relatedly, National Grid argues that the ROE authorized in this proceeding should be higher than the ROE authorized in its last base distribution rate case because interest rates have significantly increased (Company Brief at 431). Although interest rates have increased since the Department's decision in D.P.U. 18-150, the Company's focus on interest rates alone disregards the Department's key findings related to the cost of equity models and changes to the Department's precedent since 2019. Leading up to that decision, the Department's determination of the reasonable range and authorized ROE typically accorded the most weight to the results of a DCF analysis and accorded limited weight to ROE estimates based on the CAPM. See e.g., D.P.U. 20-120, at 396; D.P.U. 17-05-H at 13; D.P.U. 18-150, at 482; D.P.U. 15-155, at 470. As noted above, however, in 2021 the Department determined that it is important to consider multiple analytical methods to determine an appropriate ROE. D.P.U. 20-120, at 429. Based on the record evidence provided in the adjudicated base distribution rate cases that have followed, the Department has: (1) accorded more weight to the results of the CAPM than it has in the past; (2) reaffirmed that estimating the market risk premium based on studies by finance firms and valuation experts and surveys of financial analysts, academics, and companies is a better approach than using a constant growth DCF model; and (3) found that exclusive reliance on EPS growth rates in the constant growth DCF model diminishes the probative value of the results. D.P.U. 23-80/D.P.U. 23-81, at 348-352, 356, 361-362; D.P.U. 22-22, at 397. As explained throughout this Order, we have considered the parties' arguments in this proceeding on each of these key issues and determined the reasonable range and authorized ROE in accordance with the findings supported by the preponderance of evidence. Moreover, current and projected interest rates are direct inputs of the CAPM and priced into the market data used in the constant growth

DCF model and, therefore, our determination of the reasonable range based on the model results listed above accounts for the impacts that the increase in interest rates since 2019 have had on National Grid's cost of capital.

Finally, we have considered the Attorney General's arguments concerning trends in authorized ROEs (Attorney General Brief at 91). As discussed above with respect to the bond yield risk premium model, it is inherently circular to base the appropriate ROE for National Grid on the ROEs authorized by other jurisdictions. Further, as explained by the Attorney General, decisions by regulatory commissions consider utility- and rate-case specific information that may not be applicable to National Grid (Exh. AG-JRW-Testimony-1, at 109). See also D.P.U. 20-120, at 435 (finding that purported upward trend in Massachusetts authorized ROEs from 2012 to 2020 was skewed by decisions that authorized lower ROEs because of mismanagement). While ROEs granted in other jurisdictions may be indicative of general overall trends, without knowing what quantitative and qualitative factors were considered by these other regulatory agencies, the Department is unable to conclude that the ROEs of other companies are appropriate for National Grid's ROE. D.P.U. 20-120, at 435.[221]

e. Investment Risk

The Attorney General argues that the Department should evaluate National Grid's investment risk relative to the proxy group based on its prior credit rating of A- because S&P

221 Although our decision on the reasonable range and authorized ROE does not rely on the national trends in authorized ROEs provided by the Attorney General, the Department notes that the midpoint of the reasonable range determined above and the authorized ROE determined below are comparable to the 2022 and 2023 averages for all electric companies (9.54 percent and 9.60 percent) and distribution-only electric companies (9.11 percent and 9.26 percent) (Exh. AG-JRW-Testimony-1, at 20-21).

Global Ratings downgraded the Company to its current credit rating of BBB+ due to rate regulation issues with its parent company that have nothing to do with the Company's U.S. operations (Attorney General Brief at 64, citing Exh. AG-JRW-Testimony-1, at 29). She concludes that National Grid's investment risk and cost of equity are lower than the risk and cost of equity of the proxy groups because National Grid's prior A- credit rating is higher than the current average for the proxy groups (Attorney General Brief at 64, citing Exh. AG-JRW-Testimony-1, at 29). The Department is not persuaded by this argument.

Credit ratings provide investors with relevant information with respect to a company's risk level and, therefore, serve as a suitable proxy for National Grid's business and financial risks to equity investors. D.P.U. 23-80/D.P.U. 23-81, at 364; D.P.U. 20-120, at 430. Although National Grid's credit downgrade may not be attributable to U.S.-based operations, the Company's current credit ratings affect its overall cost of borrowing and act as a signal to investors (Exh. NG-AEB-1, at 12). D.P.U. 20-120, at 431. Therefore, the Department relies on National Grid's BBB+ credit rating and finds that a downward adjustment to National Grid's authorized ROE based on its credit rating is not warranted.

The Attorney General also alleges that an adjustment is needed for the Company's higher common equity ratio (Attorney General Brief at 54-55, 57). We disagree. National Grid's common equity ratio is higher relative to the proxy group only if the comparison is done using the book value of debt and equity of the holding company's capital structure instead of market value of debt and equity based on the Company's capital structure (Exhs. NG-AEB-Rebuttal-1, at 87-93; AG-JRW-3, at 1; AEB-Rebuttal-15; Tr. 4, at 521). The Department is not convinced that using the book value of debt and equity, as the Attorney General has done, is a superior way of estimating and comparing capital structures compared to the Company's methodology, which demonstrates that the Company's common equity ratio is comparable to the proxy companies (Exhs. NG-AEB-Rebuttal-1, at 87-93; NG-AEB-Rebuttal-15; Tr. 4, at 521). Additionally, credit rating agencies consider a firm's financial and business risks in their rating determinations, so National Grid's credit rating being equal to the average credit rating of the proxy companies further supports our decision not to adjust the Company's ROE based on its capital structure. D.P.U. 23-80/D.P.U. 23-81, at 364. Accordingly, the Department finds that it is not appropriate to authorize a lower ROE for National Grid based on the Attorney General's arguments that the Company has less financial risk due to its common equity ratio.

Further, the Attorney General contends that an ROE on the lower end of her proposed range of reasonable ROEs is appropriate as it accounts for the fact that the utility industry is lower risk as measured by beta (Exh. AG-JRW-Testimony-1, at 41-42, 79). The Department finds that risk as measured by beta is already incorporated into the CAPM model (Exh. DPU-AG 1-18). Therefore, it is redundant to factor in risk as measured by beta in selecting an ROE within the range of reasonable ROEs beyond that already incorporated into the CAPM as determined by the Department.

In our decision on National Grid's allowed ROE below, we have also considered the Company's positions that its planned level of capital expenditures adversely affects its risk profile and its proposed PBR-O mechanism and ISRE mechanism do not lower the Company's risk relative to the companies in the proxy group (Company Brief at 415-416, citing Exh. NG-AEB-1, at 57-61). In the past, the Department has found that a PBR plan's more timely and flexible cost recovery serves to reduce a company's risks while a stay-out provision as part of a PBR plan may increase a company's risks in meeting its financial requirements. D.P.U. 22-22, at 403; D.P.U. 20-120, at 431-432; D.P.U. 19-120, at 405 405. Additionally, the Department previously has found that the purported risks imposed by Massachusetts policy and legislative changes designed to enable the clean energy transition would affect a company to a lesser degree in the context of a five-year stay-out provision. D.P.U. 20-120, at 433. Moreover, the credit rating agencies account for the operating environment in Massachusetts in their rating determinations, meaning the potential risk implications of the clean energy transition in Massachusetts have already been considered in National Grid's credit ratings. D.P.U. 23-80/D.P.U. 23-81, at 364.

Further, National Grid's purported analysis of the capital tracking mechanisms employed by the companies in its proxy group does not support a finding that the Company's PBR-O mechanism and ISRE mechanism do not reduce the Company's risk compared to the proxy group. The Company's analysis merely shows which operating companies have some form of capital tracking mechanism, the components of which can vary considerably (Exhs. NG-AEB-1, at 61; NG-AEB-13). National Grid has not provided any evidence about how the capital trackers employed by the operating companies in its proxy group compare to the PBR-O mechanism and ISRE mechanism. Moreover, the record shows that, aside from the companies in Massachusetts, none of the operating companies in the Company's proxy group operates in a jurisdiction that uses the I-X PBR construct (Exhs. NG-AEB-13; DPU 18-1). Therefore, the Company has not demonstrated that a representative number of the proxy companies operate under a regulatory construct that provides for as timely and flexible cost recovery as the PBR-O mechanism and ISRE mechanism approved in this proceeding. Moreover, the Department's decision to allow targeted cost recovery of ESMP expenditures provides sufficient certainty to the Company and its investors regarding recovery of the revenues necessary to support the ramp up in clean energy investments associated with achieving the Commonwealth's GHG emissions targets. D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12 at 447.

After review of the record evidence discussed above, we find that National Grid's financial risk, as evidenced by its capital structure and credit rating, is comparable to the financial risk of the proxy groups. Further, we find that the revenue support that will be provided by the Company's PBR-O mechanism, ISRE mechanism, and ESMP cost recovery mechanism lowers its investment risk compared to the proxy groups and, therefore, National Grid's authorized ROE should be set in the lower half of the reasonable range.

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; Aquarion Water Company of Massachusetts, D.P.U. 08-27, at 134-138 (2009); 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[222] 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 case consultants warranted ROE at lower end of reasonable range). Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on above-average or subpar management performance and customer service.

In Section XIII.D.3 above, the Department found that National Grid complied with the directives set forth in D.P.U. 19-117-B at 13-14 and we concluded that any incremental implementation costs that the Company incurred were de minimis in comparison to the improvements in operations and productivity of the Company's management and personnel expected through the implementation of the FTI Report's recommendations. Additionally, in Section XI.E above, the Department found that the Company's share of IASC stranded costs related to National Grid USA's Rhode Island Sale have been fully eliminated, mitigated, and/or

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[222] See, e.g., In re Citizens Utilities Company, 171 Vt. 447, 453 (2000) (general principle that rates may be adjusted depending on the adequacy of the utility's service and the efficiency of its management); Gulf Power Company v. Wilson, 597 So.2d 270, 273 (1992) (regulator was authorized to adjust rate of return within reasonable range to adjust for mismanagement); Wisconsin Pub. Serv. Corp. v. Citizens' Util. Bd., Inc., 156 Wis.2d 611, 616 (1990) (prudence is a factor regulator considers in setting utility rates and can affect the allowed ROE); US West Commc'ns, Inc. v. Washington Utils. and Transp. Comm'n, 134 Wash.2d 74, 121 (1998) (a utility commission may consider the quality of service and the inefficiency of management in setting a fair and reasonable rate of return); North Carolina ex rel. Utils. Comm'n v. Gen. Tel. Company of the Southeast, 285 N.C. 671, 681 (1974) (the quality of the service rendered is, necessarily, a factor to be considered in fixing the just and reasonable rate therefore).

absorbed. Therefore, we find that a downward adjustment to National Grid's authorized ROE based on deficient management performance is not warranted in this case.

E. 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 9.35 percent is within a reasonable range of cost of equity rates that will preserve the Company's financial integrity, allow it to attract capital on reasonable terms and, for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case. The Department also notes that our decisions in this Order approving the PIMs relating to enrollment of income-eligible customers and DER interconnections provide the Company with additional opportunities to enhance its earnings through successful implementation of initiatives that are aligned with the Commonwealth's and the Department's affordability and clean energy goals. In making these findings, 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.

XV. RATE STRUCTURE

A. Rate Structure Goals

Rate structure defines the level and pattern of prices charged to each customer class for its use of utility service. The rate structure for each rate class is a function of the cost of serving that rate class and how rates are designed to recover the cost to serve that rate class. The Department has determined that the goals of designing utility rate structures are to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. G.L. c. 25, § 1A; D.P.U. 23-80/D.P.U. 23-81, at 367; D.P.U. 22-22, at 404; D.P.U. 20-120, at 412; D.P.U. 19-120, at 409.

Efficiency means that the rate structure should allow a company to recover the cost of providing the service and should provide an accurate basis for consumers' decisions about how to best fulfill their needs. The lowest-cost method of fulfilling consumers' needs should also be the lowest cost means for society as a whole. Thus, efficiency in rate structure means that it is cost-based and recovers the cost to society of the consumption of resources to produce the utility service. D.P.U. 23-80/D.P.U. 23-81, at 367-368; D.P.U. 22-22, at 405; D.P.U. 20-120, at 412; D.P.U. 19-120, at 409.

The Department has determined that a rate structure achieves the goal of simplicity if it is easily understood by consumers. Rate continuity means that changes to rate structure should be gradual to allow consumers to adjust their consumption patterns in response to a change in structure. In setting rates, the Department balances fairness and equity. Fairness means that no class of consumers should pay more than the costs of serving that class. Equity, in rate structure, means that the Department considers affordability among customers in establishing rate classes and when establishing discount rates for low-income customers.[223] Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. G.L. c. 25, § 1A; D.P.U. 23-80/D.P.U. 23-81, at 368; D.P.U. 22-22, at 405; D.P.U. 20-120, at 413; D.P.U. 19-120, at 409-410.

[223] The Department addresses the low-income discount rate and compliance with G.L. c. 164, § 141 in Section X.V.I. below.

There are two parts to determine rate structure: cost allocation and rate design. Cost allocation assigns a portion of a company's total costs to rate classes through an embedded ACOSS. The ACOSS represents the cost of serving each rate class at equalized rates of return given the company's level of total costs. D.P.U. 23-80/D.P.U. 23-81, at 368; D.P.U. 22-22, at 405-406; D.P.U. 20-120, at 413; D.P.U. 19-120, at 410.

There are four steps to develop an ACOSS. The first step is to functionalize costs. In this step, costs are associated with the production, transmission, or distribution function of providing service. The second step is to classify the costs in each functional category according to the factors underlying their causation. Thus, the costs are classified as demand-, energy-, or customer-related. The third step is to identify an allocator that is most appropriate for costs in each classification within each function. The fourth step is to allocate all of a company's costs to each rate class based upon the cost groupings and allocators chosen and then to sum for each rate class the costs allocated to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 23-80/D.P.U. 23-81, at 368-369; D.P.U. 22-22, at 406; D.P.U. 20-120, at 413; D.P.U. 19-120, at 410.

The results of the ACOSS are compared to normalized revenues billed to each rate class in the test year. If these amounts are reasonably comparable, then the revenue increase or decrease may be allocated among the rate classes so as to set rates at equalized rates of return to ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 23-80/D.P.U. 23-81, at 369; D.P.U. 22-22, at 406; D.P.U. 20-120, at 414; D.P.U. 19-120, at 411.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an ACOSS, but also explicitly considers the effect of its rate structure decisions on the amount that customers are billed. For instance, the pace at which fully cost-based rates are implemented depends, in part, on the effect of the changes on customers. In addition, considering the goals of efficiency and fairness, the Department has also ordered the establishment of special rate classes for certain low-income customers and considers the effect of such rates and rate changes on low-income customers. G.L. c. 25, § 1A; D.P.U. 23-80/D.P.U. 23-81, at 369; D.P.U. 22-22, at 407; D.P.U. 20-120, at 414; D.P.U. 19-120, at 411. To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies, or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i).[224] In addition, G.L. c. 164, § 94*I* ("Section 94*I*") requires the Department, in each base distribution rate proceeding, to design rates based on equalized rates of return by customer class as long as the resulting impact for any one customer class is not more than ten percent.[225]

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224 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.

225 Section 94*I* provides:

> In each base distribution rate proceeding conducted by the Department under Section 94, the Department shall design base distribution rates using a

The Department reaffirms its rate structure goals are designed to result in rates that are fair and cost-based and that enable customers to adjust to changes. D.P.U. 23-80/D.P.U. 23-81, at 370; D.P.U. 22-22, at 408; D.P.U. 20-120, at 415; D.P.U. 19-120, at 412.

The second part of determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the costs 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. 23-80/D.P.U. 23-81, at 370; D.P.U. 22-22, at 408; D.P.U. 20-120, at 415; D.P.U. 19-120, at 412.

B. Cost Allocation

1. Company Proposal

National Grid performed an ACOSS to directly assign or allocate each element of the revenue requirement, including plant and other investments, O&M expenses, depreciation expense, and taxes, among the rate classes to determine the costs of providing distribution service to each rate class (Exh. NG-PP-1, at 5-6). Each element of the revenue requirement is analyzed and assigned to or allocated among the rate classes for the purpose of establishing rates,

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cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any one customer class would be more than ten percent, the Department shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the Department.

subject to assumptions such as kWh delivery volume, peak kilowatt (“kW”) demand, and number of customers, that allow the utility a fair opportunity to recover its costs and earn a fair return on its investments (Exh. NG-PP-1, at 6). The Company’s ACOSS entails three primary steps: (1) functionalization; (2) classification; and (3) allocation (Exh. NG-PP-1, at 6). For the first step, the Company functionalized each element of the cost of service into: (1) primary distribution; (2) secondary distribution; and (3) billing (Exh. NG-PP-1, at 6). The purpose of the primary distribution function, which includes substations, conductors rated four kV and higher, and costs associated with transmission and production activities that are included in the cost of service, is to move energy from upstream facilities to more localized areas and directly to customers in some cases (Exh. NG-PP-1, at 8). The secondary distribution function includes conductors and related assets that move electricity from the primary distribution system to customers’ premises, including service drops to enable its customers to use the energy supplied (Exh. NG-PP-1, at 8). The billing function includes costs related to measuring, billing, and collecting for the services the Company provides, including customer support (Exh. NG-PP-1, at 8).

Assets and costs are generally functionalized following FERC’s Uniform System of Accounts. Costs were directly assigned to a function wherever possible (Exh. NG-PP-1, at 16). Some accounts were functionalized to more than one function based on special studies, and other accounts that included multiple functions were functionalized proportionally (Exh. NG-PP-1, at 16).

In the second step, the Company classified each functionalized cost element as: (1) demand-related; (2) energy-related; or (3) customer-related (Exh. NG-PP-1, at 6). The

Company classified all assets and costs in the primary distribution function as demand-related, and all assets and costs in the billing function as customer-related (Exh. NG-PP-1, at 17). The secondary distribution function includes demand-related and customer-related elements, along with elements that are allocated between demand and customers (Exh. NG-PP-1, at 17). Services are classified as customer-related due to their direct relationship to the number of customers (Exh. NG-PP-1, at 17). Assets upstream of services, which deliver energy to the service drop, are classified as demand-related based on system or local-area peak demand (Exh. NG-PP-1, at 17-18). Costs are classified in the same manner as the assets to which they relate (Exh. NG-PP-1, at 18).

The final step in the ACOSS process is cost allocation. In this step, the Company allocated each functionalized and classified cost element to each rate class (Exh. NG-PP-1, at 6). The Company notes that it utilized the same method in preparing the ACOSS as it did in its prior base distribution rate cases, D.P.U. 09-39, D.P.U. 15-155, and D.P.U. 18-150 (Exh. NG-PP-1, at 6). According to the Company, this consistent three-step method, which has been previously accepted by the Department and other regulators, is widely used, and is supported by the Electric Utility Cost Allocation Manual (January 1992) of the National Association of Regulatory Utility Commissioners (Exh. NG-PP-1, at 6-7). The Company further adds that the allocator assignments in this case are the same as in its previous three base distribution rate cases with one modification (Exh. NG-PP-1, at 7, citing D.P.U. 09-39, D.P.U. 15-155, D.P.U. 18-150). The demand allocators in the previous three cases were calculated using data from a single year, whereas in this case, the Company examined data for the fiscal year ending March 31, 2015 through March 31, 2023, and used the averages of the demand allocators over that time period (Exh. NG-PP-1, at 14).

After finalizing the initial revenue allocation to each rate class, the Company next determined whether it was necessary to reallocate any revenues between rate classes to meet the requirements of Section 94*I* and the Department's rate continuity goal (Exhs. NG-PP-1, at 22-24; NG-PP-4, at 1-3 (Rev. 4)).[226] Section 94*I* requires that no rate class receive an increase in distribution revenue that is greater than ten percent of that class's total annual normalized revenue from all rates and charges, including imputed commodity revenue for customers with competitive suppliers. In this case, the Company determined that the increase to the street lighting classes exceeded ten percent and, as such, the Company reduced the proposed base distribution revenue increase such that it was equal to ten percent of total annual normalized revenue for those classes (Exhs. NG-PP-1, at 23; NG-PP-4, at 2 (Rev. 4)). The reduction to the street lighting classes revenues were recovered from the other rate classes in proportion to their revenue requirements, as shown in the ACOSS (Exhs. NG-PP-1, at 23; NG-PP-4, at 2 (Rev. 4)). To further ensure the revenue requirement assigned to each rate class meets the Department's rate continuity goal, the Company proposed to limit the percentage distribution increase to two times (i.e., 200 percent) the overall average base distribution revenue increase (Exhs. NG-PP-1, at 23-24; NG-PP-4, at 3 (Rev. 4)). No adjustment was required to meet this goal (Exhs. NG-PP-1, at 24; NG-PP-4, at 3 (Rev. 4)).

[226] Exhibit NG-PP-4, at 1-3 (Rev. 4) is also known as Department Schedule 10.

2. Positions of the Parties

a. Attorney General

The Attorney General recommends the Department direct the Company to modernize its ACOSS approach in its next base distribution rate case (Attorney General Brief at 124). While the Attorney General does not oppose National Grid's proposal to use demand allocators based on averages from fiscal year-end March 31, 2015 through March 31, 2023 for its ACOSS rather than a single year of demand, she argues that to develop an ACOSS that reflects the costs of a modernized power system, the Company should move away from its reliance on class, non-coincident peak demand allocators for allocating primary distribution and substation costs (Attorney General Brief at 124-130). The Attorney General asserts that the Company instead should conduct a temporal analysis to evaluate how class loads contribute to peak demand immediately before, during, and after a circuit peaks, including time-of-day information, differentiated by season/month and asset type (Attorney General Brief at 124-130). Further, the Attorney General contends that using a single hour of peak demand to determine costs is inaccurate, as the system is built to accommodate demand at all times, not just during one peak hour (Attorney General Brief at 126). Therefore, the Attorney General urges the Department to direct the Company to move away from reliance on non-coincident peak demand allocators and instead use data closer to the present time, such as over one to three years, and rely on more data points to better understand customer energy usage (Attorney General Brief at 124, 126-127, citing Exhs. AG-RNCP-1, at 18; AG-RNCP-Surrebuttal-1, at 2).

For the temporal analysis, the Attorney General recommends analyzing each customer class's contribution to the top 100 (or otherwise representative) load hours on primary distribution assets and substations during the study period while continuing to allocate secondary distribution assets via non-coincident peak due to its localized nature (Attorney General Brief at 127, citing Exhs. AG-RNCP-Surrebuttal-1, at 2; NG-AG 1-1). Additionally, the Attorney General argues that the Company should begin collecting data when AMI deployment begins to provide more comprehensive information, to support the development of more advanced, time-differentiated rate offerings by accounting for peak and near-peak loads (Attorney General Brief at 127). The Attorney General contends that this approach will improve cost allocation accuracy by recognizing that capacity upgrades are often triggered by consecutive hours of high load (Attorney General Brief at 127).

Further, the Attorney General asserts that, in future base distribution rate cases, a new ACOSS is necessary to provide an up-to-date snapshot of each class's contribution to system costs and in turn to determine cost causation (Attorney General Reply Brief at 39). The Attorney General argues that the Company's reliance on data from as far back as 2015 risks misallocating costs due to outdated demand patterns that may not reflect current usage trends, particularly in light of economic or technological changes for heating methods, vehicle electrification, and the adoption of light emitting diode, i.e., LED, lighting (Attorney General Reply Brief at 39).

Finally, the Attorney General emphasizes that while it may be appropriate to consider other ratemaking principles such as cost-causation, gradualism, rate continuity, fairness, and equity, an ACOSS should initially consider cost-causation principles as a starting point for cost-based rates (Attorney General Brief at 129). The Attorney General asserts that these results must be balanced with the other key principles to determine appropriate and reasonable revenue allocation among classes, consistent with the Department's ratemaking goals (Attorney General Brief at 127).

b. TEC and PowerOptions

TEC and PowerOptions urge the Department to reject the Company's proposal to use an average of multiple years' demands to develop demand allocators and instead require the use of a representative annual period in accordance with past practice (TEC and PowerOptions Brief at 6, citing Exh. NG-PP-1, at 13-14). They argue that the nine-year period is inappropriate due to the rapid changes in load patterns and the potential for inter-generational inequities among ratepayers (TEC and PowerOptions Brief at 6; TEC and PowerOptions Reply Brief at 3, citing Exh. TEC/PO-JDB/AN-1, at 21-22). TEC and PowerOptions assert that the Company has not shown that a nine-year period better reflects cost causation than recent annual data (TEC and PowerOptions Brief at 6; TEC and PowerOptions Reply Brief at 3, citing Exh. TEC/PO-JDB/AN-1, at 21-22).

Further, TEC and PowerOptions contend that the Company has not identified specific abrupt changes or anomalies in the load data that necessitate this significant change in ratemaking practice (TEC and PowerOptions Reply Brief at 3, citing Exh. TEC 2-1). TEC and PowerOptions assert that their witnesses have documented the rapid pace of change of load patterns since 2014 and have shown that older data is not reflective of current conditions (TEC and PowerOptions Brief at 7; TEC and PowerOptions Reply Brief at 4). TEC and PowerOptions maintain that the nine-year term would result in outdated data being used and lead to the Company's proposed cost-based rates being inaccurate (TEC and PowerOptions Brief at 7).

Additionally, TEC and PowerOptions assert that the Section 94*I* cost caps are sufficient to promote gradualism, move rates closer to costs, and prevent rate shock, all of which mitigates abrupt changes in rates (TEC and PowerOptions Brief at 7; TEC and PowerOptions Reply Brief at 4). They argue that the nine-year period would only hinder the goal of setting rates based on actual customer contributions and cost-causation activities and would result in delayed and inaccurate price signals (TEC and PowerOptions Brief at 7-8).

Finally, TEC and PowerOptions assert that demand allocators should reflect current system load conditions, with abrupt changes mitigated through the existing caps under Section 94*I* (TEC and PowerOptions Brief at 8). They contend that the Company has failed to identify specific abrupt changes or anomalies in the load data that justify this significant change in ratemaking practice (TEC and PowerOptions Brief at 7-8; TEC and PowerOptions Reply Brief at 3-4). TEC and PowerOptions maintain that the "abrupt changes" cited by the Company pertain to changes in relative returns by rate class, not the load data itself (TEC and PowerOptions Brief at 7-8; TEC and PowerOptions Reply Brief at 4). TEC and PowerOptions assert that rates should be based on recent representative data reflecting current customer usage (TEC and PowerOptions Reply Brief at 4). Therefore, TEC and PowerOptions urge the Department to reject the Company's nine-year period proposal and require demand allocators to represent current system load conditions with abrupt changes mitigated through the existing Section 94*I* caps (TEC and PowerOptions Brief at 8; TEC and PowerOptions Reply Brief at 4).

c. <u>Company</u>

National Grid argues that it conducted its ACOSS study in a similar manner to its approach in its previous rate case, which it notes the Department found acceptable (Company

Brief at 536, citing D.P.U. 18-150, at 511). Therefore, the Company requests that the Department find that the ACOSS study in the instant proceeding is acceptable (Company Brief at 536). Regarding the intervenor positions, the Company acknowledges its shared position with the Attorney General on the necessity of utilizing more than a single annual data point to inform demand allocators in an ACOSS (Company Brief at 551; Company Reply Brief at 87). Nonetheless, the Company opposes the Attorney General's recommendation to develop the demand allocators based on a limited set of cost-causing hours over one to three years (Company Brief at 551). The Company argues that limiting the data period arbitrarily to such a narrow timeframe could lead to the exclusion of relevant data and potentially lead to non-representative results due to a anomalies or non-recurring events within those selected years (Company Brief at 551; Company Reply Brief at 87). Instead, the Company advocates for a broader review of all available years of data, subject to trend analysis and identification of outliers, and asserts that this approach offers a more reliable basis for developing the demand allocators (Company Brief at 551). The Company further argues that this approach ensures that cost causation is more accurately captured by including a wider range of data points, rather than being unduly influenced by potential short-term fluctuations (Company Brief at 551).

Regarding the use of AMI data, the Company emphasizes that such data will only be appropriate for use in developing allocators once the AMI rollout is substantially complete (Company Brief at 551-552). The Company stresses the importance of having a statistically valid sample, which may not be achievable until the AMI system is fully implemented (Company Brief at 552). Thus, the Company argues that premature reliance on AMI data could lead to inaccurate and unreliable allocators (Company Brief at 552).

The Company opposes TEC and PowerOptions' argument that using a nine-year period for developing demand allocators is inappropriate (Company Brief at 552). The Company criticizes TEC and PowerOptions' assertion that the customer usage patterns are changing too rapidly to rely on such data, claiming this assertion is not substantiated by evidence (Company Brief at 552). The Company maintains that a longer data period is necessary to account for anomalies or non-recurring events and to ensure that demand allocators are based on a more representative and stable set of data (Company Brief at 552). Moreover, the Company contends that abrupt changes in demand allocators, which could result from using only one year of data, may not accurately reflect actual customer usage patterns (Company Brief at 552-553).

Furthermore, the Company challenges TEC and PowerOptions' reliance on Section 94*I* as a safeguard against non-representative data (Company Brief at 553). The Company argues that obtaining representative data is crucial for accurately determining costs, independent of the revenue allocation and rate design guardrails provided by Section 94*I* (Company Brief at 553).

The Company also criticizes both the Attorney General's and TEC and PowerOptions' proposals for lacking sufficient rationale to justify arbitrarily limiting the data period (Company Brief at 551). Therefore, the Company urges the Department to reject the Attorney General's recommendation to shorten the period for the ACOSS model (Company Reply Brief at 88). Instead, National Grid recommends that the Department allow the Company to utilize a fuller and more comprehensive data range, up to ten years, to ensure accurate and stable demand allocators (Company Reply Brief at 88).

3. Analysis and Findings

The Department requires that cost allocation methods be driven by cost-causation principles. D.P.U. 17-170, at 318; D.P.U. 11-01/D.P.U. 11-02, at 320; D.P.U. 10-114, at 187; D.P.U. 10-55, at 534. The Company directly assigned or allocated, as appropriate, each element of its revenue requirement to each rate class to establish rates that provide it with an opportunity to recover its costs and earn an appropriate return on its investments (Exh. NG-PP-1, at 6). The Company appropriately functionalized and classified costs as the first and second steps in its cost allocation process (Exh. NG-PP-1, at 6). The Company states that the allocator assignments in this case are the same as those used in D.P.U. 09-39, D.P.U. 15-155, and D.P.U. 18-150 (Exh. NG-PP-1, at 7). For the five demand allocators, however, rather than use a single year of data as in previous base distribution rate cases, the Company calculated the values to reflect averages over the nine-year timeframe of April 2014 through March 2023 (Exhs. NG-PP-1, at 14; NG-PP-3O (Rev. 4); NG-PP-3P (Rev. 4); and NG-PP-3Q (Rev. 4)). Intervenors expressed concern with this modification and urge the Department to require the Company to modernize its ACOSS in future base distribution rate cases (Attorney General Brief at 124-130; Attorney General Reply Brief at 39; TEC and PowerOptions Brief at 6-8; TEC and PowerOptions Reply Brief at 3).

The Department finds that in the instant proceeding, the Company's use of averages of nine years of historical data to be reasonable for development of the demand allocators used in its ACOSS. Nonetheless, as rate structure and rate design are addressed more broadly in the future to better reflect the Commonwealth's climate goals and contribute to the GHG emissions reduction targets, the Department finds it imperative that cost allocation methods be similarly reviewed to ensure they produce results that reflect the rapidly evolving industry. While the Department relies on a historical test year, it is important that we continue to consider the appropriateness of ACOSS results on the rate year. Therefore, the Department directs all EDCs to investigate the appropriateness of time ranges, sample sizes, and methods used to develop all ACOSS allocators, including those suggested by the Attorney General and TEC and PowerOptions, related to demand allocators, and to report on these efforts as part of the initial filings in their next base distribution rate cases. Finally, the Department directs the Company to provide an updated ACOSS, Exhibit NG-PP-2, as part of its compliance filing that reflects the final approved revenue requirement in this Order.

The Department also finds that after the cost allocation to rate classes in the ACOSS, the Company appropriately reallocated revenues between rate classes to ensure compliance with Section 94*I*, which requires that no rate class experience an increase in revenue requirement in excess of ten percent of total current revenues (Exh. NG-PP-4, at 1-3 (Rev. 4)). Similarly, the Company demonstrated compliance with the Department's rate continuity goal by ensuring that increases were less than two times (or 200 percent) of the overall average base distribution revenue increase (Exh. NG-PP-4, at 3 (Rev. 4)). Therefore, the Department directs the Company to provide in its compliance filing an updated version of Exhibit NG-PP-4, as illustrated in Schedule 10 below, that demonstrates the calculation of the target base distribution revenues for each rate class based on the results of the final revenue requirement approved in this Order.

C. Residential Electrification Rate

1. Introduction

Pursuant to G.L. c. 21N, the Secretary of the Executive Office of Energy and Environmental Affairs adopted a statewide GHG emissions limit and sector-specific sublimits for 2050. Executive Office of Energy and Environmental Affairs, Determination of Statewide Greenhouse Gas Emissions Limit and Sector-Specific Sublimits for 2050 (December 21, 2022). The Secretary set a sublimit of 95 percent below 1990 emissions levels by 2050 for the residential heating and cooling sector and stated that the Commonwealth's dominant strategy for building decarbonization is conversion to electrification. Executive Office of Energy and Environmental Affairs, Determination of Statewide Greenhouse Gas Emissions Limit and Sector-Specific Sublimits for 2050, at 1, 3 (December 21, 2022).

The Company states that the Commonwealth's electrification and clean energy goals will necessitate increased levels of customer investment in building retrofits and new technologies, such as heat pumps, to replace traditional fossil fuel-fired heating systems, as well changes to rate design to address barriers to electrification affecting residential customers (Exh. NG-CP-1, at 53). In particular, the Company states that its AMI deployment plan is expected to be completed in late 2027 and will enable implementation of time-varying and demand-based rate designs for residential customers that will send efficient, grid-beneficial price signals, reduce operating costs of electric heat and EV charging, and improve overall fairness across customers and their end uses (Exh. NG-CP-1, at 54).

Currently, the Company's residential customers are billed: (1) a fixed monthly customer charge that is lower than the embedded customer charge; and (2) a variable usage charge, based on kWhs of electricity consumed, that is higher than the variable cost for delivery service (Exh. NG-CP-1, at 53-54). This type of rate design can result in affordability barriers to increased electrification because customers with high electricity consumption and low non-coincident and coincident peak demands often pay more than the cost to serve them, which potentially results in uneconomic and prohibitively high operating costs of heating equipment the sole source of power for which is electricity and other high-electric-throughput beneficial technologies (Exh. NG-CP-1, at 54). As a first step to increase residential electrification, the Company submitted in this proceeding an "Electrification Pricing" proposal to address affordability and cost-causation concerns related to electrification (Exh. NG-CP-1, at 53-54). The Company states that it recognizes that the benefits of immediate action on rate design may not outweigh the inherent limitations, and if the Department does not approve its Electrification Pricing proposal, the Company would fully support a Department decision to postpone action on rate design in this base distribution rate case until advanced rate design has been investigated in a separate proceeding and can be more precisely implemented with AMI (Exh. NG-CP-Rebuttal-1, at 42).

In developing its Electrification Pricing proposal, the Company assessed four alternatives: (1) a pricing option offered only to customers with heat pumps; (2) a rate-adjacent pricing discount offered only to customers with heat pumps; (3) a pricing option available to all residential customers; and (4) not filing an Electrification Pricing proposal in this proceeding (Exh. NG-CP-Rebuttal-1, at 43). The Company states that it ruled out a heat-pump specific pricing option as antithetical to the principles of rate design because distribution system costs are not driven by a customer's specific end use (Exh. NG-CP-Rebuttal-1, at 43). The Company further states that such a pricing option would not help other customers who also overpay relative to their contribution to system costs under high volumetric rates, and that technology-specific rates can be confusing to customers, especially over the long term (Exh. NG-CP-Rebuttal-1, at 44). Regarding a rate-adjacent discount, the Company states that determining the appropriate discount as well as whether the discount should vary based on heat-pump technology and configuration would be contentious and possibly confusing (Exh. NG-CP-Rebuttal-1, at 44).

National Grid states that after ruling out the first two alternatives, it was left with a choice of proposing a pricing option open to all residential customers or doing nothing in this proceeding (Exh. NG-CP-Rebuttal-1, at 44). The Company states that it decided to submit a proposed rate design that it considered a first step toward moving away from volumetric delivery charges to begin to align revenue from customers with higher volumetric usage, such as heat electrification technologies (Exh. NG-CP-Rebuttal-1, at 44-45). The Company acknowledges that its proposal is not perfect and may pose risks the Department determines to be unacceptable (Exh. NG-CP-Rebuttal-1, at 45). National Grid submits, however, that its Electrification Pricing option reasonably represents a movement toward more cost-reflective and fair rate design compared to volumetric delivery charges (Exh. NG-CP-Rebuttal-1, at 45). The Company also states that it is open to continuing to discuss programmatic solutions to support electrification outside of rates (Exh. NG-CP-Rebuttal-1, at 44). Further, National Grid notes that if the Department determines that immediate action is necessary to address the operating costs for heat-pump customers, and as such a technology-specific solution is required or appropriate, then the Company would support a rate-adjacent discount program for customers with heat pumps (Exh. NG-CP-Rebuttal-1, at 46; Tr. 1, at 179-180; Tr. 3, at 463-466; Tr. 12, at 1485).

2. Company's Electrification Pricing Option

National Grid proposes an Electrification Pricing option for Rate R-1 customers that replaces the volumetric base distribution charge with a monthly fixed base distribution charge, but retains all other applicable Rate R-1 charges, including the customer charge (Exh. NG-CP-1, at 55). The Company proposes for the new rate to be open to all Rate R-1 customers on an opt-in basis (Exh. NG-CP-1, at 55). The Company contends that it designed the proposed fixed distribution charge by converting the target residential base distribution revenue from dollars per kWh to dollars per bill (Exhs. NG-CP-1, at 56; NG-PP-1, at 28; NG-PP-6, at 3 (Rev. 4)). National Grid proposes a $37.68 fixed monthly distribution charge for the Electrification Pricing option (Exhs. NG-CP-1, at 44; NG-PP-1, at 28; NG-PP-6, at 2-3 (Rev. 4)).

The Company states that residential customers with average volumetric usage higher than the average residential customer use of 574 kWh per month will experience meaningful, but modest bill savings as the per-kWh base distribution rate constitutes 19 percent of the total volumetric charge (Exh. NG-CP-1, at 56-57).[227] The Company maintains that for a customer using 700 kWh per month, bill savings would be approximately three percent under the Electrification Pricing option (Exh. NG-CP-1, at 58). Bill savings for customers using approximately 1,107 kWh per month, which is the average residential customer usage plus a three-ton air source heat pump, would be approximately nine percent; and bill savings for

[227] The volumetric charge also includes supply, transmission, and all surcharges and adjustment factors (Exh. NG-CP-1, at 56-57).

customers using approximately 1,462 kWh, which is the average residential usage plus a five-ton air source heat pump, would be approximately eleven percent (Exh. NG-CP-1, at 58).

The Company proposes to collect any revenue shortfall related to the proposed Electrification Pricing option through the revenue decoupling mechanism, which would allocate the shortfall to each rate class according to the appropriate distribution revenue allocators (Exh. NG-CP-1, at 58). The Company estimates that, assuming 100 percent of all customers with greater than average monthly use opt into the Electrification Pricing option, a Rate R-1 customer with usage of 600 kWh per month opting into the Electrification Pricing option will experience a bill increase of approximately 4.1 percent, or $108, to their annual bill, all else equal (Exh. NG-CP-1, at 58-59).

3. Positions of the Parties

a. Attorney General

The Attorney General recommends that the Department reject National Grid's proposed Electrification Pricing option (Attorney General Brief at 139). The Attorney General recognizes the Company's efforts to support the Commonwealth's electrification and clean energy goals, but she asserts that the Company has not demonstrated that its proposed Electrification Pricing option is reasonable or that it balances competing interests appropriately (Attorney General Brief at 140). The Attorney General further maintains that the Company has not demonstrated that the proposed Electrification Pricing option will provide support for the Commonwealth's conservation, energy efficiency, and electrification goals, nor does it send appropriate price signals for customers to decrease their load during the most expensive electricity cost times of the day to delay or minimize investment costs (Attorney General Brief at 141, citing Exh. AG-RNCP-1, at 39, 41).

The Attorney General argues that the Company's proposed Electrification Pricing option is not designed to target policy goals, such as supporting electrification technology adoption (Attorney General Brief at 142). The Attorney General also contends that the Company's proposal is an effort to start moving away from volumetric charges (Attorney General Brief at 142, citing Exh. NG-CP-1, at 59; Tr. 1, at 189). Further, the Attorney General asserts that the Company has not tailored the proposed rate to its own stated goal to support adoption of heat electrification technologies (Attorney General Brief at 142). The Attorney General maintains that if approved, the rate will remove some of the financial incentives for residential ratepayers to conserve energy and to pursue energy efficiency investments (Attorney General Brief at 142, citing Exh. AG-RNCP-1, at 45-46). Further, the Attorney General contends that the rate does not target customers who have installed heat pumps, but rather provides benefits to all customers with monthly consumption above 574 kWh (Attorney General Brief at 143).

In addition, the Attorney General argues that the Company's proposed Electrification Pricing option is inequitable as it is only available to Rate R-1 customers, while all customers, including Rate R-2 customers, will contribute to funding the revenue shortfall through the revenue decoupling mechanism (Attorney General Brief at 143). The Attorney General maintains that this proposed approach will exacerbate the high energy burden experienced by low-income ratepayers (Attorney General Brief at 144).

The Attorney General also maintains that the Company projects significant revenue shortfalls from the proposed Electrification Pricing option, which may be underestimated

(Attorney General Brief at 144). Specifically, the Attorney General asserts that the Company estimates a revenue shortfall of $3.1 million, or $29 per year for each residential customer if 30 percent of Rate R-1 ratepayers with monthly consumption of 600 kWh or higher opt-into the rate, and an additional $3.30 per year if Rate R-2 customers were eligible to participate and 30 percent opted-in (Attorney General Brief at 144, citing RR-DPU-42). Further, the Attorney General argues that if 100 percent of customers who would benefit decide to opt-in, the revenue shortfall related to Rate R-1 participants would increase to $16.8 million, or $97.02 per year, and an additional $10.99 per year related to Rate R-2 participation (Attorney General Brief at 144, citing RR-DPU-42). The Attorney General contends that National Grid's 30 and 100 percent opt-in estimates may understate the revenue shortfall as the Company has not proposed an end date for the proposed rate (Attorney General Brief at 145).

The Attorney General also asserts that the Company's proposed Electrification Pricing option does not adequately consider possible increases to the summer peak and associated costs related to exacerbating existing system peaks (Attorney General Brief at 145). The Attorney General maintains that as the proposed option is not time-differentiated and there is no requirement that customers who enroll in the option also participate in load management programs, the rate may lead to increased summer peak demand and, in turn, to increases in distribution system costs (Attorney General Brief at 146).

The Attorney General recommends that if the Department approves a rate that incentivizes electrification, the rate should have a volumetric component, and a lower fixed charge component compared to that proposed by the Company (Attorney General Brief at 148). The Attorney General argues that an approach in which collection of primary distribution costs are removed from the fixed charge would provide a reasonable balance between support for electrification and heat-pump adoption, conservation, energy efficiency, and cost-shifting (Attorney General Brief at 148). The Attorney General's recommendation would result in a fixed charge of $13.24 in addition to the Company's proposed $11.00 customer charge, with the remaining revenue requirement being collected through a volumetric kWh rate that would be less than that for Rate R-1 customers (Attorney General Brief at 148-149, citing Exh. AG-RNCP-1, at 46-47).

Alternatively, the Attorney General recommends three modifications to the availability of the Electrification Pricing option if the proposal is approved by the Department. First, the Attorney General asserts that the Department should direct the Company to make the Electrification Pricing option available to Rate R-2 customers (Attorney General Brief at 149; Attorney General Reply Brief at 41-42). Second, the Attorney General recommends that the rate be available only to customers who have fully displaced all of their space heating appliances with heat pumps to ensure that any additional consumption would come primarily from heat pumps rather than other appliances (Attorney General Brief at 150). Third, the Attorney General asserts that because the Interagency Rates Working Group[228] is currently undergoing a substantial effort to develop concrete recommendations on rate design to support electrification, any approval of National Grid's proposed Electrification Pricing option should be on an interim basis (Attorney General Brief at 150-151). Further, the Attorney General requests that the

[228] The Interagency Rates Working Group was convened by DOER in partnership with the Executive Office of Energy and Environmental Affairs, the Massachusetts Clean Energy Center, and the Attorney General, to advance near- and long-term electric rate designs that align with the Commonwealth's decarbonization goals (DOER Brief at 46).

Department direct the Company to file a compliance filing in this proceeding after the proposed rate has been in effect for 18 months, including information regarding: (1) changes in pre-install and post-install energy use following heat-pump conversion including summer use for cooling; and (2) whether heat-pump conversions contribute to rising costs on the Company's system (Attorney General Brief at 151).

The Attorney General asserts that she supports DOER's recommendation, discussed below, to direct the Company to file a seasonally discounted heat-pump rate, but she urges two modifications: (1) it is approved on an interim basis; and (2) it is limited to customers with heat pump capacity-sized to heat the customer's entire home (Attorney General Reply Brief at 40). The Attorney General also recommends that the same reporting requirements applicable to Unitil's heat-pump rate be adopted in this proceeding (Attorney General Reply Brief at 41, citing D.P.U. 23-80/D.P.U. 23-81, at 408).[229]

b. DOER

DOER recommends the Department reject the Company's proposed Electrification Pricing option (DOER Brief at 23). DOER asserts that the Company's proposal is not well developed, and that the Company has made conflicting statements regarding the genesis and purpose of the proposed option (DOER Brief at 24). DOER also asserts that the Company's

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229 The Department directed Unitil to provide as part of its annual reconciliation filing the number of customers opting into (and off) the new tariffs, twelve months of pre- and post-installation monthly kWh use, and monthly peak kW use, if possible. The Department also required the Company to include the number of customers, by rate class, opting into the heat-pump rate who received a rebate through the Mass Save program, as well as the number of customers who received a rebate through the Mass Save program but have not opted into the heat-pump rate. D.P.U. 23-80/D.P.U. 23-81, at 408.

proposed Electrification Pricing option will provide only modest benefits to participating customers, while creating upward pressure on volumetric rates of all customers (DOER Brief at 25). DOER further asserts that National Grid fails to recognize the deleterious bill impacts on participating customers, as the Company proposes to recover revenue deficiencies through the revenue decoupling mechanism and therefore participating customers will also experience increases in volumetric rates (DOER Brief at 26). DOER also contends that as proposed, the Electrification Pricing option inappropriately burdens low-income customers, as Rate R-2 customers are ineligible to opt-into the option without first switching to Rate R-1 (DOER Brief at 28, citing Exh. DOER 1-9, Att.).

DOER maintains that the proposed Electrification Pricing option does not support the Commonwealth's electrification goals as it is not restricted to customers with efficient electric technologies (DOER Brief at 27, citing Exh. AG-RNCP-1, at 47). DOER further argues that National Grid's proposal is inefficient as it fails to be cost-based and will not provide a rate structure that gradually allows consumers the opportunity to adjust their consumption patterns in preparation for future opportunities of time-varying rates (DOER Brief at 30). DOER maintains that the Company's assertion that a fixed charge represents a movement toward more cost-reflective rate design compared to volumetric charges is untrue because the fixed charge does not change based on an individual's demand, and therefore does not more accurately reflect a customer's contribution to demand-related costs (DOER Brief at 31-32).

DOER recommends that the Department direct the Company to incentivize equitable and efficient electrification through a reasonable, cost-efficient solution to mitigate the potential high bills associated with heat-pump implementation, similar to that approved for Unitil in

D.P.U. 23-80/D.P.U. 23-81 but with modifications (DOER Brief at 34-40; DOER Reply Brief at 2-3, citing D.P.U. 23-80/D.P.U. 23-81, at 407). DOER maintains that such a rate can minimize cost shifting and provide efficient price signals in the near- to medium-term (DOER Brief at 41). DOER also maintains that any rate designed to advance electrification must include low-income customers (DOER Brief at 43-44).

DOER asserts that as the Company's proposed volumetric rate is 45 percent lower than Unitil's, the price signal of a heat-pump rate design limited to the base distribution charge is diluted and insufficient to increase heating electrification (DOER Reply Brief at 3-4). DOER further asserts that if a heat-pump rate like Unitil's is applied to the Company without modification, overall energy costs would remain high and low-to-moderate income customers will likely continue to satisfy heating needs with gas (DOER Reply Brief at 4). Therefore, DOER recommends that the Department direct modifications to the Company's reconciling mechanisms to ensure sufficient financial incentives for heating electrification (DOER Reply Brief at 4). DOER also recommends that the Department direct the Company to conduct robust marketing, education, and outreach activities regarding the availability and benefit of DOER's proposed seasonally discounted heat-pump rate (DOER Brief at 45). Further, DOER recommends that the Department direct the Company to market its Off-Peak Charging Program to customers who enroll in an electrification rate to offset the impact of flexible loads from increasing peak load (DOER Brief at 46). Finally, DOER asserts that the Interagency Rates Working Group's forthcoming recommendations should not dissuade the Department from taking immediate action on a heat-pump rate option (DOER Brief at 46-47).

c. Low-Income Network

The Low-Income Network recommends that the Department reject the Company's proposed Electrification Pricing option (Low-Income Network Brief at 2; Low-Income Network Reply Brief at 6). The Low-Income Network asserts that the Company's proposed Electrification Pricing option does not encourage policy-based electrification for GHG emissions reductions, but rather it is a rate design based on a particular notion of utility economics that above-average-consumption consumers deserve a lower average rate per kWh no matter the nature of their consumption (Low-Income Network Brief at 8). The Low-Income Network argues that while National Grid on brief asserts that the goal of the Electrification Pricing option is to support electrification, this assertion is contradicted by a Company statement in evidentiary hearings that "really the primary objective is to begin sort of correcting rate design" (Low-Income Network Reply Brief at 4, citing Company Brief at 538; Tr. 1, at 207). Finally, the Low-Income Network asserts that rate design proposals like the Electrification Pricing option are best suited for consideration in a statewide proceeding such as the ongoing energy burden investigation in D.P.U. 24-15 (Low-Income Network Brief at 17; Low-Income Network Reply Brief at 6). Nevertheless, the Low-Income Network supports the Company's position that if the Department determines that immediate action is necessary to reduce operating costs for heat-pump customers, it would support a rate-adjacent discount program for customers with heat pumps (Low-Income Reply Brief at 5, citing Company Brief at 477).

d. CLF, EDF, and Acadia Center

CLF, EDF, and Acadia Center recommend that the Department reject the Company's proposed Electrification Pricing option (CLF Brief at 9; EDF Brief at 34; Acadia Center Brief at 7). CLF, EDF, and Acadia Center maintain that the Company's proposal is inequitable, does not accurately reflect the cost of electricity, and does not promote beneficial electrification (CLF Brief at 9; EDF Brief at 34-35, citing Exh. EDF-CLF-JRC-1, at 70; Acadia Center Brief at 9-10).

CLF asserts that since the Company's recovery of lost revenue from the Electrification Pricing option could impact customers on the low-income discount rate, the proposal's equity impacts are of serious concern (CLF Brief at 10). EDF maintains that the Electrification Pricing option makes a wealth transfer likely where lower usage customers subsidize affluent customers with higher-than-average electricity usage (EDF Brief at 35, citing Exh. EDF-CLF-JRC-1, at 70).

CLF, EDF, and Acadia Center assert that the Electrification Pricing option does not properly convey the cost of electricity consumption to customers and does not adequately provide price signals for energy efficiency and conservation (CLF Brief at 11, citing Exh. DOER-MDW-1, at 9; EDF Brief at 36-37, citing Tr. 1, at 190-201; Acadia Center Brief at 9). CLF also maintains that the Company has not demonstrated that its Electrification Pricing option will reduce GHG emissions (CLF Brief at 10). Acadia Center further contends that the proposal is contrary to the Commonwealth's emissions reduction goals and could undermine their achievement as it is available to all Rate R-1 customers, not only those who have installed heat pumps (Acadia Brief at 10). EDF and Acadia Center also assert that the fixed charge design of the proposed rate removes an incentive for inefficient customers to upgrade to more efficient electric heating systems or conserve energy (Acadia Center Brief at 10; EDF Brief at 35, citing Exh. EDF-CLF-JRC-1, at 72).

CLF, EDF, and Acadia Center recommend that the Department direct the Company to propose a heat-pump rate that closely aligns with Unitil's recently-approved rate within six months of the Department's Order in the instant proceeding as a compliance filing (EDF Brief at 39, citing Exh. EDF-CLF-JRC-1 at 74; CLF, EDF, Acadia Center Reply Brief at 12). CLF, EDF, and Acadia Center assert that the Company should conduct stakeholder outreach to incorporate feedback at least six weeks prior to filing its proposal, and the compliance filing should be subject to a brief adjudicatory process (CLF, EDF, Acadia Center Reply Brief at 12).

e. MEDA

MEDA argues that the Company's proposed Electrification Pricing option rewards customers with above-average usage rather than target heat-pump customers (MEDA Reply Brief at 28). MEDA contends that it supports the arguments of the Attorney General and DOER regarding the negative impact of the Electrification Pricing option on low-income customers, including the fact that Rate R-2 customers are ineligible to opt-into the rate (MEDA Reply Brief at 28).

f. TEC and PowerOptions

TEC and PowerOptions recommend that the Department reject the Company's Electrification Pricing option because it fails to uphold the Department's cost-causation principles and is unlikely to advance electrification (TEC and PowerOptions Brief at 10). Specifically, TEC and PowerOptions oppose the proposal to recover any revenue shortfall related to customers that opt into the rate from all other customers through the revenue decoupling mechanism, and they assert that this amounts to an unlawful cross subsidy that violates cost-causation principles (TEC and PowerOptions Brief at 11, citing Exhs. NG-CP-1, at 58; AG-RNCP-1, at 39-42). TEC and PowerOptions further argue that multiple other intervenors, including the Attorney General, DOER, CLF, and EDF, demonstrate that the proposal will not help prepare customers for time-of-use rates, will not provide the appropriate price signals to customers, and creates equity concerns (TEC and PowerOptions Brief at 11, citing Exhs. AG-RNCP-1, at 39-42, 46, 66; DOER-MDW-1, at 8-11, 19; EDF-CLF-JRC-1, at 71-74; TEC/PO-JDB/AN-1, at 40).

g. SEIA

SEIA maintains that the Department should reject the Company's proposed Electrification Pricing option for four reasons. First, SEIA contends that the proposal would send inefficient price signals and cause concerning cost shifts (SEIA Brief at 11). SEIA argues that the proposal will incorrectly convey that there is no cost to consumption during peak periods, which threatens to increase demand during such times (SEIA Brief at 11). SEIA further maintains that the proposal will reduce incentives to conserve electricity, will shift costs from high-usage residential customers to other customers without demonstrating that doing so reflects cost causation, and will completely sever the connection between consumption and cost, in contrast to the Department's goal of efficiency in designing rates (SEIA Brief at 11-13, citing Exhs. AG-RNCP-1, at 41-42; DOER-MDW-1, at 10-11, 15).

Second, SEIA argues that the proposal would hinder rather than advance the Commonwealth's emission reduction goals (SEIA Brief at 16-19). SEIA asserts that the Company's proposal is misaligned with the Commonwealth's emissions goals because it would benefit all customers with higher-than-average usage without incentivizing beneficial behaviors or technologies (SEIA Brief at 16-19, citing Exh. DOER-MDW-1, at 11; Tr. 1, at 135-136; 208-209; Tr. 3, at 501-502).

Third, SEIA maintains that the proposal would confuse customers, impeding the transition to more efficient and effective rate designs in the future (SEIA Brief at 18). SEIA contends that the proposal is being made in advance of the Company's expectation to implement dynamic and structured rates to send precise price signals and, as such, would frustrate goals of simplicity and continuity because it would "result in zig-zagging rate designs for residential customers over the next few years, the 'Electrification Pricing' proposal constituting an initial 'zig' that runs in exactly the opposite direction from National Grid's long-term plan to 'zag'" (SEIA Brief at 18; Tr. 1, at 204-206).

Finally, SEIA argues that the proposal is inequitable as it would reduce the distribution charges of customers with higher-than-average usage, who are possibly more affluent customers, and recover revenue associated with that reduction from all other customers, including low-income customers (SEIA Brief at 20, citing Exh. DOER-MDW-1, at 18).

h. Company

National Grid maintains that the goal of its proposed Electrification Pricing option is to support electrification in the Company's service territory, to provide customers with options for affordability and bill stability, and to serve as a first step toward a more cost-reflective rate design because the costs will not vary with usage (Company Brief at 538, citing Exh. NG-PP-1, at 25-26). The Company further contends that this first step toward more cost-reflective rate design is necessary to enable widespread electrification, to increase electric system investments, and to transition from the gas network (Company Reply Brief at 83, citing Exhs. NG-CP-1, at 54-56; NG-PP-1, at 25-26; DOER 3-8; Tr. 12, at 1488-1489).

The Company maintains that the concept of a seasonal heat-pump rate discount similar to the one recently approved in D.P.U. 23-80/D.P.U. 23-81 is a solution to the fundamentally different and narrower objective of providing a financial incentive for near-term heat-pump adoption (Company Reply Brief at 83). National Grid requests that if the Department accepts intervenor recommendations for a seasonal discount for customers with specific technologies, the purpose and objectives of the rate option should be made clear, because they are not equivalent to the purpose and objectives of the Company's Electrification Pricing option (Company Reply Brief at 83). In particular, the Company maintains that the seasonal discount should be referred to as a program or seasonal rate discount rather than a rate or rate design, and program costs should be recovered in surcharges that are transparent to customers (Company Reply Brief at 84). The Company asserts that this distinction is important because mixing terminology has led to a state of confusion among stakeholders on what constitutes rate design reflecting cost-causation principles to achieve the specific objectives of rate design, and what is an explicit subsidy for the purpose of incentivizing adoption of specific technologies (Company Reply Brief at 84-85). The Company further maintains that the Department should establish clear program parameters, and that the existence of a technology-specific seasonal rate discount program should not interfere with continued efforts toward cost-reflective rate design to enable the energy transition (Company Reply Brief at 85).

With respect to the heat-pump rate approved in D.P.U. 23-80/D.P.U. 23-81, the Company maintains that it does not disagree with the premise of the methodology for its calculation, but cautions that distribution costs are not driven by season, but rather by peak demands (Company Reply Brief at 85). National Grid asserts that the duration of a program designed to encourage increased winter use may accelerate the electric distribution system's movement toward a winter peak, and therefore any such program should be limited to five years, subject to reevaluation in the Company's next base distribution rate case or other relevant Department proceeding (Company Reply Brief at 85-86).

4. Analysis and Findings

General Laws c. 164, § 141 states in pertinent part that in all decisions or actions regarding rate designs, the Department shall consider the impacts of such actions on the reduction of GHG emissions as mandated by G.L. c. 21N to reduce energy use and efforts to increase efficiency and encourage non-emitting renewable sources of energy. The Department finds the Company's proposed Electrification Pricing option addresses neither of these mandates; the proposal dissociates base distribution costs from usage, thereby reducing the incentive to conserve energy or increase efficiency relative to customers paying variable base distribution rates (Tr. 1, at 201). Further, the Company has not proposed to limit enrollment to customers who have adopted beneficial electrification technologies and, as such, the proposal does not support increased efficiency (Exh. NG-CP-Rebuttal-1, at 44).

In D.P.U. 23-80/D.P.U. 23-81, the Department expressed support for customer conversion to electrified and decarbonized heating technologies, including heat pumps, consistent with the Commonwealth's transition to clean energy. D.P.U. 23-80/D.P.U. 23-81, at 406; See, e.g., Three-Year Energy Efficiency Plans for 2022 through 2024, D.P.U. 21-120 through D.P.U. 21-129, at 230-231 (2022) (discussing statewide effort to encourage heat pumps). The Department further stated that we expect Massachusetts utilities to present proposals that appropriately balance the resulting rate impact with the intended benefits associated with heat pump use. D.P.U. 23-80/D.P.U. 23-81, at 406. As such, we approved Unitil's request for heat-pump rates, having found that they were a reasonable, cost-efficient solution to mitigate the potential high bills associated with heat-pump implementation faced by residential and low-income customers within the context of current rate structures, while maintaining a rate structure that accurately reflects the cost to serve customers during this stage of electrification. D.P.U. 23-80/D.P.U. 23-81, at 407.

In the instant proceeding, the Company asserts that the goal of its proposed Electrification Pricing option is to support electrification in the Company's service territory, to provide customers with options for affordability and bill stability, and to serve as a first step toward a more cost-reflective rate design because the costs will not vary with usage (Company Brief at 538, citing Exh. NG-PP-1, at 25-26). The Company maintains that its proposal is more broadly and holistically an incremental effort to advance rate design from its present state to a desired outcome over the long term (Company Reply Brief at 84). The Company states that distribution system costs are largely fixed and that its proposed rate represents an effort to lay the groundwork to enable electrification by moving away from volumetric charges (Exh. NG-CP-1, at 54-55; Tr. 1, at 207-208).

While the Department appreciates the Company's attempt to move toward more cost-reflective rate design in the instant case, we find it premature and inefficient to remove all variability from base distribution rates, as demand costs are not entirely fixed (Tr. 1, at 192-184). Rate design changes of such proposed magnitude require significant examination and discussion, and the larger issue of how to utilize rate design as a tool to assist in reaching the Commonwealth's climate goals is better suited for statewide discussion in a different proceeding.

The Department finds that the Company's proposal, made in advance of dynamic rates that will send precise price signals, would frustrate goals of simplicity and continuity.

Numerous intervenors recommended the Department direct the Company to implement a rate offering similar to Unitil's heat-pump rate, while the Company cautions against this recommendation for various reasons discussed above (Attorney General Reply Brief at 40-41; DOER Brief at 34-40; DOER Reply Brief at 2-3; CLF, EDF, Acadia Center Reply Brief at 12; Company Reply Brief at 84-85). The Department finds that a heat-pump rate similar to that approved for Unitil, rather than providing a financial incentive, attempts to mitigate a disincentive for certain types of customers inherent in traditional residential rate design (see Exh. NG-CP-1, at 53-54; Tr. 1, at 135). The Department is not persuaded that such a heat-pump rate constitutes an explicit subsidy, as there is no explicit grant or gift of monies from other rate classes to those taking service under the heat-pump rates to enable the rate offering. D.P.U. 23-80/D.P.U. 23-81, at 399, 406-407. Additionally, the Department finds that a heat pump rate similar to that approved for Unitil reflects the cost to serve a certain kind of customer and is reflective of cost-causation principles, as the heat-pump rate is a direct function of Unitil's cost of service, based on the company's approved revenue requirement associated with the residential rate class, and calculated to reflect typical usage associated with heat-pump customers. D.P.U. 23-80/D.P.U. 23-81, at 399. Finally, the Department finds that a rate structure such as that used to develop Unitil's heat-pump rate adequately addresses the goals articulated in G.L. c. 164, § 141, because the rate removes a disincentive for customers to accept beneficial electrification technology and retains the incentive to conserve energy. Thus, rate design can abide by the principles of cost causation while simultaneously addressing policy goals, such as removing barriers to electrification technology adoption.

Based on the above considerations, the Department rejects National Grid's Electrification Pricing option, and instead directs the Company to implement a heat-pump rate similar to that recently approved in D.P.U. 23-80/D.P.U. 23-81.[230] Specifically, the Department directs the Company to submit for approval a heat-pump rate tariff eligible to all Rate R-1 and Rate R-2 customers who install heat pumps for space heating in all or part of their home, that adjusts the base distribution kWh charge[231] during the winter months to reflect operation of heat pumps for space heating.[232, 233] The Department declines to direct the Company to limit this offering to customers with heat pumps capacity-sized to heat the customer's entire home as recommended by the Attorney General, as the Department finds that at this time, any beneficial electrification should be encouraged. The rate shall be an interim offering as recommended by the Attorney General, available until the Company's next base distribution rate case, or until an alternative is

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230 By limiting the offering to customers with heat pumps, the Department expects there to be a reduced chance of significant revenue shortfalls relative to the proposed Electrification Pricing option through the revenue decoupling mechanism.

231 Because the approved rate contains a volumetric base distribution charge, and the only fixed component is the customer charge, the Attorney General's recommendation to remove primary distribution costs from the proposed monthly fixed charge is now moot.

232 In reaching this finding, the Department determines that the Attorney General's recommended modifications to include Rate R-2 customers has been incorporated into the approved rate design.

233 Proposed tariffs should be consistent with the Company's response to Record Request DPU-44, which amended the Company's proposed Rate R-1 tariffs. The Department notes that the response to Record Request DPU-45 incorrectly assumed that the Company had already proposed an Electrification Pricing option in its proposed Rate R-2 tariffs.

approved by the Department. As part of its compliance filing, the Company shall provide (1) the time required to implement the heat-pump rate offering, (2) the tracking and reporting requirements articulated in D.P.U. 23-80/D.P.U. 23-81, at 408, and (3) a description of the outreach and marketing efforts the Company will undertake. The Department strongly encourages the Company to implement the heat-pump rate expeditiously to ensure that residential customers can experience the benefit during the next heating season. The Company shall further explain how it will track potential increases in summer peak demand due to heat-pump penetration, as recommended by the Attorney General (Attorney General Brief at 146, 151). Compliance with these directives shall be filed with the Department no later than 45 days following the issuance of this Order.

The Department finds that given its directive to provide the same tracking and reporting requirements as articulated in D.P.U. 23-80/D.P.U. 23-81, at 408, a compliance filing after the rate has been in effect for 18 months as recommended by the Attorney General is not required. Further, the Department declines to direct the Company to modify its reconciling mechanisms as recommended by DOER (DOER Reply Brief at 4). The Department finds that since reconciling mechanism rates are adjusted annually, and can be positive or negative, further investigation is required to analyze the range of potential bill impacts, as well as additional annual administrative costs, that would result from such a modification.

D. Other Issues

1. Coincident Peak Transmission Billing

a. Introduction

In their prefiled joint testimony, TEC and PowerOptions recommend that the Department direct the Company to implement coincident peak billing for transmission rates on an opt-in basis for large C&I customers (Exh. TEC/PO-JDB/AN-1, at 9). TEC and PowerOptions state that coincident peak transmission billing should be available to customers that have onsite DG, energy storage, or highly flexible loads (Exh. TEC/PO-JDB/AN-1, at 16). TEC and PowerOptions request that opt-in entry be limited to customers with peak demands of greater than 1,000 kW and that opt-in require a minimum commitment of twelve months (Exh. TEC/PO-JDB/AN-1, at 16). TEC and PowerOptions state that they do not expect the universe of eligible customers to be large (Exh. TEC/PO-JDB/AN-Rebuttal-1, at 5).

TEC and PowerOptions define coincident peak billing for transmission service as a method where a C&I customer is billed for transmission service based on its contribution to the monthly peak hour for the ISO New England Inc. ("ISO-NE") regional transmission system that serves the Company, which is the same as how EDCs are billed for Regional Network Service (Exh. TEC/PO-JDB/AN-1, at 9). TEC and PowerOptions note that large C&I customers in the NSTAR Electric service territory are able to be billed for transmission based on their loads coincident with the Regional Network Service transmission system peak (Exh. TEC/PO-JDB/AN-1, at 10).

TEC and PowerOptions state that coincident peak billing for transmission service is aligned with the goals of the 2022 Clean Energy Act and is best suited for Department consideration in base distribution rate proceedings (Exh. TEC/PO-JDB/AN-1, at 15). TEC and PowerOptions further state that the Company's current transmission rate design does not offer efficient price signals, as it severs the link between cost-causing activity and the price signal for customers (Exh. TEC/PO-JDB/AN-1, at 16). Finally, TEC and PowerOptions state that coincident peak transmission billing is a tool that the Company can deploy to help large C&I customers manage their costs and help improve system efficiency by flattening peak load events (Exh. TEC/PO-JDB/AN-1, at 16).

b. Positions of the Parties

i. Attorney General

The Attorney General acknowledges that the issue of coincident peak transmission billing should be explored, but she recommends that the proposal be rejected in the instant proceeding based on additional costs that the Company would incur to implement such billing (Attorney General Reply Brief at 42). The Attorney General instead recommends that the Company evaluate a coincident peak transmission billing option, as well as associated costs, prior to its next base distribution rate case proceeding (Attorney General Reply Brief at 42). The Attorney General also asserts that attention should be paid to ensuring transmission costs can be mitigated or reduced by participants, rather than shifted to non-participants (Attorney General Reply Brief at 42).

ii. TEC and PowerOptions

TEC and PowerOptions contend that an opt-in coincident peak billing rate for transmission can help accelerate storage adoption and deliver reliable peak load reductions and would be consistent with the Commonwealth's decarbonization policies (TEC and PowerOptions

Brief at 2). TEC and PowerOptions assert that billing for coincident peak transmission service can be done manually at a low cost relative to the value such billing could provide to the system until it can be automated (TEC and PowerOptions Brief at 3). TEC and PowerOptions explain that the Company has indicated that it issues manual invoices to a limited number of customers that are participating in the SMART program at an estimated cost of $153.60 per bill (TEC and PowerOptions Brief at 3, citing RR-TEC-2; TEC and PowerOptions Reply Brief at 2). Nonetheless, TEC and PowerOptions recommend a monthly fee of $500 per bill to cover the Company's administrative and analyst costs for a manual billing program and requests that the Department require this billing option to be available within six months of the date for this Order (TEC and PowerOptions Brief at 3-4).

iii. Company

The Company recommends that the Department reject TEC and PowerOptions' recommendation to implement coincident peak transmission billing for large C&I customers (Company Brief at 556; Company Reply Brief at 90). While the Company agrees with giving customers the option to pay for transmission service based on their contribution to system peak, National Grid also expresses concern regarding the costs and changes required to the Company's billing system as well as the Transmission Service Cost Adjustment Provision to implement this transmission service billing option (Company Reply Brief at 90, citing Exh. NG-PP-Rebuttal-1, at 17). The Company asserts that instead, this issue should be studied along with other rate design options, in conjunction with the AMI rollout (Company Reply Brief at 90, citing Exh. NG-PP-Rebuttal-1, at 17).

c. Analysis and Findings

In NSTAR Electric's most recent base distribution rate case, the Department approved the expansion of coincident peak transmission billing for large C&I customers. D.P.U. 22-22, at 461. The Department determined 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. 22-22, at 460; D.P.U. 17-05-B at 212; D.P.U. 10-70-B at 6. In the instant case, the Department is persuaded that an opt-in coincident peak billing rate for transmission can help accelerate storage adoption and deliver load reductions during peak times (Exh. TEC/PO-JDB/AN-1, at 14-16). Therefore, such a rate design meets the goal of efficiency and helps supports the Commonwealth's decarbonization policies. Accordingly, the Department directs the Company to implement a coincident peak billing option for transmission service on an opt-in basis for large C&I customers.

The Department also recognizes the Attorney General's and the Company's concern regarding the costs to implement such a pricing option (Company Reply Brief at 90, citing Exh. NG-PP-Rebuttal-1, at 17; Attorney General Reply Brief at 42). The Company has indicated that it issues manual invoices, on an interim basis, to a limited number of customers participating in the SMART program at an estimated cost of $153.60 per bill (RR-TEC-2). Therefore, we find that it is reasonable for National Grid to assess a charge of $155 per bill for each customer opting into the coincident peak billing option based on the Company's estimated cost to manually issue invoices to the limited subset of customers participating in the SMART program that are not yet able to receive automated bills.

2. Meter Totalization Policies

a. Introduction

TEC and PowerOptions define meter totalization as a process in which multiple time synchronized meters that are usually located on the same property or contiguous facility are summed into one interval meter dataset for billing (Exh. TEC/PO-JDB/AN-1, at 17). TEC and PowerOptions state that while not available to new customers, the Company previously offered meter totalization to customers taking service under Rates G-2 and G-3, and there are currently 104 customers billed with meter totalization (Exh. TEC/PO-JDB/AN-1, at 17, citing Exh. TEC 3-1).

TEC and PowerOptions recommend that new language be included in the Company's Distribution Service Terms and Conditions tariff to allow for continued meter totalization in the event a current customer's meters become disaggregated (Exh. TEC/PO-JDB/AN-Surrebuttal-1, at 13-14, citing M.D.P.U. No. 1316, § 4.A). TEC and PowerOptions state that when projects that alter electric service arrangements happen in a manner that results in a disaggregation of electric meters, customers experience large and unexpected cost increases resulting from the loss of meter totalization (Exh. TEC/PO-JDB/AN-Surrebuttal-1, at 13). TEC and PowerOptions state that at present there are only oblique references to meter totalization in the Company's tariffs (Exh. TEC/PO-JDB/AN-Surrebuttal-1, at 14, citing Exh. TEC 4-2(c)).

b. Positions of the Parties

i. TEC and PowerOptions

TEC and PowerOptions assert that meter totalization is of high value to customers and they should be able to retain such an arrangement, even if electrical service upgrades or other construction projects trigger a disaggregation of a customer's meters (TEC and PowerOptions Brief at 13, citing Exh. TEC/PO-JDB/AN-Surrebuttal-1, at 14). TEC and PowerOptions maintain that many customers with meter totalization would be willing to pay documented and quantifiable costs as a condition of maintaining the arrangement after a construction project that would otherwise trigger a disaggregation of the customer's meters (TEC and PowerOptions Brief at 13; TEC and PowerOptions Reply Brief at 6-7).

ii. Company

The Company asserts that to provide clarity, it is open to documenting its policy applicable to current customers only that currently have a totalization scheme in place as long as there are no changes to the existing service or other triggering events (Company Reply Brief at 92). The Company maintains that such a policy would include customer requirements to maintain meter totalization, as well as examples of triggering events that would result in the removal of the totalization scheme from the customer's account (Company Reply Brief at 92-93). The Company asserts that it would make such policy available to its customers with existing meter totalization (Company Reply Brief at 93).

c. Analysis and Findings

In light of the parties' positions on this issue, the Department finds it reasonable for the Company to document its policies such that current customers have clarity regarding events that trigger meter disaggregation. Given that the Company is not changing any policy, but simply codifying an existing one, we find it is appropriate for the Company to offer amendments to the Terms and Conditions section of its tariffs to include its current meter totalization policies as part of its compliance filing in this Order.

3. Voltage Rate Proceeding

a. Introduction

TEC and PowerOptions state that the Company currently offers a per kW discount to customers who own their own transformers and take service at voltages greater than 2.4 kW (Exh. TEC/PO-JDB/AN-1, at 19, citing Exh. NG-PP-1, at 10). TEC and PowerOptions further state that customers who are metered at 2.4 kV or higher also receive a one percent discount on their bills (Exh. TEC/PO-JDB/AN-1, at 19, citing M.D.P.U. No. 1473). TEC and PowerOptions state that such customers taking service at primary voltage levels should not pay the same rates for distribution service as those taking service at secondary voltage levels (Exh. TEC/PO-JDB/AN-1, at 19).

TEC and PowerOptions explain that FERC accounts 364 through 367 detail costs associated with the mileage of overhead conductors and underground circuits required to operate the Company's distribution system and assert that this mileage is differentiated by voltage levels: secondary voltage, 5 kV, 15 kV, and 23 to 35 kV (Exh. TEC/PO-JDB/AN-1, at 20).[234] TEC and PowerOptions state that secondary voltage infrastructure, which is not used by customers receiving service at a higher voltage, comprises a large percentage of these FERC account categories, but there is no adjustment to rates to reflect the lower infrastructure requirements of a customer taking service at a higher voltage level (Exh. TEC/PO-JDB/AN-1, at 20). TEC and PowerOptions recommend that rate design and cost allocation for the Rate G-3 class differentiate

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234 FERC account 364 includes poles, towers, and fixtures; FERC account 365 includes overhead conductors and devices; and FERC accounts 366 and 367 include underground conduits (Exh. TEC/PO-JDB/AN-1, at 20).

between customers taking service above 13 kV with those taking service at lower voltages, to alleviate what TEC and PowerOptions consider to be an inequitable situation in which high voltage customers pay for portions of the distribution system that they do not use (Exh. TEC/PO-JDB/AN-1, at 20).

TEC and PowerOptions recommend that the Company's rates be altered to reflect the costs of infrastructure related to customers taking service at voltages above 13 kV and that these rates be implemented within one year of the Department's Order in this proceeding (Exh. TEC/PO-JDB/AN-Surrebuttal-1, at 12). In the alternative, TEC and PowerOptions recommend that the Department order the opening of a single-issue rate proceeding to investigate and implement voltage differentiated rates immediately following the conclusion of the instant proceeding (Exh. TEC/PO-JDB/AN-Surrebuttal-1, at 12).

b. Positions of the Parties

i. Attorney General

The Attorney General opposes changes to high voltage discounts (Attorney General Reply Brief at 43). The Attorney General instead recommends that the Department require the Company to analyze this issue prior to its next base distribution rate case to inform eliminating or reducing high-voltage credits to more accurately reflect the current state of the distribution system and associated costs (Attorney General Reply Brief at 43, citing Exhs. AG-RNCP-1, at 20-22 (Rev.); AG-RNCP-Surrebuttal-1, at 7-8).

ii. TEC and PowerOptions

TEC and PowerOptions assert that both parties and the Company agree that a study must be performed to quantify the differences in cost of service for C&I customers taking service above and below 13 kV (TEC and PowerOptions Brief at 9). TEC and PowerOptions maintain that it would be unreasonable to allow a known inequity in rates, and therefore the Department should not wait until the Company's next base distribution rate case to examine the issue and should instead order a separate single-issue rate proceeding following the conclusion of this instant proceeding (TEC and PowerOptions Brief at 9; TEC and PowerOptions Reply Brief at 5). TEC and PowerOptions argue that rates that reflect the actual costs of service for high voltage customers are important for their economic feasibility studies to determine how they can advance electrification, and in turn advance the Commonwealth's decarbonization goals (TEC and PowerOptions Reply Brief at 6).

iii. Company

The Company agrees that there should be a study to quantify the differences in the cost of service for customers taking service above and below 13 kV (Company Brief at 555; Company Reply Brief at 90). Nonetheless, the Company contends that implementing voltage-differentiated rates would require changes to its billing systems and recommends doing so as part of its next base distribution rate case (Company Brief at 555; Company Reply Brief at 91).

c. Analysis and Findings

The Department agrees that the issue of voltage discounts and voltage-driven rates should be examined inasmuch as changes in the power system related to bidirectional power flow may result from the increase in DER (Exh. AG-RNCP-1, at 21 (Rev.)). Without evaluating the results of an ACOSS that differentiates high-voltage customers from other large customers, it is not possible to direct the development of a new rate design at this time. The Department is not persuaded, however, that a single-issue rate proceeding is warranted. Rather, the Department finds that it is appropriate for National Grid to explore the reasonableness and cost impacts of differentiating rates between customers taking service above 13 kV with those taking service at lower voltages, including a new high-voltage rate class, and for the Company to address these issues in its initial filing in its next base distribution rate case. The Department encourages the Company to work with TEC and PowerOptions to the extent possible in exploring these issues.

4. Time-of-Use Periods

a. Introduction

TEC and PowerOptions recommend that the Company's time-of-use periods should be revised to reflect current load patterns and support decarbonization (Exh. TEC/PO-JDB/AN-1, at 23). The Company's Rate G-3 customers have two pricing periods, with peak hours defined as 8:00 a.m. to 9:00 p.m. daily on Monday through Friday, excluding holidays, and off-peak hours defined as all remaining hours (proposed M.D.P.U. No. 1515 (MECo); proposed M.D.P.U. No. 670 (Nantucket Electric)). TEC and PowerOptions explain that with peak demand shifting to later in the afternoon and mid-day loads decreasing, there is an increased need for flexible loads that can ramp up consumption during mid-day hours (Exh. TEC/PO-JDB/AN-1, at 23). TEC and PowerOptions further state that the current rate design penalizes these resources through higher demand charges and acts as a barrier to flexible loads that would otherwise benefit the distribution system during periods of excess renewable generation (Exh. TEC/PO-JDB/AN-1, at 23).

TEC and PowerOptions recommend that the Company's peak period hours be shortened in duration to better align with actual customer loads, cost causation, and the Commonwealth's decarbonization policies (Exh. TEC/PO-JDB/AN-1, at 30). TEC and PowerOptions also recommend that new time-of-use rates reflect seasonal differences to better account for expected increases in severe light load conditions during shoulder months (Exh. TEC/PO-JDB/AN-1, at 30). TEC and PowerOptions recommend defining the summer peak period as 1:00 p.m. to 9:00 p.m. and the non-summer peak period as 5:00 p.m. to 9:00 p.m. to better communicate price signals to consumers and encourage the use of flexible loads (Exh. TEC/PO-JDB/AN-1, at 30). In particular, TEC and PowerOptions state that the Company has proposed an optional EV time-of-use rate in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-85, with a peak period of 1:00 p.m. to 9:00 p.m. Monday through Friday, excluding holidays, which is aligned with the Company's Off-Peak Charging Rebate program established in D.P.U. 18-150 (Exh. TEC/PO-JDB/AN-1, at 29, citing D.P.U. 23-85, prefiled testimony of Achyut Shrestha and Scott McCabe at 11).

b. Positions of the Parties

i. Attorney General

The Attorney General agrees with TEC and PowerOptions that the Company's peak period hours are overly expansive and should be revised (Attorney General Reply Brief at 43-44). The Attorney General maintains that peak period for time-of-use rates should be tailored to provide financial incentives to shift energy consumption away from the hours of the day with the greatest demand (Attorney General Reply Brief at 43). The Attorney General asserts that while she recommends approval of TEC and PowerOptions' proposal as an improvement to the current peak period definition, she maintains her recommendation that the

Department conduct a comprehensive evaluation of all customer rates and load management programs (Attorney General Reply Brief at 45).

ii. TEC and PowerOptions

TEC and PowerOptions contend that revised peak period hours are needed to incentivize the use of flexible loads (TEC and PowerOptions Brief at 9). TEC and PowerOptions maintain that the Company's analysis demonstrating the adequacy of current peak hours was overly expansive by using a threshold of 70 percent of the Company's all-time peak demand to determine the appropriate peak period (TEC and PowerOptions Brief at 10). TEC and PowerOptions assert that summer peak demand data shows significant changes to demand since 2014 and a strong trend toward maximum demand occurring later in the day, which they contend indicates a need to revise peak period hours to align with actual customer loads (TEC and PowerOptions Brief at 10).

iii. Company

The Company maintains that its current peak period is appropriate and reflective of the diverse needs of the distribution system (Company Reply Brief at 92). The Company asserts that in the period April 2014 to March 2023, there were 90 summer peak days when the system load exceeded 70 percent of the all-time peak of 3.3 GWh, as well as 86 summer peak days when the system load exceeded 3.3 GWh, as late as hour 22 (i.e., 9:00 p.m. to 10:00 p.m.) (Company Reply Brief at 91-92). Based on this data, the Company maintains that the time-of-use period should not be adjusted (Company Reply Brief at 92).

c. Analysis and Findings

The Department has given careful consideration to TEC and PowerOptions' recommended modification to the Company's time-of-use rate. As an initial matter, we are not persuaded by the comparison to the Company's proposed peak period modifications in D.P.U. 23-85 with respect to EV time-of-use customers. Rather, the Department must examine whether changing the peak periods for Rate G-3 aligns better with those customers' loads and climate policy objectives. In this regard, even if we were inclined to accept TEC and PowerOptions' proposed peak period modifications, the record is insufficient to enable the Department to develop an appropriate peak period rate for Rate G-3 customers at this time. The Department requires additional data and analysis to determine the appropriate hours to most effectively target peak hour charges for this specific rate class to encourage load reduction, as well as determine the appropriate portion of the revenue requirement to allocate to such charge. The Department has indicated that we intend to investigate rate design changes that better reflect the Commonwealth's clean energy goals, specifically electrification and decarbonization, in the coming years. See e.g., D.P.U. 22-22, at 61, 123; D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, at 313-315. We recognize that various rate class time-of-use periods, including periods related to times of system peaks, is an issue to be explored. Further, we conclude that to facilitate a more thorough review, we should address revised peak periods once the Company has moved forward on AMI implementation. At that time, we expect to have more robust usage information to review and to be in a better position to consider 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, the Department declines to direct the Company to modify to its current peak period definitions at this time.

E. 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. 23-80/D.P.U. 23-81, at 419; D.P.U. 22-22, at 475; D.P.U. 17-05-B at 260. As noted above, the Department's long-standing policy regarding the allocation of class revenue requirements is that a company's total distribution costs should be allocated on the basis of equalized rates of return. D.P.U. 23-80/D.P.U. 23-81, at 419-420; D.P.U. 22-22, at 473; D.P.U. 17-05-B at 260-261; D.T.E. 02-24/02-25, at 256. This allocation method satisfies the Department's rate design goal of fairness. D.P.U. 23-80/D.P.U. 23-81, at 420; D.P.U. 22-22, at 473; D.P.U. 17-05-B at 261. Nonetheless, the Department must balance its goal of fairness with its goal of continuity. D.P.U. 23-80/D.P.U. 23-81, at 420; D.P.U. 22-22, at 473-474; D.P.U. 17-05-B at 261. For this balancing, we have reviewed the changes in total revenue requirement by rate class and bill impacts by consumption level within rate classes. The rate design for each rate class is discussed in detail below.

The basic components of an electric company's distribution rates are: (1) the customer charge, which is a fixed amount per month; and (2) the base distribution energy charge, which is based on electricity usage in kWh over the billing cycle. D.P.U. 23-80/D.P.U. 23-81, at 420. An additional component for C&I customers is a base distribution demand charge, which is based on a customer's peak load in kW. D.P.U. 23-80/D.P.U. 23-81, at 420. The customer charge is intended to recover the fixed costs to serve a customer that do not vary with a customer's electricity use, such as the costs of billing and metering. D.P.U. 23-80/D.P.U. 23-81, at 420. Distribution energy charges are a function of a customer's use and, therefore, impact a customer's bill in proportion to how much electricity the customer consumed in a given billing cycle. D.P.U. 23-80/D.P.U. 23-81, at 420. A distribution demand charge is intended to recover capacity-related costs and is a function of a general service customer's highest monthly usage at a single point in time in the billing cycle. D.P.U. 23-80/D.P.U. 23-81, at 420.

2. Rate R-1 and Rate R-2: Residential Delivery Service

a. Company Proposal

Rate R-1 is available to all residential customers and for church and farm purposes (Exhs. NG-PP-1, at 27; proposed M.D.P.U. No. 1511 (MECo); proposed M.D.P.U. No. 666 (Nantucket Electric)). Rate R-2 is available to low-income residential customers who meet the specified criteria in the Company's tariff (Exhs. NG-PP-1, at 27; proposed M.D.P.U. No. 1512 (MECo), proposed M.D.P.U. No. 667 (Nantucket Electric)). The current distribution structure and rates for both Rate R-1 and Rate R-2 include a fixed monthly customer charge and a dollar per kWh distribution energy charge.

The Company proposes to increase: (1) the monthly customer charge from $7.00 to $11.00; and (2) the distribution energy charge from $0.06043 per kWh to $0.06588 per kWh for both Rate R-1 and Rate R-2 customers (Exhs. NG-PP-1, at 27-28; NG-PP-6, at 2 (Rev. 4); NG-PP-11, at 2 (Rev. 4); NG-PP-12, at 2 (Rev. 4)). Currently, Rate R-2 customers receive a 32 percent discount on the total bill, with the discounted amount recovered from all retail delivery service customers through the Residential Assistance Adjustment Factor ("RAAF")

(Exh. NG-PP-1, at 27). The Company proposes to change the low-income discount from the current flat discount rate of 32 percent to a multi-tiered structure based on household income level (Exhs. NG-PP-1, at 26-27; NG-CP-1, at 28). The Company's proposed changes to the low-income discount are discussed in Section XVI. Additionally, as discussed above, the Company proposed an Electrification Pricing option for Rate R-1 customers, which the Department rejected.

b. Positions of the Parties

i. Attorney General

The Attorney General opposes the Company's proposed increase in its residential fixed monthly customer charge from $7.00 to $11.00 and advocates instead for a lower charge of $7.77 (Attorney General Brief at 130). The Attorney General claims this lower charge would more accurately reflect the appropriate classification of costs between fixed and volumetric charges, ensure alignment with cost-causation principles, prevent undue burdens on low-income customers, and encourage energy conservation (Attorney General Brief at 134).

The Attorney General argues that the Company's proposal, which the Company asserts moves the charge closer to the customer-related costs to serve Rates R-1 and R-2, fails to accurately reflect cost causation by improperly including certain costs as customer-related costs (Attorney General Brief at 130-131). Additionally, the Attorney General contends that the proposed fixed charge: (1) undermines efforts to promote conservation and energy efficiency, which she contends are more effectively incentivized through a higher volumetric rate rather than a higher fixed charge; and (2) disproportionately affects low-usage customers, who are often low-income (Attorney General Brief at 131).

The Attorney General also raises two primary issues with the Company's proposed customer-related costs to serve Rates R-1 and R-2: (1) service line costs; and (2) A&G expenses. First, the Company classifies service lines as entirely customer-related costs, whereas the Attorney General argues that service line costs vary not only by the number of customers but also by demand factors such as geography and topography (Attorney General Brief at 132). Consequently, the Attorney General recommends that only a portion of these costs should be included in the fixed customer charge, with the remainder classified as demand-related and recovered through volumetric rates (Attorney General Brief at 132-133). Based on the available data, the Attorney General proposes that only $1.07 of the $2.14 service line costs be included in the fixed charges (Attorney General Brief at 133, citing Exh. AG-11-6).

Second, concerning the Company's classification of A&G expenses as 100 percent customer-related costs and their inclusion in the fixed customer charge, the Attorney General argues that while these expenses do support customer-related functions such as metering, billing, and maintaining assets, they are more appropriately aligned with demand-related costs (Attorney General Brief at 133). Further, the Attorney General argues that A&G expenses, which include salaries, office supplies, and employee benefits, do not benefit all customers equally and should therefore be recovered through volumetric rates rather than through fixed charges (Attorney General Brief at 133-134). The Attorney General asserts that $3.14 in A&G costs should be removed from the fixed charges (Attorney General Brief at 134).

In addition, the Attorney General recommends that the Department direct the Company to collect the necessary data to establish a cost-based multi-family rate and to propose such a rate in its next base distribution rate case (Attorney General Brief at 187). Multi-family rates are designed for customers in multi-unit dwellings, such as apartment buildings, and, although the Company does not currently offer such a rate, similar rates are implemented by utilities across the country (Attorney General Brief at 187, citing Exh. AG-RNCP-1, at 62).

The Attorney General contends that there is substantial evidence suggesting that serving multi-family buildings is generally less costly than serving single-family homes (Attorney General Brief at 188, citing Exh. AG-RNCP-1, at 63). The Attorney General explains the reasons for this lower cost include shared service drops and master meters, which reduce distribution costs per customer, as well as typically lower demand from multi-family customers, leading to reduced intra-class allocation of demand-related costs (Attorney General Brief at 188-189, citing Exh. AG-RNCP-1, at 63). The Attorney General asserts that collecting the necessary data and implementing a cost-based multi-family rate would benefit multi-family customers and promote fairness in rate design (Attorney General Brief at 189).

ii. DOER

DOER supports the Company's proposed increase in Rates R-1 and R-2 customer charges from $7.00 to $11.00 per month (DOER Brief at 48). DOER argues that the proposed increases will contribute to a just, reasonable, and more cost-reflective electric rate design (DOER Brief at 48). Additionally, DOER contends that the proposed increase strikes a balance between cost-reflective pricing and maintaining incentives for electrification and energy efficiency (DOER Brief at 48). Further, DOER asserts that approval of these increases aligns with broader energy policy goals including promoting fair and equitable rate structures and encourages sustainable energy use (DOER Brief at 48).

iii. MEDA

MEDA opposes the Company's proposed increase to its monthly residential customer charge from $7.00 to $11.00 and agrees with Attorney General's arguments in opposition to this increase (MEDA Reply Brief at 28). In particular, MEDA reiterates the concern that increases in customer charges disproportionately fall on low-income customers (MEDA Reply Brief at 28, citing Attorney General Brief at 136-138). Therefore, MEDA maintains that the Department should be concerned that such an increase undermines the goal of ensuring equitable and affordable rates for low-income households, which is part of the Department's mandate (MEDA Reply Brief at 28, citing G.L. c. 25, §1A).

iv. Company

The Company asserts that its proposed increase in the monthly residential customer charge from $7.00 to $11.00 should be accepted by the Department for the following reasons: (1) cost-based justification; (2) inappropriate exclusion of costs by the Attorney General; (3) minimal impact on volumetric rates; and (4) support from DOER (Company Brief at 553).

First, the Company argues that its proposed $11.00 monthly charge reflects the actual customer-related costs incurred by the Company to connect, meter, and bill a residential customer (Company Brief at 554). National Grid maintains that it has calculated these costs to be $11.98 per customer per month, which includes necessary expenses such as service line costs, A&G expenses, and employee-related costs (Company Brief at 553-554, citing Exh. NG-PP-2C, Line 21; Company Reply Brief at 88-89). The Company contends that the proposed $11.00 customer charge moves rates closer to these actual costs (Company Brief at 553-554, citing Exh. NG-PP-2C, Line 21; Company Reply Brief at 89, citing Exh. NG-PP-Rebuttal-1, at 16).

Second, the Company argues that the Attorney General's recommended customer charge of $7.77 per month is based on an arbitrary and incorrect exclusion of $1.07 per customer per month related to service lines and $3.14 per customer per month for A&G costs (Company Brief at 553). The Company maintains that residential service lines have an average cost of $388 and the cost for 92.9 percent of residential customers is $371 or greater (Company Brief at 553, citing Exh. NG-PP-3J). Thus, the Company asserts that exclusion of more than $0.10 ($371/$388 x $2.41) is incorrect (Company Brief at 553). Additionally, the Company contends that A&G costs, including those related to employee pension, A&G salaries, and billing software, are integral to customer service and should be included in the fixed charge (Company Brief at 553-554). In summing the values of the unit costs associated with these A&G costs, the Company claims that only $0.32 of the Attorney General's proposed exclusion amount of $3.14 from the customer charge could not be tied to specific A&G cost categories that are required to connect and bill customers (Company Brief at 553).

Third, the Company refutes the Attorney General's and MEDA's claim that a higher customer charge is anti-conservation and exacerbates rate increase effects on low-income customers (Company Brief at 554). The Company argues that adopting the Attorney General's proposed customer charge of $7.77 per month would result in only a minor increase in volumetric rates by $0.00503 per kWh, a negligible portion of the total rate of $0.16202 per kWh (Company Brief at 554). Moreover, the Company maintains that the customer charge should not be considered in a vacuum (Company Reply Brief at 89, citing Exh. NG-PP-Rebuttal-1, at 16).

Finally, the Company asserts that DOER supports the proposed customer charge increases as a more cost-reflective electric rate design that balances the incentives for electrification and efficiency (Company Brief at 554).

Regarding the multi-family rate issue, the Company contends that the Attorney General's recommendation to conduct a study on the costs to serve multi-family versus single-family customers and to propose a multi-family rate should be rejected (Company Brief at 555). National Grid argues that there is insufficient data to support a comprehensive study on the cost differences between serving multi-family and single-family customers, and the Company lacks the detailed cost information necessary for such a study (Company Brief at 554). Additionally, the Company asserts that the expense of conducting this study has not been quantified so the potential cost implications are unsubstantiated (Exh. NG-PP-Rebuttal-1, at 16).

National Grid also challenges the Attorney General's assertion that separate muti-family rates would yield significant benefits, and the Company argues that the benefits cited by the Attorney General are speculative and based on limited, anecdotal evidence from a few utilities (Company Brief at 555). The Company maintains that the evidence provided by the Attorney General does not robustly support the anticipated advantages of introducing muti-family rates (Company Brief at 555). Finally, the Company asserts that implementing the Attorney General's recommendation would involve significant effort, cost, and complexity, with only modest benefits, and could lead to a minor cost shift from multi-family residential customers to other customer classes (Company Brief at 555).

c. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for Rates R-1 and R-2 is $12.01 per month (Exh. NG-PP-2C (Rev. 4)). With respect to the customer charge, the Company has requested an increase of 56 percent of the current charge, from $7.00 to $11.00. While DOER supports an $11.00 customer charge, the Attorney General instead recommends a $7.77 customer charge (DOER Brief at 48; Attorney General Brief at 130). The Company, on the other hand, contends that exclusion of more than $0.10 of the $2.14 for service drops is incorrect, and that only $0.32 of the Attorney General's proposed exclusion amount of $3.14 from the customer charge for A&G costs could not be tied to specific A&G cost categories that are required to connect and bill customers (Company Brief at 553).

The Department has reviewed the record and finds insufficient evidence to support the Attorney General's exclusion of $1.07 per customer per month related to service lines and $3.14 per customer per month for A&G costs in determining the proper customer charge (Exhs. NG-PP-Rebuttal-1, at 14-16; NG-PP-3J (Rev. 4); NG-PP-2G-1 (Rev. 4); AG-RNCP-1, at 27; DPU-AG 2-4, Att.; Tr. 9, at 1255-1257). However, the Department finds that while a customer charge of $11.00 per month for Rates R-1 and R-2 better represents the fixed costs to serve residential customers per the ACOSS, the increase violates the rate design principle of continuity. Therefore, the Department rejects a customer charge of $11.00 per month for Rates R-1 and R-2 and instead directs the Company to set the customer charge at $10.00. The Department finds that a customer charge of $10.00 per month appropriately balances rate continuity with cost-reflective pricing and maintaining incentives for electrification and energy efficiency in this instance. The Company shall set the volumetric energy charge for Rates R-1 and R-2 to recover the remaining class distribution revenue requirement approved in this Order. With respect to G.L. c. 164, § 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful deployment of energy efficiency and on-site generation.

Regarding the Attorney General's recommendation that the Department direct the Company to establish a cost-based multi-family housing rate, and to propose such a rate in its next base distribution rate case, we deny this request. In determining whether a new rate class is warranted, we must balance cost causation with our goal of simplicity. Although the cost to serve a customer residing in a multi-family dwelling may be lower than the cost to serve a Rate R-1 customer residing in a single-family house, it does not necessarily follow that a separate rate should be developed. The cost difference, number of customers impacted, and the benefits must be significant enough to warrant upsetting the simplicity of the current rate structure, and we conclude that there is insufficient record evidence to support this conclusion. For simplicity, the Department endeavors to minimize the number of rate classes and, therefore, cost-to-serve differences and customers impacted must be significant to warrant a rate structure change to meet cost causation. In this instance, we are not convinced that the difference in the cost to serve and the potential benefits are significant enough to approve the Attorney General's recommendation.

3. Rate G-1: General Small Commercial and Industrial Delivery Service

a. Company Proposal

Rate G-1 is available to C&I customers that have average use not exceeding 10,000 kWh or 200 kW of demand (Exhs. NG-PP-1, at 30; proposed M.D.P.U. No. 1513 (MECo); proposed

M.D.P.U. No. 668[235] (Nantucket Electric)). Rate G-1 currently includes a monthly customer charge, a kWh distribution energy charge, and a minimum charge (Exh. NG-PP-1, at 30). Unmetered customers pay a location charge instead of the customer charge, which is intended to exclude meter-related costs from the customer charge (Exh. NG-PP-1, at 30). The current and proposed charges for Rate G-1 are as follows:

		Current	**Proposed**
Metered Service	**Customer Charge**	$10.00/month	$14.00/month
	Volumetric Charge	$0.05285/kWh	$0.05390/kWh
	Minimum Bill Charge	$3.23/month	Eliminated
Unmetered Service	**Location Charge**	$7.50/month	$10.00/month

(Exhs. NG-PP-6, at 4 (Rev. 4); NG-PP-11, at 9 (Rev. 4); NG-PP-12, at 9 (Rev. 4)).

The Company proposes to eliminate the minimum bill charge, established in the 1980s, because transformer capacity decisions now consider system-wide planning objectives rather than the needs of individual customers (Exh. NG-PP-1, at 31). The Company explains that with over 70 percent of Rate G-1 customers served by transformers of 50 kVA or above, the charge no longer reflects direct cost causation (Exh. NG-PP-1, at 31). Further, the Company notes that the incremental costs for larger transformers will be recovered through a CIAC payment for new customers instead (Exh. NG-PP-1, at 31-32).

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235 It appears that the Company, in its initial filing, incorrectly numbered the proposed tariff as M.D.P.U. No. 688. To the extent National Grid intended to number the tariff M.D.P.U. No. 688, the tariff still is disallowed, consistent with the Ordering Clauses below.

b. Positions of the Parties

DOER supports the Company's proposed increase in the small commercial (Rate G-1) customer charges from $10.00 to $14.00 per month (DOER Brief at 48). DOER asserts that the proposed increases will contribute to a just, reasonable, and more cost reflective electric rate design (DOER Brief at 48). Additionally, DOER maintains that the increase strikes a balance between cost-reflective pricing and maintaining incentives for electrification and energy efficiency (DOER Brief at 48). Further, DOER contends that the approval of this customer charge increase aligns with broader energy policy goals including promoting fair and equitable rate structures while encouraging sustainable energy use (DOER Brief at 48). The Company reiterates its proposal on brief (Company Brief at 540-541).

c. Analysis and Findings

According to the Company's ACOSS, the embedded customer charge for Rate G-1 is $15.42 per month (Exh. NG-PP-2C (Rev. 4)). The Company proposes a customer charge of $14.00. Based on the embedded customer charge, customer bill impacts, and the Commonwealth's policy goals for electrification and energy efficiency, the Department finds that a customer charge of $12.00 per month for Rate G-1 best meets our rate design goals and objectives while still maintaining cost-reflective pricing and incentives for electrification and energy efficiency. Therefore, the Department approves a customer charge of $12.00 per month for Rate G-1. For unmetered customers on Rate G-1, the Department finds a location charge of $10.00 per month best meets our rate design goals and objectives. Thus, the Department accepts the Company's location charge proposal. With respect to G.L. c. 164, § 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful deployment of energy efficiency and on-site generation. Therefore, the Company shall set the volumetric energy charge for Rate G-1 to recover the remaining class distribution revenue requirement approved in this Order. Finally, the Department approves the Company's proposal to eliminate the minimum charge because it no longer reflects cost causation.

4. Rate G-2: General Demand Delivery Service

a. Company Proposal

Rate G-2 is a general service rate for C&I customers that have average consumption greater than 10,000 kWh and do not exceed 200 kW of demand (proposed M.D.P.U. No. 1514 (MECo); proposed M.D.P.U. No. 669 (Nantucket Electric)). The current rates include a monthly customer charge, a distribution demand charge, a distribution energy charge, discounts for high voltage metering if a customer takes service at higher voltage levels, and discounts for high voltage delivery if the customer accepts delivery service at the Company's supply line voltage, not less than 2,400 volts, and the Company avoids the cost of installing any transformer and associated equipment (Exh. NG-PP-1, at 32). An additional charge applies for customers requiring a second feeder (Exh. NG-PP-1, at 32). The current and proposed charges for Rate G-2 are as follows:

	Current		Proposed	
Customer Charge	$30.00/month		$54.00/month	
Demand Charge	$13.36/kW-month		$15.03/kW-month	
Distribution Energy Charge	$0.00260/kWh		**	
Second Feeder Charge	$8.77/kW-month (no transformer)	$9.47/kW-month (with transformer)	$9.69/kW-month (no transformer)	$10.43/kW-month (with transformer)
High Voltage Delivery Discount*	$0.70/kW-month		$0.74/kW-month	
High Voltage Metering Discount	0.0514% of distribution revenue		0.0481% of distribution revenue	

* High Voltage Delivery Discount of Demand for service at voltages not less than 2,400 volts.
** The Company proposes to eliminate the kWh-distribution energy charge.

(Exhs. NG-PP-6, at 5 (Rev. 4); NG-PP-7 (Rev. 4); NG-PP-11, at 10-15 (Rev. 4); NG-PP-12, at 10-15 (Rev. 4)).

The proposed Rate G-2 EV pricing rates, which the Company states are calculated consistent with the method approved in Electric Vehicle Infrastructure Program, D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92 (2022) are as follows:

	Load Factor	Demand-based Rate	Distribution kWh Energy Charge
Price Schedule A	Less than 5%	0% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue
Price Schedule B	Greater than 5% and less than 10%	25% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue
Price Schedule C	Greater than 10% and less than 15%	50% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue
Price Schedule D	Greater than 15%	100% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue

(Exh. NG-PP-1, at 34).

b. Analysis and Findings

According to the Company's ACOSS, the customer-related cost to serve the G-2 rate class is $58.78 per month, and National Grid proposes a monthly customer charge of $54.00 (Exh. NG-PP-2C (Rev. 4)). Based on a review of the bill impacts on customers, the Department finds that the monthly customer charge, proposed to increase from $30.00 to $54.00 (an 80 percent increase) does not satisfy continuity goals (Exhs. NG-PP-11, at 9 (Rev. 4); NG-PP-12, at 9 (Rev. 4)). These continuity goals are better served by a monthly customer charge of $45.00, which we adopt.

The Department finds the Company's proposal to eliminate the distribution energy charge is reasonable because the costs to serve do not vary with energy consumption, the charge was not based on when electricity use occurred, and the revenue from the distribution energy charge was small, i.e., less than six percent of the Rate G-2 class revenue. The Department finds that the Company's proposed method for calculating the second feeder charges with and without a transformer, as well as the proposed method for calculating the high voltage delivery discount and the proposed method for calculating the high voltage metering discount, satisfies our rate design goals and are reasonable (Exhs. NG-PP-6, at 5 (Rev. 4); NG-PP-7). Therefore, the Department directs the Company in its compliance filing to recalculate the second feeder charges with and without a transformer, the high voltage delivery discount, and the high voltage metering discount using its proposed method, the approved ACOSS, and the approved Rate G-2 demand charge. Further, with respect to G.L. c. 164, § 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful deployment of energy efficiency and on-site generation. Therefore, the Company shall set the distribution demand charge to collect the balance of the class revenue requirement approved in this Order.

Regarding the proposed Rate G-2 EV pricing rates, the Department finds they are calculated consistent with the method approved in D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 265-266, and result in just and reasonable rates. We direct the Company to calculate the Rate G-2 EV rates using the method approved in D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, which is proposed by the Company, based on the final distribution demand charge calculated per this Order.

5. Rate G-3: General Time-of-Use Delivery Service

a. Company Proposal

Rate G-3 is a general service time-of-use rate class for C&I customers with billing demand exceeding 200 kW (Exh. NG-PP-1, at 35; proposed M.D.P.U. No. 1515 (MECo); proposed M.D.P.U. No. 670 (Nantucket Electric)). The current rate structure includes a customer charge, a distribution demand charge, a peak period[236] distribution energy charge, with additional charges for customers requiring a second feeder, and discounts for high voltage metering and high voltage delivery if the customer accepts delivery service at the Company's supply line voltage, greater than 2,400 volts (Exh. NG-PP-1, at 35). The current and proposed charges for Rate G-3 are as follows:

[236] Peak period is defined as 8:00 a.m. to 9:00 p.m., Monday through Friday, excluding holidays (Exh. NG-PP-1, at 35).

	Current		Proposed	
Customer Charge	$223.00/month		$350.00/month	
Demand Charge	$9.63/kW-month		$10.58/kW-month	
Distribution Energy Charge	$0.00210/peak period kWh		0.00267/peak period kWh	
Second Feeder Charge	$8.77/kW-month (no transformer)	$9.47/kW-month (with transformer)	$9.69/ kW-month (no transformer)	$10.43/kW-month (with transformer)
High Voltage Delivery Discount	$0.70/kW (2,400 to < 115 kV)	$9.47/kW (>=115 kV)	$0.74/kW (2,400 to < 115 kV)	$10.43/kW (>=115 kV)
High Voltage Metering Discount	2.9043% of distribution revenue		2.717% of distribution revenue	

(Exhs. NG-PP-6, at 9 (Rev. 4); NG-PP-11, at 16-21 (Rev. 4); NG-PP-12, at 16-21 (Rev. 4)).

The proposed Rate G-3 EV pricing rates, which the Company states are calculated consistent with the method approved in D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, are as follows:

	Load Factor	Demand-based Rate	Distribution kWh Energy Charge
Price Schedule A	Less than 5%	0% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue
Price Schedule B	Greater than 5% and less than 10%	25% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue
Price Schedule C	Greater than 10% and less than 15%	50% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue
Price Schedule D	Greater than 15%	100% of standard Rate G-2 demand rate	Computed to collect shortfall in Demand-based revenue

(Exh. NG-PP-1, at 34).

b. Analysis and Findings

According to the Company's ACOSS, the customer-related cost to serve the G-3 rate class is $376.10 per month (Exh. NG-PP-2C (Rev. 4)). Based on a review of the bill impacts on customers, the Department finds that the monthly customer charge, proposed to increase from $223.00 to $350.00, satisfies our rate design goals and produces bill impacts that are moderate and reasonable (Exhs. NG-PP-11, at 16-21 (Rev. 4); NG-PP-12, at 16-21 (Rev. 4)). The Department finds that a peak energy distribution charge of $0.00259 per kWh satisfies our rate design goals and produces bill impacts that are moderate and reasonable. The Department finds that the Company's proposed method for calculating the second feeder charges with and without a transformer, as well as the proposed method for calculating the high voltage delivery discounts and the proposed method for calculating the high voltage metering discount, satisfies our rate design goals and are reasonable (Exhs. NG-PP-6, at 9 (Rev. 4); NG-PP-7). Therefore, the Department directs the Company in its compliance filing to recalculate the second feeder charges with and without a transformer, the high voltage delivery discounts, and the high voltage metering discount using its proposed method, the approved ACOSS, and the approved Rate G-3 demand charge. Further, with respect to G.L. c. 164, § 141, the Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful deployment of energy efficiency and on-site generation. Therefore, the Company shall set the distribution demand charge to collect the balance of the class revenue requirement approved in this Order. Regarding the proposed Rate G-3 EV pricing rates, the Department finds that they are calculated consistent with the method approved in D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 265-266, and result in just and reasonable rates. We direct the Company to calculate the Rate G-3 EV rates using the method approved in D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, which is proposed by the Company, based on the final distribution demand charge calculated per this Order.

6. Street Lighting

a. Introduction and Company Proposal

National Grid's street lighting rate classes encompass a variety of options tailored to different ownership and maintenance responsibilities (Exh. NG-PP-1, at 37). The Company currently has six street lighting rate classes: (1) Rate S-1, for Company-owned and maintained luminaires and supports; (2) Rate S-2, for customer-owned luminaires mounted on Company-owned distribution poles, with maintenance provided by the Company (closed to new customers); (3) Rate S-3, Option A, for underground lighting installations with customer-owned foundations and Company-owned and maintained luminaires and supports; (4) Rate S-3, Option B, for underground lighting installations with customer-owned luminaires and supports partially maintained by the Company (closed to new customers); (5) Rate S-5, for customer-owned and maintained luminaires and supports; and (6) Rate S-6, for Company-owned and maintained decorative street and area lighting (Exh. NG-PP-1, at 37). The Company proposes to increase each of the rates in the street lighting rate classes by approximately 22.59 percent (Exhs. NG-PP-1, at 38; NG-PP-6, at 13 (Rev. 4)).

b. Analysis and Findings

The Department finds that the proposed rate design for the street lighting rate classes satisfies our simplicity goal, as well as our continuity goal, and produces bill impacts that are moderate and reasonable, considering the size of the increase (Exhs. NG-PP-11, at 22-26 (Rev. 4); NG-PP-12, at 22-26 (Rev. 4)). Further, with respect to G.L. c. 164, § 141, the

Department has reviewed the resulting rate design and finds that its impact does not inhibit the successful development of energy efficiency and on-site generation. Therefore, the Department directs National Grid to compute the street light charges using the method proposed by the Company, subject to the revenue requirement for the street light class approved in this Order.

F. Revenue Decoupling Proposal

1. Introduction

On January 31, 2022, the Department issued a final Order approving the three-year energy efficiency plans for calendar years 2022 through 2024 ("2022-2024 Three-Year Plans") filed by the Company and others (collectively, "Program Administrators"),[237] subject to certain directives, disallowances, and program modifications. D.P.U. 21-120 through D.P.U. 21-129. The Department also made a general policy pronouncement regarding the future of full revenue decoupling for EDCs. D.P.U. 21-120 through D.P.U. 21-129, at 227-235. Specifically, the Department found that the Program Administrators' strategy of strategic electrification, as set forth in the 2022-2024 Three-Year Plans, potentially obviates the continued use of full revenue decoupling by the EDCs. D.P.U. 21-120 through D.P.U. 21-129, at 227.[238] The Department

[237] In addition to National Grid, the Program Administrators comprise The Berkshire Gas Company; Eversource Gas Company of Massachusetts; Liberty Utilities (New England Natural Gas Company) Corp.; Boston Gas; NSTAR Gas Company; the Towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Eastham, Edgartown, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, Wellfleet, West Tisbury, and Yarmouth, and Dukes County, acting together as the Cape Light Compact JPE; Unitil's electric and gas operating companies; and NSTAR Electric.

[238] The Department explained that it has allowed full revenue decoupling for each EDC and LDC since the passage of the Green Communities Act in 2008, having implemented revenue decoupling in base distribution rate proceedings. D.P.U. 21-120 through

determined that recent changes in the Commonwealth's energy policies call into question the underlying premise supporting the Department's earlier implementation of full revenue decoupling for EDCs. D.P.U. 21-120 through D.P.U. 21-129, at 229, citing An Act to Advance Clean Energy, St. 2018, c. 227; 2021 Climate Act. The policy shift allows Program Administrators to increase electricity consumption through the energy efficiency programs and requires the Program Administrators to drive acceptance of strategic electrification measures to achieve a minimum level of sustained GHG emissions reductions. D.P.U. 21-120 through D.P.U. 21-129, at 229. Therefore, the Department determined that it would discontinue full revenue decoupling for EDCs, thereby ensuring that their business models would continue to align with the Commonwealth's energy and environmental policy goals. D.P.U. 21-120 through D.P.U. 21-129, at 231-232. In doing so, the Department sought to reorient the EDCs to no longer be neutral but, rather, to embrace increasing clean electric load. D.P.U. 21-120 through D.P.U. 21-129, at 232.

In announcing this policy change, the Department directed each EDC, in its next base distribution rate proceeding, to include for adjudication a rate proposal that provides for the

D.P.U. 21-129, at 227, citing D.P.U. 17-05-B at 219; D.P.U. 11-01/D.P.U. 11-02, at 113; D.P.U. 07-50-A at 31-32; D.P.U. 09-39, at 61-92. Full revenue decoupling separates a distribution company's revenues from all changes in consumption, regardless of the underlying cause of the changes, to remove the disincentives distribution companies historically faced regarding deployment of demand-reducing resources. D.P.U. 21-120 through D.P.U. 21-129, at 228, citing D.P.U. 07-50-A at 31. The Department was concerned that, without full revenue decoupling, distribution companies would not be able to fully embrace the successful implementation of demand-reducing measures and actions that became an essential component of the Commonwealth's strategy to mitigate the impact of increasing energy costs with the passage of the Green Communities Act in 2008. D.P.U. 21-120 through D.P.U. 21-129, at 228, citing D.P.U. 07-50-A at 33.

discontinuance of full revenue decoupling. D.P.U. 21-120 through D.P.U. 21-129, at 234.[239] The Department recognized that removal of a full revenue decoupling mechanism comes before any increase in distribution sales from the strategic electrification efforts under the 2022-2024 Three-Year Plans, so the Department would take economic forecasts into account while also examining planned strategic electrification activities. D.P.U. 21-120 through D.P.U. 21-129, at 233-234, citing Statewide Plan, Exh. 1, App. C.l. - Electric (Rev.), Table IV.B.3.1. The Department also indicated that we may consider implementing a targeted decoupling mechanism[240] that achieves the Commonwealth's electrification goals and GHG emissions reduction targets as part of each company's next base distribution rate proceeding. D.P.U. 21-120 through D.P.U. 21-129, at 234 n.145, citing D.P.U. 07-50-A at 29-30.

The Attorney General filed a motion for reconsideration of the Department's decision to eliminate full revenue decoupling for EDCs and the directive that each EDC propose the elimination of full revenue decoupling in its next base distribution rate proceeding. D.P.U. 21-120-B through D.P.U. 21-129-B at 3-4, citing Attorney General Motion for Reconsideration at 3. The Attorney General argued that the Department should open a generic

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[239] NSTAR Electric filed a base distribution rate case less than two weeks after the Department issued D.P.U. 21-120 through D.P.U. 21-129. D.P.U. 22-22, Petition for Approval (January 14, 2022). The Department ultimately determined that NSTAR Electric must file a proposal to eliminate full revenue decoupling in its next base distribution rate case. D.P.U. 21-120-B through D.P.U. 21-129-B at 21.

[240] In determining whether to approve a targeted revenue decoupling mechanism, the Department would consider service-territory-specific factors, such as economic forecasts, the penetration of such technological initiatives as DG and EV charging infrastructure, and company-driven and third-party-driven strategic electrification and energy efficiency efforts. D.P.U. 21-120-B through D.P.U. 21-129-B at 16 n.13.

investigation to explore the future of revenue decoupling for EDCs with participation by all interested stakeholders. D.P.U. 21-120-B through D.P.U. 21-129-B at 3-4, citing Attorney General Motion for Reconsideration at 3-4. The Department denied the Attorney General's motion for reconsideration. D.P.U. 21-120-B through D.P.U. 21-129-B at 12-21. In reaffirming the directive for each EDC to file a proposal in its next base distribution rate case to eliminate full revenue decoupling, the Department noted that it would exercise its underlying mandate to regulate in the public interest in considering (1) the interests of ratepayers and the EDC and (2) the priorities of the Commonwealth's energy and environmental policies. D.P.U. 21-120-B through D.P.U. 21-129-B at 21-22 n.16.

2. Company Proposal

Notwithstanding the Department's directives, the Company did not propose to eliminate full revenue decoupling and instead proposes to maintain full revenue decoupling during its proposed PBR-O term (Exh. NG-CPIP-1, at 213-214). In support of its proposal, the Company states that the results in electric sales growth from electrification are not anticipated to be significant until a time beyond the proposed PBR-O plan in 2029 (Exh. NG-CPIP-1, at 213-214). As such, the Company states that the appropriate time to make changes to the revenue decoupling mechanism is when (1) capital investment supporting the energy transition has leveled off and (2) there is a level of sales growth available to support ongoing capital investment (Exh. DPU 44-1). According to the Company, the point at which these circumstances will occur is presently indeterminate (Exh. DPU 44-1).

Further, the Company states that to eliminate the full revenue decoupling mechanism, energy sales growth fundamentally needs to increase to a level that provides sufficient revenues to warrant "recoupling" (Exh. DPU 44-1). The Company states that such level of load growth will not occur without the incremental buildout in the system to proactively enable the uptake of EVs and electrified heating that will create load growth as the Commonwealth begins the next phase of the electrification-focused energy transition (Exhs. DPU 44-1; AG 13-19). National Grid also states that it anticipates that during the next five years, AMI investments, and in particular, time-varying rates, will enable further changes in rate structures and allow greater affordability for beneficial electrification (Exhs. NG-CPIP-1, at 214; DOER 2-3). According to National Grid, even limiting the mechanism to partial revenue decoupling would not be appropriate until the Company experiences enough sales growth through the recoupled portion of rates to support ongoing capital investment (Exh. DPU 44-2). Based on these reasons, National Grid requests to defer filing a proposal to eliminate full revenue decoupling until such time as a comprehensive rate design proceeding related to AMI capabilities results in new rate designs, so that the Company can assess how these capabilities would be impacted by any recoupling (Exh. NG-CPIP-1, at 214).

3. Positions of the Parties

a. DOER

DOER argues that the Department should consider rejecting National Grid's request to defer a proposal to discontinue full revenue decoupling and instead direct the Company to prepare a recoupling rate proposal (DOER Brief at 70). DOER contends that continued additional or incremental capital spending under full revenue decoupling may undermine the Commonwealth's efforts to decrease electric rates and increase electrification technology adoption (DOER Brief at 71). Further, DOER claims that discontinuing revenue decoupling could incentivize EDCs to leverage their relationship with customers to increase deployment of efficient high-throughput end-use technologies (e.g., air-source heat pumps, EVs) (DOER Brief at 72). Additionally, DOER maintains that following the discontinuance of full revenue decoupling, National Grid would be able to retain sales from increased load, which may incentivize the Company to further develop innovative solutions to promote strategic electrification (DOER Brief at 72).

DOER acknowledges the Department's recent decision to maintain Unitil's full revenue decoupling mechanisms (DOER Reply Brief at 8, citing D.P.U. 23-80/D.P.U. 23-81, at 417-419). Nevertheless, DOER takes issue with the Company's reasoning for maintaining full revenue decoupling (DOER Reply Brief at 8-9). DOER argues that the Company's forecasted volumetric sales by 2029 will be "anything but flat," as energy from EV charging and electric heat pumps is estimated to be 7.3 percent and 2.3 percent of net energy load, respectively (DOER Reply Brief at 9, citing Exhs. DOER 3-3; DOER 3-11, Att.). Further, DOER contends that the Company expects to invest an annual average of approximately $1.4 billion in the next five years and by 2029 anticipates its annual capital investments will be more than quadruple the level of capital spending as compared to its test year to meet the Commonwealth's clean energy goals, including for the electrification of heating and transportation (DOER Reply Brief at 9, citing Exh. NG-CPIP-1, at 58, Table 2).

DOER also argues that in considering future recoupling proposals, the Department should consider targeted mechanisms, expanding on existing policy-driven priorities, to incentivize load management and DER (DOER Brief at 72). DOER urges the Department to consider that recoupling has the potential to allow alignment of the Company's business practices with the

Commonwealth's primary strategies of building and transportation electrification to meet GHG emission limits and sector sub-limits (DOER Brief at 72-73; DOER Reply Brief at 9). DOER asserts that if the Department finds recoupling appropriate, it should direct all EDCs to submit a complete proposal in their next base distribution rate cases, so that all parties can evaluate a substantive proposal (DOER Reply Brief at 9).

b. Company

National Grid repeats its proposal on brief (Company Brief at 245-246). National Grid argues that DOER overstates the Company's expected increase in sales over the term of the proposed five-year rate plan because DOER fails to recognize that much of the increase in sales from heat pumps and EVs will be offset by the decline in sales due to energy efficiency and photovoltaics (Company Reply Brief at 45, citing Exh. DOER 3-3). Further, the Company contends that DOER conflates the Company's core capital addition needs with spending on ESMP investments for future electrification growth (Company Reply Brief at 45). The Company claims it will need to make a significant amount of capital investments, regardless of potential increased sales volumes (Company Reply Brief at 45).

National Grid also argues that immediate significant changes to rate structures could lead to confusion in the future if rates are changed again because of the AMI rate design proceeding (Company Reply Brief at 45). The Company contends that any confusion could potentially undermine customers' comfort that they can project utility rates and resulting bill impacts, thereby leading to uncertainty and a lack of trust in deciding whether to adopt heat pumps, EVs, or even energy efficiency improvements (Company Reply Brief at 45). As such, the Company asserts that its request to defer submitting a proposal to eliminate full revenue decoupling should be approved (Company Reply Brief at 45).

4. Analysis and Findings

As noted above, in evaluating the most recent 2022-2024 Three-Year Plans, the Department directed the EDCs, including the Company, to submit a proposal in their next base distribution rate cases that provides for the discontinuance of full revenue decoupling. D.P.U. 21-120 through D.P.U. 21-129, at 234. National Grid did not file such a proposal in this proceeding, but rather requested to defer this requirement until results in electric sales growth from electrification are more robust and a comprehensive rate design proceeding related to AMI capabilities results in new rate designs (Exhs. NG-CPIP-1, at 213-214; DPU 44-1; DOER 2-3).

Over the next five years, National Grid expects to make substantial capital investments, including to enable the uptake of EVs and electrified heating, as the Company works toward a timely energy transition and increasing its electric load to achieve the Commonwealth's decarbonization objectives (Exhs. DPU 44-1; AG 13-19). As detailed in D.P.U. 24-10/D.P.U. 24-11/D.P.U. 24-12, the Company anticipates spending over $2.5 billion in ESMP investments alone over the next five years. Heat electrification will be a primary strategy, and this transition will involve significant levels of customer investment in building retrofits and new technologies, such as heat pumps, to replace traditional fossil fuel-fired heating systems (Exh. NG-CP-1, at 53). As discussed in Section XV.C.4. above, the Department directs the Company to submit for approval a heat pump rate for all customers in Rates R-1 and R-2 who install and use heat pumps in all or part of their home. The Company also continues to implement its grid modernization investments previously approved by the Department in Second

Grid Modernization; Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122 (2018). As the Company moves forward with electrification options, addressing affordability barriers will require that various incentives and financing options be available, likely joined by rate design changes (Exh. NG-CP-1, at 53, 56). As discussed above in this Order, the Department approves the Company's PBR-O plan and a capital tracker for core capital investments. The Department expects that under these ratemaking designs, the Company will continue to make important investments toward electrification and decarbonization in an efficient way that maintains a safe and reliable distribution system.

As we recognized recently in Unitil's base distribution rate case, while the Company is making meaningful progress in meeting the Commonwealth's clean energy objectives, the timing and extent of widespread acceptance of electrification and decarbonization remains uncertain and can be affected by service-area specific factors (Exhs. NG-CP-1, at 53, 56; DPU 44-1; AG 13-19). D.P.U. 23-80/D.P.U. 23-81, at 417; D.P.U. 21-120-B through D.P.U. 21-129-B at 16 n.13; D.P.U. 21-120 through D.P.U. 21-129, at 233-234. In this regard, we acknowledge the Company's concerns and challenges in reaching sufficient infrastructure buildout to enable increased EVs and electrified heating that will create load growth to support the electrification-focused energy transition (Exhs. DPU 44-1; AG 13-19).

Although our directives in D.P.U. 21-120 through D.P.U. 21-129, at 233-235, were clear and unambiguous regarding the requirement that each EDC include in its next base distribution rate proceeding a rate proposal for the discontinuance of full revenue decoupling, the record developed in this proceeding, as well as our recent decision in the Unitil base distribution rate case, lead us to conclude that it is reasonable and appropriate for the Company to maintain full revenue decoupling through the five-year PBR-O term (Exhs. NG-CPIP-1, at 213-214; DPU 44-1; AG 13-19). In this regard, we find that the current record does not support a targeted approach to revenue decoupling. We conclude that maintaining full revenue decoupling at this time properly balances the Company's demonstrated efforts to advance the Commonwealth's climate goals with the uncertainty surrounding the timing and extent of widespread acceptance of electrification and decarbonization alternatives. As the transition toward widespread electrification proceeds over the next five years, the Department will assess in the Company's next base distribution rate case whether revenue decoupling – full or targeted – is warranted.

XVI. LOW-INCOME PROGRAM

A. Low-Income Discount

1. Introduction and Background

Pursuant to G.L. c. 164, § 1F, the Department requires distribution companies to provide discounted rates for low-income customers comparable to the low-income discount rate received off the total bill for rates in effect prior to March 1, 1998. See also Expanding Low-Income Customer Protections and Assistance, D.P.U. 08-4, at 36 (2008). In D.P.U. 15-155, the Department determined that a compensating adjustment to the low-income discount rate to comply with G.L. c. 164, § 141[241] would include costs associated with the Renewable Portfolio Standard solar carve out and the Net Metering Recovery Surcharge. D.P.U. 15-155, at 470-471.

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[241] G.L. c. 164, § 141 provides, in part: "In all decisions or actions regarding rate designs, the [D]epartment shall consider the impacts of such actions on … the use of new financial incentives to support energy efficiency efforts. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount."

Further, in D.P.U. 22-22, the Department directed the EDCs to "explore stratifying low-income discount rates in a manner that provides an equitable discount for customers, provides assistance for the most vulnerable customers, and mitigates the potential rate shock for customers that transition from low to moderate income." D.P.U. 22-22, at 471-472.

The Company states that it recognizes that not all customers have the same ability to afford monthly energy bills, and that it is committed to proactively delivering programs to assist low-income customers in identifying and securing energy cost assistance (Exh. NG-CP-1, at 20). National Grid also states that to better serve low-income customers it is important for the Company to understand customers at a deeper level to develop "holistic, equitable solutions to address the root causes of their challenges" (Exh. NG-CP-1, at 20). The Company notes that since the onset of the COVID-19 pandemic, it has increased efforts to support low-income customers, including placing a moratorium on shut-offs and implementing deferred payment agreements (Exh. NG-CP-1, at 20). The Company also notes that, according to a report published by the National Consumer Law Center, more than 750,000 residential customers in Massachusetts were lagging in electric or gas bill payments at the end of December 2021 (Exh. NG-CP-1, at 20-21).

The Company states that in early 2022, it hired E Source, a research, consulting, and data science firm, to conduct an ethnography study ("E Source Study") to better understand its most economically challenged customers across its service territories and to help improve assistance programs for this customer segment (Exhs. NG-CP-1, at 21; NG-CP-4). The Company explains that the E Source Study identified four customer groups based on the degree to which low- to moderate-income customers struggle with their energy bills, and the study also revealed characteristics such as billing and payment behaviors (Exh. NG-CP-1, at 21). The Company states that according to the E Source Study, customers in two groups fell behind on payments for a short period of time before catching up, while customers in the fourth group constantly struggled with large arrearage balances (Exh. NG-CP-1, at 21). The Company further states that this group had higher energy burdens, a higher likelihood of being disconnected, contacted the Company seven times more frequently for payment assistance compared to other groups, and comprised the largest portion of arrearage balances (Exh. NG-CP-1, at 21). The Company states that the E Source Study revealed that there is an opportunity to provide greater assistance to three of the four customer groups through identifying and building innovative solutions to improve interactions and communications with these customers, increasing their home comfort, better managing their energy usage, and accessing payment assistance programs (Exh. NG-CP-1, at 22).

Informed in part by the E Source Study, the Company presents three building blocks of its low-income program approach: (1) internal and external partnerships for cohesive planning, development, and execution across product offerings for low-income customers; (2) products and solutions for improved customer engagement and customer experience; and (3) education and outreach to raise awareness of program offerings and ensure an improved customer centric experience (Exh. NG-CP-1, at 22-23). The Company states that properly targeting low-income households with information about its income-eligibility programs will help expand awareness and program adoption and make customer bills more affordable (Exh. NG-CP-1, at 23).

The Company provides six programs and services currently available to low-income electric customers. First, the Company offers a low-income discount, which is a fixed discount of 32 percent on a customer's entire electric bill for those residential customers on Rate R-2 (Exh. NG-CP-1, at 23). Rate R-2 is available for residential customers with household incomes at or below 60 percent of the Massachusetts statewide median income (Exh. NG-CP-1, at 23). Second, the Company offers an Arrearage Management Plan ("AMP") that permanently forgives a portion of customer arrearages if the customer makes timely payments on a payment plan (Exh. NG-CP-1, at 23). AMPs are open to Rate R-2 customers who owe more than $300 and are at least 60 days overdue on their electric bills (Exh. NG-CP-1, at 23). Third, the Company uses the Low-Income Home Energy Assistance Program ("LIHEAP"), which is a federally funded grant program that assists with home energy bills (Exh. NG-CP-1, at 23). A LIHEAP grant is applied toward a customer's heating bill based on the heating source and income qualification performed by CAP agencies (Exh. NG-CP-1, at 23). Receiving LIHEAP is also a path for a customer to become eligible for Rate R-2 (Exh. NG-CP-1, at 24). Fourth, the Company provides a budget billing option for all residential customers to balance payments across twelve months of the year to offset traditionally high winter heating and summer air conditioning peak bills, making bills more predictable for customers (Exh. NG-CP-1, at 24). Fifth, the Company offers income-eligible energy efficiency measures at no cost up to certain established limits to customers on Rate R-2, as well as income-eligible customers in multi-unit dwellings (Exh. NG-CP-1, at 24). Sixth, the Company complies with the Massachusetts shut-off protection law, which prohibits utility disconnection for non-payment between November 15 and March 15 each year (Exh. NG-CP-1, at 24). The Company states that this shut-off protection is extended year-round to residents aged 65 and over, as well as residents experiencing financial hardship where someone in the home is seriously ill or there is a child under twelve months old living in the home (Exh. NG-CP-1, at 24). The Company states that it promotes its programs through email campaigns, social media ads, and bill inserts, through one-on-one customer conversations with call center agents or customer advocates at in-person engagements, and through CAP agencies that leverage statewide resources from the Massachusetts Executive Office of Housing and Livable Communities ("EOHLC") (Exh. NG-CP-1, at 24-25).

The Company states that it has identified two main areas through which it can further assist low-income customers: (1) a more equitable Rate R-2 discount; and (2) increased enrollment in Rate R-2 (Exh. NG-CP-1, at 25-26). With respect to increased enrollment, the Company proposes to build on successful efforts, such as partnerships with CAP agencies and data-sharing for auto-enrollment, with expanded education and outreach resources and proactive planning to promote low-income programs and services (Exh. NG-CP-1, at 25). The Company estimates that as of September 2023, it has approximately 150,000 customers taking service under Rate R-2 and that approximately 390,000 households accounts in its Massachusetts service territory have incomes at or below 60 percent of the statewide median income (Exhs. NG-CP-1, at 25-26; NG-CP-5).[242] The Company states that national research demonstrates barriers to enrollment could be overcome through expanded resources working together with experienced statewide groups, such as LEAN and CAP agencies (Exh. NG-CP-1, at 26, citing U.S. Department of Health & Human Services, "LIHEAP Research Experiences of Selected Federal

242 National Grid acknowledges that this figure likely overstates the number of customers reachable through the Company's programs given important non-income factors such as rental occupancy in buildings where utilities are included in monthly rents (Exh. NG-CP-1, at 26).

Social Welfare Programs and State LIHEAP Programs in Targeting Vulnerable Elderly and Young Child Households" (published December 1, 2008; current as of June 27, 2019)).

To implement these two main areas of further assistance, the Company proposes: (1) a multi-tier low-income discount for Rate R-2 customers, including new methods for verifying customer eligibility; (2) the hiring of incremental FTEs and implementation of an education and outreach program to increase customer awareness and enrollment; and (3) cost recovery for these new costs via the existing RAAF (Exh. NG-CP-1, at 27).[243]

2. Multi-Tier Low-Income Discount Rate

a. Company Proposal

The Company proposes to replace its current flat 32 percent low-income discount with a five-tiered structure based on federal poverty level guidelines or the statewide median income (Exh. NG-CP-1, at 27). The Company states its proposal is aimed at keeping the electric energy burden for low-income customers at approximately 3.4 percent for all eligible customers by increasing the low-income discount rate offered to customers in lower income brackets (Exh. NG-CP-1, at 26-28).[244] The Company proposes to implement this multi-tier structure no

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243 National Grid also proposed a symmetrical affordability PIM related to the enrollment of new customers on Rate R-2, which is addressed in Section IV.G. above (Exh. NG-CP-1, at 27).

244 The Company bases its 3.4 percent target energy burden on the American Council for an Energy-Efficient Economy's 2020 Energy Burden Report, with the aim to reduce households' home energy burden below the designated high level of six percent (Exh. NG-CP-1, at 28). For gas heating customers, the Company split the six percent between electric and gas bills (Exh. NG-CP-1, at 28). The Company further assumed that LIHEAP distributions were made, resulting in low-income customers having spent 56 percent of their home energy bills on electricity and 44 percent of their home energy bills on gas (Exh. NG-CP-1, at 28). As such, the Company allocated 56 percent of the

later than June 2025 (Exh. NG-CP-1, at 27, 41). The Company states that its proposal represents a more complex, yet equitable, approach to reducing energy burden and advancing equity than the flat low-income discount rate that is currently in place (Exh. NG-CP-Rebuttal-1, at 5). National Grid states that it designed its proposal using a combination of factors that appropriately balances competing policy and customer interests and can be reasonably implemented by the Company (Exh. NG-CP-Rebuttal-1, at 5). The Company states further that the proposal was informed by stakeholder engagement prior to its base distribution rate case filing (Exh. NG-CP-Rebuttal-1, at 5).

The proposal is intended to achieve an electric energy burden of 3.4 percent for eligible customers using 600 kWh per month as follows:

- 32 percent discount for households with incomes between 200 percent of the federal poverty level and 60 percent of the statewide median income;
- 36 percent discount for households with incomes between 150 percent and 200 percent of the federal poverty level;
- 44 percent discount for households with incomes between 100 percent and 150 percent of the federal poverty level;
- 49 percent discount for households with incomes between 75 percent and 100 percent of the federal poverty level; and
- 55 percent discount for households with incomes between zero and 75 percent of the federal poverty level.

six percent energy burden to electricity and derived a target electric burden of 3.4 percent (Exh. NG-CP-1, at 28).

(Exh. NG-CP-1, at 27-28).

The Company used an estimated total LIHEAP benefit of up to $1,600 based on fiscal year 2023 benefit numbers and assumed 40 percent was allocated to electric bills (Exhs. NG-CP-3, Sch. 2; MEDA 4-2 (a)). The Company notes that if LIHEAP benefits were removed from its model, the electric share of home energy burden would decrease to 3.1 percent (Exh. NG-CP-Rebuttal-1, at 25). In addition, National Grid states that it included LIHEAP benefits based on (1) the experience of the Company's New York affiliate, which was instructed by the New York Public Service Commission to include the New York version of LIHEAP benefits in its discount payment calculations, and (2) the Company's broader program for increased education and outreach designed to help enroll as many customers as possible in the LIHEAP program (Exh. NG-CP-Rebuttal-1, at 7).

With respect to its proposed tiers, National Grid states that other assistance programs in the Commonwealth often utilize a zero to 100 percent of the federal poverty level as the lowest tier to establish eligibility for their highest discounts, but the Company subdivided this tier to support customers at the lowest end of the income spectrum (Exh. NG-CP-Rebuttal-1, at 21). The Company further explains that it worked with external stakeholders to ensure that its low-income discount system, which splits the zero to 100 percent federal poverty level tier into a zero to 75 percent tier and a 75 to 100 percent tier, is suitable for use (Exh. NG-CP-Rebuttal-1, at 26). The Company also states that it discussed the tiered low-income discount rate structure with EOHLC and confirmed that it is able to update its systems to accommodate the tiered program (Exh. NG-CP-Rebuttal-1, at 26). The Company also states that it will work with other agencies to address any challenges with implementing the multi-tiered low-income discount system (Exh. NG-CP-Rebuttal-1, at 26).

b. Positions of the Parties

i. Attorney General

While the Attorney General supports National Grid's goal in developing its multi-tier low-income discount proposal, she maintains that it is not designed to meet the Company's stated policy goal of achieving affordable energy burdens for Rate R-2 customers (Attorney General Brief at 153). The Attorney General asserts that the biggest design flaw in the Company's proposal is the assumption that all Rate R-2 customers receive $1,600 in LIHEAP benefits (Attorney General Brief at 153, citing Exh. MEDA-1.0, at 12 (Rev.); Attorney General Reply Brief at 46). The Attorney General maintains that less than 30 percent of Rate R-2 customers receive LIHEAP benefits and few, if any, receive as much as $1,600 (Attorney General Brief at 153, citing Exh. MEDA 4-3; Attorney General Reply Brief at 47-48). Therefore, the Attorney General asserts that including the receipt of LIHEAP benefits in the calculation of discount rates fails to address energy burden for the lowest income households in a meaningful manner, and fails to bring the majority of Rate R-2 customers to affordable energy burdens (Attorney General Brief at 153, citing Exh. AG-RNCP-1, at 55-56; Attorney General Reply Brief at 47-48). Further, the Attorney General contends that removing the assumption of LIHEAP benefits from the Company's calculation would cost residential ratepayers $2.84 per month, which the Attorney General maintains is unlikely to have a notable detrimental impact on energy affordability for moderate-income ratepayers (Attorney General Brief at 154-155, citing Exhs. NG-CP-1, at 27-28; NG-CP-Rebuttal-1, at 6; MEDA-1.0, at 21 (Rev.)).

The Attorney General also argues that the Company could mitigate the cost impact of completely removing the assumption of LIHEAP benefits from its analysis by identifying customers receiving LIHEAP benefits during enrollment and subtracting the average monthly LIHEAP benefit for that customer, based on average payments by income tier or actual payments if possible (Attorney General Brief at 155-156, citing Exh. NG-RNCP-1, at 57). The Attorney General maintains that by incorporating actual LIHEAP benefits, the related cost increase estimated from removing LIHEAP benefit assumptions from its analysis would be reduced (Attorney General Brief at 156).

The Attorney General also recommends that the Department direct the Company to recalculate the low-income discount rate for Rate R-2 customers in its proposed highest income tier to align those customers' energy burdens with those of customers in the other tiers (Attorney General Brief at 156; Attorney General Reply Brief at 51). The Attorney General asserts that the proposed low-income discount for these customers is approximately 20 percent of the estimated costs of the proposed low-income discount program (Attorney General Brief at 156, citing Exh. AG-RNCP-1, at 50). Thus, the Attorney General recommends splitting the highest income tier into two separate tiers, as well as reducing the low-income discount provided to those tiers (Attorney General Brief at 157-158, citing Exh. AG-RNCP-1, at 51). The Attorney General also recommends replacing the Company's highest proposed tier, for customers in a household earning 200 percent of the federal poverty level to 60 percent of the statewide median income receiving a 32 percent discount, with the following structure:

- 15 percent discount for households with incomes between 250 percent of the federal poverty level and 60 percent of the statewide median income; and

- 26 percent discount for households with incomes between 200 percent and 250 percent of the federal poverty level.

(Attorney General Brief at 157, citing Exh. AG-RNCP-1, at 52; Attorney General Reply Brief at 52).

The Attorney General argues that implementing her two tiers would have the dual benefits of creating a more equitable energy burden distribution, as well as substantially and equitably reducing the annual costs of the program (Attorney General Brief at 157; Attorney General Reply Brief at 52). Specifically, the Attorney General asserts that the total annual program costs would be reduced by $12.85 million, or $6.33 per customer (Attorney General Brief at 157, citing Exh. AG-RNCP-1, at 52).

The Attorney General also contends that many low-income households have been receiving the 32 percent discount for years, such that it may be built into their expectations around energy cost and household budgeting (Attorney General Brief at 158). Thus, the Attorney General recommends that the Company phase in the multi-tiered low-income discount rates over two years and provide clear and advance communications about the change to help low-income households gradually adapt to the change (Attorney General Brief at 158, citing Exh. AG-RNCP-1, at 52; Attorney General Reply Brief at 52). Specifically, the Attorney General maintains that the Company should phase down the 32 percent low-income discount rate to 29 percent for the 200 percent to 250 percent of the federal poverty level tier and to 23.5 percent for the 250 percent of the federal poverty level to 60 percent of the statewide median income tier in the first year, followed by a reduction to the Attorney General's recommended levels in the second year (Attorney General Brief at 156, citing Exh. AG-RNCP-1, at 53).[245]

The Attorney General also asserts that the Department should direct the Company to integrate the Attorney General's proposed consumption tiers into the low-income discount rate design (Attorney General Brief at 158, citing Exh. AG-RNCP-1, at 50). The Attorney General argues that integrating these consumption tiers would more effectively direct funding to those who need it (Attorney General Brief at 158; Attorney General Reply Brief at 53). With respect to the assumed monthly consumption for calculating the discount rates, the Attorney General asserts that between 25 to 50 percent of the Company's low-income customers use more than 600 kWh per month, and the proposed discount would be insufficient to bring them to an affordable energy burden (Attorney General Brief at 158, citing Exh. AG-RNCP-1, at 59). According to the Attorney General, 50 percent of the Company's low-income customers consume under 452 kWh per month, while 25 percent of the low-income customers use under 218 kWh (Attorney General Brief at 158, citing Exh. AG-RNCP-1, at 59-60; Attorney General Reply Brief at 53 & n.269). The Attorney General maintains that the proposed discount would provide these customers more assistance than necessary to achieve an affordable energy burden (Attorney General Brief at 158; Attorney General Reply Brief at 53 & n.269). The Attorney General asserts that both the over- and under-compensations represent failures to achieve the stated policy goal (Attorney General Brief at 159; Attorney General Reply Brief at 53 & n.269).

245 In her Reply Brief, the Attorney General suggested that alternatively the reduced low-income discount rates could be phased in over a period of three years (Attorney General Reply Brief at 52).

The Attorney General suggests that the Company could scale the discount levels based on the monthly use based over a few months so that customers who consume significantly above or below 600 kWh per month come closer to the target energy burden (Attorney General Brief at 159, citing Exh. AG-RNCP-1, at 60; Attorney General Reply Brief at 53).

The Attorney General maintains that while the Company raises concerns with respect to the potential complexity of constructing and implementing the Attorney General's proposed consumption tiers, as well as providing communications about the system to customers, the Company provides no support for its statements (Attorney General Brief at 159, 161). Specifically, the Attorney General argues that maintaining data regarding the precise volume of electric consumption for each customer is already an integral part of the billing process (Attorney General Brief at 159). The Attorney General also contends that even if there are communication challenges, instituting the system would provide benefits to customers (Attorney General Brief at 161). The Attorney General rejects any notion that consumption tiers would provide a reduced incentive to lower electric usage, and she asserts that the construction of the discount rate for low-income customers who are already struggling to make ends meet is not the proper place to build in additional incentives to reduce consumption (Attorney General Brief at 159-161).

ii. DOER

DOER generally supports the Company's multi-tiered low-income discount proposal and asserts that it will improve affordability for the most energy-burdened customers (DOER Brief at 63). DOER agrees with the Attorney General's recommended modifications to the low-income discount for customers in the highest income tier, phased in over two years to help reduce challenges with respect to energy costs and household budgeting (DOER Brief at 64).

DOER echoes the concern of other intervenors regarding the inclusion on LIHEAP benefits in National Grid's low-income discount calculations and recommends the Department direct the Company to modify its proposal to exclude LIHEAP benefits (DOER Reply Brief at 7).

iii. Low-Income Network

While the Low-Income Network appreciates the Company's multi-tiered discount rate proposal, the Low-Income Network asserts that there is not enough information in the record on which to base a decision and, accordingly, any proposal for multi-tiered discounts should be explored in a generic setting such as the pending energy burden investigation in D.P.U. 24-15 (Low-Income Network Brief at 1). The Low-Income Network takes issue with National Grid's inclusion of LIHEAP benefits in its proposal and argues that the Company relied "only on the one-year largest Federal Fuel Assistance Benefit in history," and therefore overstates the historical benefits low-income customers have received and calculates a lower rate of discounts than eligible customers actually need (Low-Income Network Brief at 4).

The Low-Income Network also maintains that the Company's proposal does not account for the impact on households converting from relatively inexpensive utility gas heat to the more environmentally friendly electric air source heat pumps (Low-Income Network Brief at 5; Low-Income Network Reply Brief at 1). Specifically, the Low-Income Network asserts that approximately 48 percent of low-income customers that switch from gas heat to electric air source heat pumps would experience home energy bill increases up to 33 percent despite the proposed tiered discounts (Low-Income Network Brief at 5; Low-Income Network Reply Brief at 1-2). The Low-Income Network contends that the lack of consideration of these costs diminishes the Company's support for affordability, equity, or GHG emissions reductions

(Low-Income Network Brief at 4-5; Low-Income Network Reply Brief at 2). Finally, the Low-Income Network disagrees with the Attorney General's recommendation to lower the lowest discount tier as it is contrary to the General Court's mandates of prioritizing affordability and equity (Low-Income Network Reply Brief at 3).

iv. CLF, EDF, Acadia Center

CLF, EDF, and Acadia Center argue that the Department should require the Company to revise its multi-tiered low-income discount proposal (CLF Brief at 16; EDF Brief at 40; CLF, EDF, Acadia Center Reply Brief at 12). Specifically, CLF, EDF, and Acadia Center assert that the Company should omit external variables such as LIHEAP benefits in its calculation of discount rates (CLF Brief at 17, citing Exh. EDF-CLF-JRC-1, at 81; EDF Brief at 42l; CLF, EDF, Acadia Center Reply Brief at 12). CLF, EDF, and Acadia Center maintain that including the LIHEAP benefit results in discount rates that fail to meaningfully address the energy burden for the lowest-income households and fails to bring the majority of the customers to an affordable energy burden (CLF, EDF, Acadia Center Reply Brief at 12). CLF, EDF, and Acadia Center also recommend that the Department require National Grid to reduce the discount level for the highest income tier and divide that tier into two to create more equitable energy burden results across the low-income customer population and substantially reduce the annual cost of the program and its impact on ratepayers broadly (CLF, EDF, Acadia Center Reply Brief at 13, citing Attorney General Brief at 157).

v. MEDA

MEDA agrees with other intervenors' arguments that the assumption that all low-income customers receive LIHEAP benefits underestimates the true energy burdens of the majority of low-income customers (MEDA Brief at 6-7). MEDA also asserts that the Company used historically unrepresentative and disproportionately high LIHEAP appropriations in calculating its low-income discount by assuming fiscal year 2023 benefit levels, and MEDA maintains that LIHEAP benefits for fiscal year 2024 were one-third less than fiscal year 2023 (MEDA Brief at 9, citing Tr. 3, at 403; MEDA Reply Brief at 2-3).

Further, MEDA argues that federal law prohibits counting LIHEAP assistance for any purpose under federal or state law (MEDA Brief at 10, citing 42 U.S.C. § 8624(f)(1)). Specifically, MEDA maintains that the LIHEAP statute provides, in pertinent part, that the amount of any home energy assistance payments shall not be considered income or resources of such household for any purpose under any federal or state law (MEDA Brief at 10, citing 42 U.S.C. § 8624(f)(1)). MEDA asserts that the low-income discount rate exists as a matter of state law and thus inclusion of the LIHEAP benefit in calculating the low-income discount would violate federal law (MEDA Brief at 10, citing G.L. c. 164, § 1F(4)).

MEDA also argues that National Grid's proposed tiers do not align with the existing benefit matrix applied by EOHLC and, therefore, the Company's proposal could add administrative costs and burden to the CAP agencies' process of identifying discount tiers for eligible customers (MEDA Brief at 13). MEDA recommends that the tiers mirror the income tiers associated with the LIHEAP program design, as established by EOHLC (MEDA Brief at 13-14; 20, citing Exh. MEDA-1.0, at 19 (Rev.); MEDA Reply Brief at 4-5). MEDA further recommends that the percentage discounts associated with the tiers be set to achieve the target electricity burden, without an assumed LIHEAP benefit, of 3.4 percent, which would result in the following structure:

- 32 percent discount for households with incomes between 200 percent of the federal poverty level and 60 percent of the statewide median income;
- 32 percent discount for households with incomes between 175 percent and 200 percent of the federal poverty level;
- 32 percent discount for households with incomes between 150 percent and 175 percent of the federal poverty level;
- 42 percent discount for households with incomes between 125 percent and 150 percent of the federal poverty level;
- 53 percent discount for households with incomes between 100 and 125 percent of the federal poverty level; and
- 79 percent discount for households with incomes between zero and 100 percent of the federal poverty level.

(MEDA Brief at 14, citing Exh. MEDA-1.0, at 20 (Rev.); MEDA Reply Brief at 5).

MEDA asserts that in developing its recommended tiers, for Rate R-2 income-eligible households with an electricity burden currently at or below 3.4 percent, it applied a continued low-income discount rate of 32 percent to hold those customers harmless from a reduction in the existing discount (MEDA Brief at 15, citing Exh. MEDA-1.0, at 20 (Rev.)) MEDA also maintains that if the Department removes assumed LIHEAP benefits from the discount rate model calculation, the Company should be directed to increase the percentage discounts for each tier to ensure achievement of an average 3.1 percent electric energy burden per tier (MEDA Brief at 15, citing Exh. MEDA-Surrebuttal-1.0, at 11; MEDA Reply Brief at 4).

MEDA also argues that the Department should require National Grid to adjust the percentage discount within each tier on an annual basis to maintain the 3.1 percent electric energy burden target (MEDA Brief at 21; MEDA Reply Brief at 8). MEDA recommends that this adjustment should be made part of the Company's annual RAAF filing (MEDA Brief at 21; MEDA Reply Brief at 8). MEDA asserts that this adjustment is critical because the Company's proposed CPI Plan will trigger annual adjustments of rates, and because market adjustments will impact the price of electric supply (MEDA Brief at 23; MEDA Brief at 8-9).[246] MEDA further asserts that the administrative burden associated with such an adjustment would be low under MEDA's tiered structure given that it mirrors the EOHLC's benefit matrix (MEDA Brief at 24).

Finally, MEDA recommends that the Department reject the Attorney General's recommendation to recalculate the low-income discount rate for Rate R-2 customers in the Company's proposed highest income tier (MEDA Reply Brief at 6-7). MEDA asserts that while retaining the current 32 percent low-income discount rate for households in the highest income tiers would result in a higher cost than that associated with the Attorney General's recommendation, the electric low-income discount rate remains an essential element of retaining access to affordable service (MEDA Reply Brief at 7-8, citing Exh. MEDA-Surrebuttal-1, at 13-14).

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[246] MEDA's initial recommendation was that annual adjustments should be made to discount rates to maintain an energy burden target of 3.4 percent for all eligible customers; on brief, MEDA revised the recommendation to 3.1 percent (Exh. MEDA-1.0, at 19 (Rev.); MEDA Brief at 5, 15).

vi. Company

National Grid argues that in developing its multi-tiered low-income discount rate proposal, it attempted to balance bringing as many customers as possible below the target 3.4 percent electric burden for customers using 600 kWh per month with minimizing costs of the program to all customers (Company Brief at 455). According to National Grid, most intervenors agree that the Company's proposed multi-tiered low-income discount rate structure is an improvement over the current single tier and, therefore, if the Department approves the proposal, low-income customers will be better served (Company Reply Brief at 61). Nonetheless, the Company asserts that it is amenable to implementing a different low-income discount structure so long as it is reasonable and not overly burdensome or costly to implement (Company Reply Brief at 63).

In this regard, the Company identifies two options that it would deem reasonable (Company Reply Brief at 64). For the first option, the Company proposes that it could "[apply] MEDA's tier design using the Company's proposal, removing estimated LIHEAP payments from the calculation of energy burden …, and modifying the tier thresholds as recommended by MEDA, but retaining a minimum 32 percent low-income discount rate, as recommended by MEDA" (Company Reply Brief at 64, citing MEDA Brief at 13-15). For this option, the Company proposes that discounts would be as follows:

- 32 percent discount for households with incomes between 200 percent of the federal poverty level and 60 percent of the statewide median income;
- 43 percent discount for households with incomes between 150 percent and 200 percent of the federal poverty level;

- 57 percent discount for households with incomes between 125 percent and 150 percent of the federal poverty level;
- 64 percent discount for households with incomes between 100 percent and 125 percent of the federal poverty level; and
- 71 percent discount for households with incomes between zero and 100 percent of the federal poverty level

(Company Reply Brief at 64).

As a second option, the Company proposes that it could "[apply] MEDA's tier designs (except for the maximum discount of 79 percent), but not maintaining a minimum 32 percent discount, and instead allowing the discount levels for customers in 200 to 250 percent [of the federal poverty level] and 250 percent [of the federal poverty level] to 60 percent [of the statewide median income], to drop below the current levels of 32 percent to align the level of net energy burden (after the discount) across the tiers" (Company Reply Brief at 64, citing Attorney General Brief at 156-158; Attorney General Reply Brief at 51-52; DOER Brief at 63-64; EDF, CLF, Acadia Center Reply Brief at 13). For this option, the Company proposes that discounts would be as follows:

- 15 percent discount for households with incomes between 250 percent of the federal poverty level and 60 percent of the statewide median income;
- 29 percent discount for households with incomes between 200 percent and 250 percent of the federal poverty level;
- 43 percent discount for households with incomes between 150 percent and 200 percent of the federal poverty level;

- 57 percent discount for households with incomes between 125 percent and 150 percent of the federal poverty level;
- 64 percent discount for households with incomes between 100 percent and 125 percent of the federal poverty level; and
- 71 percent discount for households with incomes between zero and 100 percent of the federal poverty level.

(Company Reply Brief at 64).

National Grid maintains that the two alternative discount structures would have similar to slightly higher system costs to implement than the Company's original proposal (Company Reply Brief at 65, citing Exh. NG-CP-3, Schs. 2, 4; Tr. 1, at 123-128). Further, National Grid urges the Department to rely on the Company's analysis that was used to support its original proposal rather than MEDA's analysis, as the Company's analysis, even if adjusted as described above, can better take into consideration the "second-order effects"[247] from cost increases in the model (Company Reply Brief at 65).

Despite its willingness to consider alternatives to its original multi-tiered proposal, National Grid disagrees with MEDA's recommendation to amend discount levels annually to maintain the electric energy burden target as part of the annual RAAF filing, as the Company asserts that annual adjustments to discount rates is neither efficient nor practical (Company Reply Brief at 61). Further, the Company rejects the Attorney General's recommendation to

[247] The Company explains that second-order effects are those related to the increase in costs for all customers, including Rate R-2 customers, to expand the size of the Rate R-2 program (Tr. 3, at 479-480).

incorporate a consumption component to the low-income discount rate, due to the complexity of fairly establishing the consumption tiers across a highly diverse customer base with very different usage characteristics, as well as an anticipated shift in energy use towards greater electrification in the coming years (Company Reply Brief at 65, citing Exh. NG-CP-Rebuttal-1, at 7). Finally, National Grid argues that there is no cause to delay important benefits for low-income customers, and there is no reason the Department could not implement the multi-tiered low-income discount rate and make changes after it has been in place for several years (Company Reply Brief at 61, 65). As such, the Company rejects the Low-Income Network's recommendation to defer consideration of these issues to the energy burden investigation in D.P.U. 24-15 (Company Brief at 464-465).

c. Analysis and Findings

In D.P.U. 22-22, at 469, 472, the Department expressed concerns regarding the overall affordability of energy bills and recognized that energy bills have strained many family budgets. The Department noted its interest in discussing and developing policies to address low-income assistance and continuing to examine these issues as appropriate in future dockets. D.P.U. 22-22, at 469-470. Further, the Department stated that the EDCs should explore stratifying low-income discount rates to provide an equitable discount for customers, assist the most vulnerable customers, and mitigate the potential rate shock for customers that transition from low to moderate income. D.P.U. 22-22, at 472. The Department also acknowledged the need for a deeper understanding of the impact energy costs are having on all households and a more in-depth understanding of energy burdens. D.P.U. 22-22, at 472.

The Department commends the Company for responding to the Department's directives in D.P.U. 22-22 by developing a comprehensive and thoughtful proposal to increase resources for income-eligible customers in its service territory. The Company has a long history demonstrating a commitment to providing assistance to low-income customers; in 1978, the Department approved a proposal by MECo to reduce rates for certain elderly low-income customers. Investigation into Low-Income Discount Participation Rate, D.T.E. 01-106, Vote and Order to Open Investigation at 2 (2001), citing D.P.U. 19376. The Low-Income Network also acknowledges that National Grid has been an exceptionally strong partner in developing and implementing energy efficiency programs and measures to protect its low-income customers, as well as other affordability programs, e.g., energy efficiency plans, AMP best practices working group (Low-Income Network Brief at 1-2). While the Low-Income Network recommends that we defer consideration of the Company's proposed changes to the discount rate to our energy burden investigation in D.P.U. 24-15, the Department finds that it is important to implement more immediate efforts to relieve the energy burden experienced by many low-income customers, while exploring additional options in the statewide proceeding. As such, we consider in this proceeding appropriate changes to the Company's multi-tiered low-income discount rate structure.

While the Company currently offers eligible customers a flat 32 percent discount rate, its initially proposed multi-tiered low-income discount rate is calculated to target an electric energy burden of 3.4 percent for all customers enrolled in its residential low-income discount rate class (Exh. NG-CP-1, at 26-28). As a result, the Company's initial proposal included five tiers of discount rates beginning at 32 percent for customers earning 200 percent of the federal poverty level to 60 percent of the statewide median income and increasing with each tier to 55 percent for customers earning zero to 75 percent of the federal poverty level (Exh. NG-CP-1, at 27-28). The Department finds the overall structure of the Company's proposal represents a meaningful improvement to address the burdens faced by many of its lowest-income customers. While the Attorney General and MEDA proposed alternative tier structures, at this time the Department does not find them necessarily superior to the structure posed by the Company. On brief, the Company expressed its willingness to accept an alternative tiered structure to what it initially proposed (Company Reply Brief at 64). After reviewing the record and the arguments of the parties, we conclude that it is reasonable and appropriate for the Company to implement a five-tiered low-income discount structure consistent with the first alternative referenced in the Company's reply brief, and subject to the directives below. We intend to further investigate the structure of a tiered low-income discount rate in D.P.U. 24-15, which may result in future changes to the Company's discount structure approved herein.

The tiered rate structure shall be as follows:

- 32 percent discount for households with incomes greater than 200 percent of the federal poverty level and less than or equal to 60 percent of the statewide median income;
- 43 percent discount for households with incomes greater than 150 percent and less than or equal to 200 percent of the federal poverty level;
- 57 percent discount for households with incomes greater than 125 percent and less than or equal to 150 percent of the federal poverty level;

- 64 percent discount for households with incomes greater than 100 percent and less than or equal to 125 percent of the federal poverty level; and
- 71 percent discount for households with incomes between zero and 100 percent of the federal poverty level.

As discussed above, several intervenors raise arguments regarding the appropriateness of including LIHEAP benefits in the calculation of discount rates when less than 30 percent of Rate R-2 customers as of September 30, 2023 received any amount of LIHEAP benefits (Attorney General Brief at 153, citing Exh. MEDA 4-3; Attorney General Reply Brief at 47-48; Low-Income Network Brief at 4; CLF Brief at 17, citing Exh. EDF-CLF-JRC-1, at 81; EDF Brief at 42l; CLF, EDF, Acadia Center Reply Brief at 12; MEDA Brief at 6-7, 9, citing Tr. 3, at 403; MEDA Reply Brief at 2-3). In response, National Grid acknowledges that the removal of estimated LIHEAP payments from the calculation of energy burden is reasonable (Company Reply Brief at 64). Based on our review of the record and the arguments of the parties, we find that including the receipt of LIHEAP benefits in the calculation of the discount rate is inappropriate at this time and, therefore, we direct the Company to remove the LIHEAP assumption from its discount calculations (Exhs. EDF-CLF-JRC-1, at 80-82; MEDA-1.0, at 16-18 (Rev.); EDF-CDF 1-26; EDF-CDF 1-28; MEDA 4-2; MEDA 4-3; Tr. 3, at 413).[248] The Department intends to further discuss and scrutinize the reasonableness of including non-utility benefits in calculations of a discount rate in our proceeding in D.P.U. 24-15.

248 As we direct the Company to remove LIHEAP benefits from its discount calculations, we need not address whether the inclusion of LIHEAP benefits would violate 42 U.S.C. § 8624(f)(1).

Given that we approve the Company's proposal to maintain its current 32-percent discount for customers in its highest income tier, we find that a phase-in of the highest tier is unnecessary. Moreover, we find it reasonable to approve this 32-percent discount as a default discount for those customers who show proof of participation in a qualified means-tested program but whose income is unknown.

The Department also finds that the multiple additional assumptions and calculations underlying the Company's analysis (i.e., typical bill assumptions, usage assumptions, target electric energy burden) require additional scrutiny and comment by stakeholders not involved in the instant proceeding. We therefore defer ruling on all underlying assumptions to our proceeding in D.P.U. 24-15. In the meantime, the Department directs the Company to implement the new low-income discount rate as soon as practicable, and no later than June 2025, and to provide status updates to the Department every 60 days until such time as the rate is available to customers.

In D.P.U. 24-15, the Department will consider, among other points, the following:

(1) How to develop a target electric energy burden;

(2) How to develop an appropriate average annual bill;

(3) How to develop an appropriate tiering structure;

(4) Whether and how other programs' benefits should be considered;

(5) Whether and how the discount rates should incorporate levels of consumption;

(6) Whether and how to consider electrification, including the impact on cost of customers converting to heat pumps; and

(7) Whether and how to amend discount rates over time.

The Department recognizes that the multi-tiered low-income discount rate, when implemented, will constitute a meaningful bill discount for many income-eligible customers, but we also are mindful of the impacts that increasing the low-income discount rate for some customers may have for ineligible customers, as costs associated with providing a low-income discount rate are recovered from all distribution customers. We recognize the need to balance the impact of increasing a low-income discount rate against the impact on other customers, particularly moderate-income residential and small C&I customers. While the Department finds that the adjustment to the low-income discount rate is reasonable at this time, the Department notes that further adjustments may be required in the future. As noted above, the Department expects to address these issues as part of our investigation in D.P.U. 24-15 and may require additional modifications to the Company's low-income discount rate. The Department acknowledges the attention that numerous intervenors and the Company gave to this issue in this proceeding, which resulted in the productive development of record evidence that informed our decision.

3. Verification, Education, and Outreach Efforts

a. Company Proposal

The Company states that new eligibility mechanisms will be required to support its proposed multi-tiered low-income discount rate (Exh. NG-CP-1, at 31). The Company proposes three methods for verifying customer eligibility, with each considerate of cybersecurity and privacy concerns about collecting detailed customer income data (Exh. NG-CP-1, at 31). The Company states that its first method is enhanced data sharing (Exh. NG-CP-1, at 31).

Specifically, the Company intends to build on auto-enrollment through data-sharing agreements with the Department of Transitional Assistance and CAP agencies that authorize the agencies to share the applicable discount tier for customers based on their records of customers' income from the customer qualification process (Exh. NG-CP-1, at 31). The Company explains that this process involves the relevant agencies sharing a customer's applicable tier for Rate R-2 and not sharing specific income amounts (Exh. NG-CP-1, at 31-32). The Company states that it will try to replicate this process with additional agencies through new data-sharing agreements to automatically enroll new groups of customers who are currently enrolled in other income-verified programs (Exh. NG-CP-1, at 31-32).[249]

For its second method of verification, the Company states that it will continue to directly enroll customers who show proof of participation in a qualified means-tested program into the default 32 percent low-income discount rate, unless additional information is provided to demonstrate that a higher tier should apply (Exh. NG-CP-1, at 32).[250] Customers who show proof of participation in Supplemental Security Income, Supplemental Nutrition Assistance Program, Special Supplemental Nutrition Program for Women, Infants, and Children, MassHealth Standard, CarePlus and Limited Customers, HeadStart, or Veterans Chapter 115 benefits also will be allowed to obtain the second tier low-income discount rate, which the

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249 The Company states that the cost for its first method of verification includes approximately $100,000 for data upgrade expenses required by participating agencies (Exh. NG-CP-1, at 32).

250 A qualified means-tested program is any state or federally funded program that has an eligibility limit of 60 percent of the statewide median income or lower and directly verifies the income of the customers it enrolls (Exh. NG-CP-1, at 32).

Company initially had proposed as 36 percent and the Department approved as 43 percent (Exh. NG-CP-1, at 32-33). The Company states that it will allow direct applicants of Transitional Aid to Families with Dependent Children and Emergency Aid to the Elderly, Disabled and Children to obtain the fourth tier low-income discount rate, which the Company initially had proposed as 49 percent and the Department approved as 64 percent (Exh. NG-CP-1, at 33).[251]

For its third method of verification, the Company proposes to contract a third-party income verifier to confirm customer eligibility using customer income documentation (Exh. NG-CP-1, at 33). The Company maintains that the third-party verifier will rely on customer income documentation to confirm eligibility and place each customer within a discount tier (Exh. NG-CP-1, at 33). The Company would need to issue a RFPs to obtain exact quotes from vendors to ascertain the cost of this method (Exh. NG-CP-1, at 33).

The Company states that it proposes a comprehensive low-income customer strategy to (1) raise awareness and increase enrollment in assistance programs, (2) streamline education and outreach to low-income customers, and (3) develop products and services to improve customer experience (Exh. NG-CP-1, at 34). National Grid further states that low-income customers who are not accessing assistance programs tend to be from under-represented ethnic, cultural, or language groups, so the Company must create a multi-cultural communication plan that extends beyond translations with visuals, messages, and tone of voice that is sensitive to cultural

251 Costs associated with method two include the cost of additional FTEs proposed for the credit and collections team (Exh. NG-CP-1, at 33). The FTEs are discussed in the Order below.

differences to ensure that the program offerings will resonate with audiences of different cultural backgrounds (Exh. NG-CP-1, at 34). The Company states that efforts to expand outreach would include expanding translation efforts, closely working with and possibly incentivizing community-based organizations ("CBOs"), and developing an ongoing omni-channel outreach approach to ensure it is meeting customers where they are located, including utilizing various media and Mass Save marketing efforts (Exh. NG-CP-1, at 34-35). The Company further states that when it hires new advocates, candidates are likely to be individuals from under-represented communities (Exh. NG-CP-Rebuttal-1, at 14). National Grid states that a dedicated budget, dedicated resources, and a comprehensive, long-term outreach and education effort will enable the Company to reach more income-eligible customers with information about available programs and help to address remaining enrollment barriers among these customer segments (Exh. NG-CP-1, at 36).

The Company states that it intends for its proposed multi-tiered low-income discount rate to be operational by June 2025 but cautions that this target date depends on the necessary systems and processes being operational with data-sharing agencies and a third-party income verifier (Exh. NG-CP-1, at 41). As discussed above, the Department directs the Company to implement the multi-tiered low-income discount rate as soon as practicable and no later than June 2025.

b. Positions of the Parties

i. Attorney General

The Attorney General supports National Grid's proposed income verification methods, and she recommends that the Company also implement a two-year customer self-attestation pilot that includes periodic audits to begin when the approved low-income discount rate is offered to customers (Attorney General Brief at 162, 166, citing Exh. AG-CEH-Surrebuttal-1, at 4; Attorney General Reply Brief at 60). The Attorney General cites to other utilities that use self-attestation, as well as the Department of the Treasury's administration of the Homeowner Assistance Fund, and she notes that a significant advantage regarding customer self-attestation of income is that it is simple, easy, and convenient for the customer (Attorney General Brief at 163-164, citing Exhs. AG-CEH-1, at 8; AG-CEH-Surrebuttal-2, at 2-5). The Attorney General further imparts from the Department of the Treasury that selecting the least burdensome approach to income verification creates a more equitable and efficient program that benefits households and communities (Attorney General Brief at 163, citing Exh. AG-CEH-1, at 8-9). The Attorney General also posits that self-attestation may reduce the administrative burden associated with verification of customers requesting to take service under Rate R-2 (Attorney General Brief at 163). To address any concerns related to the potential for fraudulent reporting of income, the Attorney General recommends the Company undertake periodic spot checks to help ensure that the maximum number of eligible customers are served and that funds are not diverted to ineligible customers (Attorney General Brief at 166, citing Exh. AG-CEH-1, at 10). The Attorney General maintains that during the recommended two-year pilot term, the costs of the audit process and incidences of fraud can be compared with the costs for third-party verification (Attorney General Brief at 166). The Attorney General also contends that enrollment via the different pathways should be compared during the two-year pilot term (Attorney General Brief at 166).

The Attorney General also recommends the recertification interval for Rate R-2 occur every two years rather than every twelve months, as she claims that this approach is customer centric and minimizes inconvenience to, and time spent by, the customer (Attorney General Brief at 167, citing Exh. AG-CEH-1, at 18; Attorney General Reply Brief at 60-61, citing Exh. AG-CEH-Surrebuttal-3, at 17; Tr. 12, at 1477). The Attorney General further contends that customers should receive at least two notices, via different channels, when it is time to re-certify, and that customers should be able to complete re-certification digitally by confirming their account and eligibility, or via paper application (Attorney General Brief at 169, citing Exh. NG-CEH-1, at 18). The Attorney General also asserts that the Company should communicate the recertification requirement and timeline as soon as a customer is enrolled in the low-income discount rate so that the customer is aware of the requirement at the outset (Attorney General Brief at 169, citing Exh. AG-CEH-Surrebuttal-3, at 17, 23; Tr. 12, at 1476).

Regarding the Company's approach to verification, enrollment, and program design, the Attorney General recommends six actions (Attorney General Brief at 170). First, the Attorney General states that the Company should align income requirement and verification procedures across programs as consistently as possible so that income-eligible ratepayers can use one verification process to participate in multiple offerings (Attorney General Brief at 170, citing Exh. AG-CEH-1, at 15). Second, the Attorney General recommends the Company use terms that are easy to understand and to which customers can relate, including using an alternative term to "low-income," such as "income-eligible" or "income-qualified" (Attorney General Brief at 170, citing Exhs. AG-CEH-1, at 13; AG-CEH-Surrebuttal-1, at 4). Third, the Attorney General recommends the Company reduce and simplify documentation requirements (Attorney General

Brief at 170, citing Exh. AG-CEH-1, at 14). Fourth, the Attorney General recommends the Company shorten and streamline the verification process to reduce undue burdens and barriers to participation (Attorney General Brief at 171, citing Exh. AG-CEH-1, at 14). Fifth, the Attorney General recommends the Company ensure that third-party consultants verifying eligibility provide only the necessary personal and household data required to enroll customers into the correct tier (Attorney General Brief at 171). Sixth, the Attorney General recommends the Company expand data-sharing agreements to include as many agencies as possible, including Tribal Programs, Family and Youth Services, Medicaid, Special Milk Program, and Summer Food Service (Attorney General Brief at 171, citing Exh. AG-CEH-1, at 16). The Attorney General further recommends that the Department direct National Grid to work with her office, as well as other stakeholders, including LEAN and National Consumer Law Center, to continue to improve the Company's processes to reduce barriers to low-income discount rate enrollment and better serve customers (Attorney General Brief at 172).

The Attorney General supports the Company's approach to centering and investing in increasing awareness of and enrollment in the low-income discount rate and recommends that approval of the proposal be contingent on certain modifications (Attorney General Brief at 173). The Attorney General commends National Grid's commitment to creating a multi-cultural communication plan that extends beyond translations with visuals, messages, and tone of voice that is sensitive to cultural differences to ensure that the Company's program offerings will resonate with audiences of different cultural backgrounds (Attorney General Brief at 173, citing Exhs. NG-CP-1, at 34; AG-CEH-1, at 23). With respect to communications regarding the low-income discount, the Attorney General appreciates that National Grid appears to agree that using simpler language in its communications is essential to effectively reaching eligible customers but asserts that the Company should be more diligent about utilizing language that is concise and easily understandable (Attorney General Brief at 174-175, citing Exhs. AG-CEH-1, at 23; AG-CEH-Surrebuttal-3, at 15).

The Attorney General also recommends that the Company's multi-cultural communication plan include a commitment to partnering with CBOs and CAP agencies to ensure cultural and linguistic appropriateness (Attorney General Brief at 175). In addition, the Attorney General maintains that expanding language access is key to reaching diverse, under-served communities and recommends that the Company's marketing, education, and outreach materials be in the primary language spoken by ratepayers in their homes (Attorney General Brief at 175, citing Exh. AG-CEH-1, at 23-24). The Attorney General recommends that the Company develop and implement a language access plan, including plans to recruit, train, and compensate community agencies and community members to ensure language accessibility across the diverse languages spoken within the Commonwealth (Attorney General Brief at 175, citing Exh. AG-CEH-1, at 34).

The Attorney General further recommends that National Grid integrate principles of equitable community engagement, and she asserts that the Company should make a more detailed plan and specific commitment to partnering with or hiring community members from the under-represented communities they serve to help improve relationships with these communities (Attorney General Brief at 175-176, citing Exh. AG-CEH-1, at 23-30).

Finally, the Attorney General strongly recommends that National Grid be required to provide reasonable compensation (i.e., local market rate) to CBOs, CAP agencies, and community members and experts with which the Company partners (Attorney General Brief at 176). The Attorney General asserts that it is inappropriate and contrary to best practices for the Company to avail itself of the time, labor, and expertise of these organizations and individuals without providing just and reasonable compensation (Attorney General Brief at 176, citing Tr. 12, at 1475–1476).

ii. DOER

DOER states that it supports the Attorney General's recommendations related to National Grid's proposed approach to the discount rate verification and enrollment procedures, as well as those related to the Company's discount rate marketing, education, and outreach plan and best practices for stakeholder outreach (DOER Reply Brief at 8, citing Attorney General Brief at 162-177).

iii. Low-Income Network

The Low-Income Network argues that the Company's current discount eligibility verification is exclusively based on enrollment in means-tested programs, which does not comply with the statutory requirement of G.L. c. 164, § 1F(4) to consider income alone (Low-Income Network Brief at 13-14, citing Exh. LI-NG 2-18; Tr. 1, at 185). According to the Low-Income Network, G.L. c. 164, § 1F(4) requires the Company to put all individuals who are eligible for LIHEAP on the low-income discount rate (Low-Income Network Brief at 13). The Low-Income Network asserts that there is no requirement of categorical eligibility through a program enrollment as long as the income requirement is met (Low-Income Network Brief at 13). Thus, the Low-Income Network contends that the Company has failed to implement current statutory requirements for enrollment eligibility (Low-Income Network Reply Brief at 3).

iv. Company

The Company asserts that its proposal to implement a comprehensive low-income customer segment strategy will increase awareness of and participation in programs to increase low-income customer affordability (Company Brief at 458, citing Exh. NG-CP-1, at 34). The Company recognizes that the Attorney General generally supports the Company's outreach and education program (Company Brief at 459, citing Exh. AG-CEH-1, at 29; Tr. 12, at 1476-1479). With respect to verification and enrollment, the Company accepts the "concept" of the Attorney General's proposal that recertification occur on a two-year cycle (Company Reply Brief at 66). The Company contends, however, that consideration of the Attorney General's self-attestation pilot should be further investigated in D.P.U. 24-15 (Company Reply Brief at 66).

c. Analysis and Findings

The Department has recognized that customer education, marketing, and outreach are crucial to enabling the successful implementation of utility programs. D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 138; Modernization of the Electric Grid, D.P.U. 12-76-B at 2 (2014). Furthermore, the Department acknowledges that stakeholder input on marketing and outreach strategies is valuable, particularly in determining how to engage hard-to-reach customers and underserved and overburdened populations. D.P.U. 21-90/D.P.U. 21-91/D.P.U. 21-92, at 138.

With respect to verification of eligibility, the Department approves the Company's first two methods as proposed: (1) enhanced data sharing, building on auto-enrollment through data sharing with the Department of Transitional Assistance and CAP agencies; and (2) and the continuation of direct enrollment for customers who show proof of participation in a qualified means-tested program into the default 32 percent low-income discount rate, unless additional information is provided to demonstrate that a higher discount tier should apply (Exh. NG-CP-1, at 31-32). The Department defers making a decision regarding the Company's proposed third-party verification process to the proceeding in D.P.U. 24-15. The Department finds that this issue requires additional scrutiny and discussion by all relevant stakeholders, including CAP agencies and CBOs that are not intervenors in the instant proceeding. Any required modifications to the Company's low-income discount rate verification process will be addressed in D.P.U. 24-15.

The Attorney General recommends that the Company also implement a two-year customer self-attestation pilot that includes periodic audits beginning when the approved multi-tiered low-income discount rate is offered to customers (Attorney General Brief at 162, 166, citing Exh. AG-CEH-Surrebuttal-1, at 4; Attorney General Reply Brief at 60). The Attorney General provides reference to successful programs in other states, as well as by the Department of the Treasury's Homeowner Assistance Fund (Attorney General Brief at 163-164, citing Exhs. AG-CEH-1, at 8; AG-CEH-Surrebuttal-2, at 2-5). The Department finds it reasonable that self-attestation may reduce the administrative burden associated with verification of low-income customers requesting service under Rate R-2, but we acknowledge the legitimacy of concerns regarding the potential diversion of funds to ineligible customers related to fraudulent reporting of income (Exh. AG-CEH-1, at 10-11). Therefore, the Department directs the Company to work with the Attorney General and other interested stakeholders to develop a proposal to launch a two-year pilot allowing for self-attestation, with periodic spot checks to help ensure that the maximum number of eligible customers are served and that funds are not diverted to ineligible customers (Exh. AG-CEH-1, at 10-11). Accordingly, the Department directs the Company in a compliance filing no later than six months from the issuance of this Order to propose a two-year self-attestation pilot that includes the following parameters:

(1) A transparent, easy to understand, and efficient self-attestation and enrollment process that includes multi-cultural and multi-lingual communications;

(2) Estimated costs and processes of all aspects of the pilot, including the cost and procedures related to audits;

(3) Twice annual reporting on the costs of the audit process and incidences of fraud so that the costs can be compared with the costs for third-party verification and the cost of enrollment via the different approved methods; and

(4) Summaries of all stakeholders' positions on the discussed topics.

The Attorney General further recommends that the Company amend its recertification process, including changing the term to occur every two years (Attorney General Brief at 167-169, citing Exhs. AG-CEH-1, at 18; Attorney General Reply Brief at 60-61, citing Exh. AG-CEH-Surrebuttal-3, at 17, 23; Tr. 12, at 1476-1477). The Department finds this recommendation is better suited to further review and investigation in D.P.U. 24-15. In addition, the Attorney General provides multiple substantive recommendations with respect to additional efforts the Company could implement, as well as recommendations regarding how the Company interacts with individual communities and CBOs (Attorney General Brief at 170-176, citing Exhs. AG-CEH-1, at 13-16, AG-CEH-Surrebuttal-1, at 4). The Department also finds the numerous recommendations of the Attorney General with respect to additional actions the Company should implement to assist in its verification, enrollment, and program design efforts to warrant further discussion among a larger group of stakeholders in the context of the pending statewide proceeding in D.P.U. 24-15.[252]

With respect to the Low-Income Network's argument that the Company's current discount eligibility verification is exclusively based on enrollment in means-tested programs in violation of G.L. c. 196, § 1F(4), we first note that the statute provides in pertinent part:

> Eligibility for the discount rates established herein shall be established upon verification of a low-income customer's receipt of any means tested public benefit, or verification of eligibility for the low-income home energy assistance program, or its successor program, for which eligibility does not exceed 200 per cent of the federal poverty level based on a household's gross income.

Thus, in addition to establishing eligibility for low-income discount rates through verification that a customer is receiving any means-tested public benefit, G.L. c. 164, § 1F(4) also permits eligibility to be established by verification that a customer is eligible for – but not necessarily receiving – LIHEAP or its successor program. G.L. c. 164, § 1F(4) further provides:

> In a program year in which maximum eligibility for the low-income home energy assistance program, or its successor program, exceeds 200 per cent of the federal poverty level, a household that is income eligible for the low-income home energy assistance program shall be eligible for the low-income discount rates required by this subparagraph.

The current income eligibility for LIHEAP is 60 percent of estimated statewide median income, which means that a household's income that is at or below 60 percent of statewide

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252 These include aligning income requirements across offerings, using terms that are easy to understand, reducing the amount of documentation required, streamlining the verification process, ensuring third-party consultants provide only the necessary details required for enrollment, expanding data-sharing agreements, enhanced collaboration with stakeholders, CBOs, and CAP agencies, expanding language access efforts, integrating principles of equitable community engagement, and providing compensation to CBOs and CAP agencies (Attorney General Brief at 170-176).

median income is also eligible for the low-income discount rates.[253] National Grid's enrollment application form specifies the following as eligibility criteria: "You are currently receiving benefits under a means-tested program (see list below) or you are eligible for Fuel Assistance/the Home Energy Assistance Program (HEAP), or its successor program" (Exh. LI-NG 2-18, Att. 2). The application form language suggests that National Grid does not limit proof of eligibility to receipt of benefits from other means-tested programs. On the other hand, National Grid stated that demonstrations of eligibility are based on enrollment in means-tested programs (Exhs. NG-CP-1, at 31; LI-NG 2-3(b), (h)(ii); LI-NG 2-18(b)(i); Tr. 1, at 185). More specifically, the Company stated that, for purposes of qualifying customers for the low-income discount rate, "the Company relies on demonstrations of receipt of [certain specified] benefits" and "and does not establish eligibility for the discount through other means" (Exh. LI-NG 2-3(b), (h)(ii)).

While it is possible that enrollment in another means-tested benefit is the only way to show eligibility for LIHEAP without actually receiving LIHEAP benefits, the evidence is not clear on this point. Thus, to the extent that National Grid is requiring that customers be enrolled in LIHEAP or another means-tested benefit to establish eligibility for low-income discount rates, we direct the Company to review its procedures and update its practices to ensure that eligibility for low-income discount rates may be established merely by verification of eligibility for LIHEAP (i.e., verification of income at or below 60 percent of the statewide median income), in compliance with G.L. c. 164, § 1F(4).

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253 https://www.mass.gov/doc/fy-2025-heap-income-eligibility-benefit-chart-june-30-2024/download (last visited on July 30, 2024).

4. Cost Recovery

a. Company Proposal

The Company proposes to recover all incremental costs associated with its proposed low-income assistance programs through the RAAF (Exh. NG-CP-1, at 42). The costs associated with the Company's proposed assistance programs include the revenue shortfall from the multi-tiered low-income discount rate, system upgrade costs, outreach and education costs, third party verification costs, and the costs for dedicated FTEs (Exh. NG-CP-1, at 42-44).

Currently, the Company recovers the cost of the revenue shortfall from the current discount to Rate R-2 customers, as well as the incremental costs associated with the operation of the Company's AMP offered to qualifying customers through the RAAF (Exh. NG-CP-1, at 42). The Company estimates costs related to the revenue shortfall from the multi-tiered low-income discount rate for current Rate R-2 customers to range from approximately $11.0 million in the first year of the program to $32.8 million in the fifth year of the program and annually thereafter (Exhs. NG-CP-2; NG-CP-3, Sch. 4). The Company estimates costs related to the revenue shortfall from the low-income discounts for new enrollment and second-order effects to range from approximately $3.5 million between November 2024 and October 2025, increasing annually to approximately $22.5 million between November 2028 and October 2029 (Exh. NG-CP-3, Sch. 4).

National Grid estimates the one-time expense to upgrade its billing systems to implement its proposed multi-tiered low-income discount is $1,169,000, which includes $100,000 for one-time data upgrades required by participating agencies (Exhs. NG-CP-1, at 32; NG-CP-2). With respect to its outreach efforts, the Company estimates costs of $3,000,000 per year to implement its proposed annual outreach and education program, which includes $1,150,000 for media spend across television, radio, and out-of-home/place-based media, $600,000 for digital media expenses, $500,000 to $750,000 for the costs of in-person customer and CAP agencies' events with on-site interpreters, and $500,000 for the cost of production of all outreach and education materials in the top three to five languages to ensure a "multi-cultural transcreation/in-culture plan and process" that includes work with CBOs, translation agencies, and concept testing with in-person focus groups (Exhs. NG-CP-1, at 36-37; NG-CP-2; NG-CP-7). Regarding the costs for the Company's proposed three methods for verifying customer eligibility, National Grid estimates costs of $175,000 in the first year, and $225,000 for each year thereafter (Exh. NG-CP-1, at 44).

National Grid states that at present, there is only one FTE dedicated to low-income and environmental justice population strategy development, research, and program design, and six customer advocates dedicated to assisting the Company's most economically challenged customers, who cover both the Massachusetts electric and gas service territories (Exh. NG-CP-1, at 38). National Grid states that this level of staffing is not sufficient to support the Company's necessary and comprehensive low-income customer segment strategy (Exh. NG-CP-1, at 39). The Company therefore proposes to permanently add ten additional FTEs to support its increased efforts described above (Exh. NG-CP-1, at 38-40). National Grid states that seven low-income dedicated FTEs will support the Company's expanded efforts for its Massachusetts electric residential customers, including three customer advocates; one marketing, education, and outreach analyst; one data analyst; one payment assistance administrator; and one segment analyst (Exh. NG-CP-1, at 38). The Company further proposes to add three FTEs, consisting of two revenue service associates and one billing operations senior analyst, dedicated to implementing the Rate R-2 multi-tiered low-income discount rate (Exh. NG-CP-1, at 39). The Company states that the ten incremental FTEs do not reflect a normal ebb and flow of staffing but represent a significant and permanent increase in low-income program staffing (Exhs. NG-CP-1, at 39-40; NG-CP-Rebuttal-1, at 19; Tr. 3, at 381-382). The Company also states that it expects the needs of low-income customers to evolve, and that the proposed FTEs will continue to reevaluate efforts targeted to low-income customers and provide payment assistance support (Exh. NG-CP-1, at 41-41). National Grid states that recovering the costs for the proposed ten FTEs through the RAAF instead of base distribution rates will provide greater transparency into the Company's low-income initiatives and enable stakeholders to track and evaluate the Company's increased efforts (Exh. NG-CP-1, at 42-43). The Company states that the cost of the additional ten FTEs is approximately $1.235 million (Exhs. NG-CP-1, at 39; NG-CP-3).

The Company states further that it proposes to cap the amounts of annual education and outreach spending, as well as associated FTE labor costs collected through the RAAF, at $4.25 million per year. The Company does not propose to cap recovery related to implementation of the multi-tiered low-income discount rate, including internal and external systems costs and credit and collections FTEs, given that these are preliminary high-level estimates at this time (Exh. NG-CP-1, at 43).

The Company states that in the first year after approval of its proposals, i.e., November 2024 through October 2025, the total incremental cost of its proposals is approximately $20 million (Exh. NG-CP-3, Sch. 4). The Company estimates that costs over the following four years will increase to $46.5 million, $51.0 million, $55.5 million, and $60.0 million, respectively (Exh. NG-CP-3, Sch. 4).

Finally, the Company states that if the Department approves the proposed multi-tiered low-income discount rate, FTEs, system upgrade costs, outreach and education funding, and third-party verification costs and, as a result, enrollment increases by 15 percent, the total program costs would increase from the current $113 million to $173 million in the fifth year (Exhs. NG-CP-1, at 44; NG-CP-3, Sch. 2). The Company states that this corresponds to an average monthly bill increase of $2.27, or 1.2 percent, for an average residential customer by the fifth year of the low-income assistance programs (Exh. NG-CP-1, at 45; RR-DPU-9, Att.).

b. Positions of the Parties

i. Attorney General

The Attorney General maintains that billing system reprogramming costs are one-time costs and should be annualized over five years (Attorney General Brief at 187). Moreover, the Attorney General maintains that FTEs and marketing costs associated with the administration of the low-income assistance programs are O&M expenses that historically have been, and should continue to be, recovered through base distribution rates (Attorney General Brief at 186).

The Attorney General asserts that when the Department considers whether to allow a new reconciling mechanism, the Department considers specific criteria, such as whether the costs at issue are volatile in nature, large in magnitude, neutral to fluctuations in sales, and beyond the company's control (Attorney General Brief at 186, citing D.P.U. 19-120, at 287). The Attorney General maintains that the annual costs for the administrative expenses proposed by the Company will be relatively consistent from year to year and will therefore not be volatile in nature (Attorney General Brief at 186, citing Exh. NG-CP-2). Therefore, the Attorney General asserts, all administrative costs related to the low-income assistance programs are recurring and consistent and do not satisfy the standard for unique treatment via a reconciling mechanism (Attorney General Brief at 187). The Attorney General further posits that the proposed administrative costs fail to meet the other criteria because: (1) the costs are quite small compared to the Company's proposed cost of service and therefore not large in magnitude; (2) the costs will not change with fluctuations in sales; and (3) the majority of the costs for the ten FTEs and the marketing, education, and outreach plan are directly related to the Company's planned outreach and are within the Company's control (Attorney General Brief at 187).

ii. DOER

DOER objects to the costs of the permanent increase in FTEs being recovered through the RAAF (DOER Brief at 63). DOER maintains that instead, these costs should be recovered through base distribution rates as recovery of costs through reconciling factors is not warranted for permanent increases in the Company's distribution-related staff, and it serves to further dilute the effect of rate designs applied only to base rates (DOER Brief at 63).

iii. Low-Income Network

The Low-Income Network recommends the Department defer review of the Company's low-income assistance proposals to D.P.U. 24-15 (Low-Income Network Brief at 2). The Low-Income Network asserts that it opposes proposals to charge low-income customers for an unproven need to expand low-income discount outreach, at unknown costs, beyond the existing admittedly successful outreach by others (including the Low-Income Network), while the Company has failed its current statutory outreach obligations (Low-Income Network Brief at 2, 10-11). The Low-Income Network also maintains that recovery of the Rate R-2 discount costs from discount-rate eligible customers through the RAAF is contrary to the direction provided by the General Court (Low-Income Network Brief at 9, citing G.L. c. 164, § 1F (4)(i)).

iv. MEDA

MEDA asserts that it does not object to the cost of the discount rate being recovered through the RAAF, given the potential volatility of customer enrollments (MEDA Brief at 53; MEDA Reply Brief at 21). MEDA, however, maintains that the recovery of the Rate R-2 discount costs from discount-rate eligible customers is prohibited by the provisions of G.L. c. 164, § 1F(4)(i) (MEDA Reply Brief at 21). MEDA asserts that the statute clearly provides that the cost of low-income discounts are to be included in rates charged to all other customers and maintains that the word "other" in this phrase implies all distribution customers other than those customers receiving the discount (MEDA Reply Brief at 21, citing G.L. c. 164, § 1F (4)(i)). MEDA also objects to the Company's proposal to recover costs associated with its outreach efforts and additional FTEs via the RAAF (MEDA Brief at 52-53; MEDA Reply Brief at 20-21). MEDA argues that these efforts are inextricably linked to the Company's existing obligation as a monopoly electric utility provider and represent expenses that are within the Company's control (MEDA Brief at 53; MEDA Reply Brief at 21). MEDA asserts that these costs instead should be folded into the Company's base distribution rates (MEDA Brief at 53; MEDA Reply Brief at 21).

v. Company

The Company states that it proposes to collect all proposed incremental low-income program costs through the RAAF (Company Brief at 462, citing Exh. NG-CP-1, at 42). The

Company asserts that this proposal is intended to provide greater transparency and dedicated recovery for these costs (Company Brief at 462). The Company further asserts that the costs are proposed to be recovered through the RAAF rather than base distribution rates based on the June 2025 timeline to implement the low-income proposal, including the multi-tiered low-income discount rate, data-sharing system upgrades, and hiring of incremental employees (Company Brief at 462, citing Tr. 3, at 370-371; 380-381; 419-420; 469-470; 486-487). The Company maintains that it proposes to cap the recovery of annual education and outreach spending as well as associated FTE labor costs to $4.25 million but does not propose to cap recovery for implementation of the multi-tiered low-income discount rate, including internal and external system costs and credit and collections FTEs, given that these costs are preliminary high-level estimates (Company Brief at 463, citing Exh. NG-CP-1, at 43). The Company maintains that it would support recovery of such costs via an addition to the approved base distribution rates in this proceeding, instead of the RAAF, even though the Company has not yet incurred these costs (Company Reply Brief at 67).

The Company asserts that it requires an incremental increase in funding of $3 million per year to support its multi-cultural communication plan, the creative development, execution, and testing of in-language/transcreated assets, and an omni-channel outreach approach (Company Brief at 459, citing Exh. NG-CP-1, at 36-37). The Company argues that its ten incremental FTEs proposal will support its expanded efforts and does not reflect a normal ebb and flow of staffing levels but represents a significant and permanent increase in low-income program staffing (Company Brief at 459-461, citing Exh. NG-CP-1, at 38-40; Tr. 3, at 381-382). Finally, the Company asserts that the Low-Income Network's recommendation against incremental spending for marketing, education, and outreach initiatives, pending further regulatory process, would unreasonably delay the benefits for customers from such spending (Company Reply Brief at 67).

c. Analysis and Findings

Pursuant to G.L. c. 164, § 1F(4)(i), the Department requires that distribution companies provide discounted rates for low-income customers and that each distribution company "conduct substantial outreach efforts to make said low-income discount available to eligible customers." Further, G.L. c. 164, § 1F(4)(i) states "the cost of such discounts shall be included in the rates charged to all other customers of a distribution company." Prior to the Department's decision in D.T.E. 01-106-C/D.T.E. 05-55/D.T.E. 05-56, lost revenues from the traditional low-income discount program were designed to be recovered from all customers through base distribution rates. D.T.E. 01-106-C/D.T.E. 05-55/D.T.E. 05-56 at 8, citing D.T.E. 03-40, at 385. In D.T.E. 01-106-B at 9, the Department stated that in a company's next base distribution rate case it may recover revenues lost as a result of the low-income discount in its next reconciling filing for electric companies.

In the present case the Company requests to recover certain costs associated with its low-income assistance programs. Specifically, the Company seeks to increase its RAAF collections to reflect discount costs for current and new enrollees estimated to be approximately $11 million in the first year after approval of the proposals to approximately $48 million in year five, as well as approximately $1.169 million in one-time system upgrade costs, $3.0 million annually for outreach and education costs, $525,000 annually for third-party verification costs, and $1.235 million annually for ten additional FTEs (Exhs. NG-CP-1, at 44; NG-CP-3, Sch. 4). The Department finds that the Company may continue to collect the cost of low-income discounts, which will likely be higher than the Company's estimates due to the directives in this case regarding the calculation of the discounts, through its RAAF. Regarding the Low-Income Network's and MEDA's concerns with the recovery of the Rate R-2 discount costs from discount-rate eligible customers, the Department finds it appropriate to defer this issue for further review and investigation in the energy burden proceeding, D.P.U. 24-15. With respect to the non-discount costs discussed above, the Department is not convinced that these costs are appropriate for recovery in a reconciling mechanism. When the Department considers whether to allow a new reconciling mechanism, we consider specific criteria, such as whether the costs at issue are: (1) volatile in nature; (2) large in magnitude; (3) neutral to fluctuations in sales; and (4) beyond the company's control. D.P.U. 19-120, at 287-288; D.P.U. 10-55, at 66 n.43; D.T.E. 05-27, at 183-186; D.T.E. 03-47-A at 25-28, 36-37. Although the Company's RAAF is not new, the Company seeks to expand it and recover a variety of new costs through the mechanism. With respect to the first criterion, the proposed non-discount costs do not appear to be volatile. The Company has not presented a range of costs, rather it has presented distinct, albeit preliminary in some cases, costs (Exhs. NG-CP-1, at 44; NG-CP-3, Sch. 4). Next, the proposed non-discount costs represent less than one percent of the Company's total proposed revenue requirement and, therefore, the costs are not large in magnitude (Exh. NG-RRP-2, Sch. 1 (Rev. 4)). Third, the proposed non-discount costs are neutral to fluctuations in sales. Finally, with respect to the fourth criterion, the proposed non-discount costs are not beyond the Company's control, as it is responsible for assessing all costs related to these planned investments before incurring them. Further, the Company's costs of current employees serving similar customer-related functions to the prospective FTEs are recovered in base distribution rates, not in the RAAF (Tr. 3, at 368-370). Therefore, the Department denies the Company's request to recover its proposed non-discount costs via the RAAF.

Nonetheless, to encourage timely implementation of its multi-tiered low-income discount rate, the Department finds that the Company's proposal to expand its verification, education, and outreach efforts need to be implemented in a similarly timely manner, and as such warrant a clear path to cost recovery (Tr. 3, at 384, 418-419, 468-470, 472, 486-487). The Department is not convinced by the Low-Income Network's argument to delay implementation of the new efforts for further examination in D.P.U. 24-15. Thus, the Department allows the Company to request recovery for such non-discount costs as part of its first PBR rate adjustment filing. Specifically, with respect to system upgrade costs, the Company may request recovery of up to the proposed $1.169 million for actual costs incurred, subject to prudency review of appropriate documentation, to be amortized over the remainder of the PBR term. With respect to annual education and outreach costs, as well as costs related to the proposed incremental FTEs,[254] the Department allows the Company to request recovery of up to $3 million and $1.235 million, respectively, for actual costs incurred to meet the statutory requirement to conduct substantial outreach, subject to prudency review of appropriate documentation, for annual recovery over the remainder of the PBR term. With respect to the directed self-attestation pilot, the Department will also allow the Company to request recovery of actual costs incurred, subject to prudency

254 The Department expects the Company to leverage all possible efficiencies that can be gained by cross-training and educating staff on verification, education, and outreach efforts for all Company program options that benefit income-eligible customers across its organization. Further, the Department expects the Company to develop systems to ensure that customers receive efficient services and from as few contacts as possible to avoid repetition and confusion.

review of appropriate documentation, for annual recovery or amortization as appropriate in the first PBR rate adjustment filing.

B. Retroactive Application of Discount Rate

1. Introduction

In its testimony, MEDA recommends retroactive application of the low-income discount rate (Exh. MEDA-1.0, at 26 (Rev.)). MEDA explains that the National Consumer Law Center previously reached agreements with each EDC and LDC to retroactively apply the low-income discount rate in limited circumstances and subject to specified protocols (Exh. MEDA-1.0, at 26 (Rev.)). The protocol required that a customer's advocate contact a designated company contact to explain and document the basis justifying the request (Exh. MEDA-1.0, at 26 (Rev.)).

In response to complaints reported by National Consumer Law Center that National Grid was not consistently responding to such requests, MEDA sought additional information from the Company during the instant proceeding (Exhs. MEDA-1.0, at 27 (Rev.); MEDA 1-4; MEDA 5-1; MEDA 6-1). According to MEDA, the Company is exercising its discretion in deciding not to apply the low-income discount rate retroactively to prevent abuse and ensure customers are treated equitably (Exh. MEDA-1.0, at 27-28 (Rev.) citing Exh. MEDA 6-1). Thus, MEDA recommends the Department direct the Company to favorably respond to such requests when the customer's advocate demonstrates that the customer has been income-eligible for the low-income discount rate for a period of time prior to the actual application (Exh. MEDA-1.0, at 28 (Rev.)).

Further, MEDA recommends that a customer who becomes eligible for the low-income discount by receiving LIHEAP benefits in a particular fuel program year be placed on the low-income discount rate as of October 1 of that fuel year, regardless of when in the fuel year the CAP agencies advise the Company that the customer is eligible for LIHEAP benefits (Exh. MEDA-1.0, at 29 (Rev.)). MEDA recommends that the Department direct the Company, to the extent necessary, to develop the capability to perform this task for its customers (Exh. MEDA-Surrebuttal-1.0, at 16).

2. Positions of the Parties

a. Intervenors

MEDA argues that there is confusion and a lack of clarity around retroactive application of the low-income discount, as the Company currently does not have any written policies, documents, or other materials related to the retroactive application of the low-income discount rate" (MEDA Brief at 27, citing RR-AG-15). The Attorney General shares this concern and claims that the lack of transparency and formal policy surrounding retroactive application of the discount compromises the Company's ability to provide the benefit consistently and equitably and deprives CAP agencies, CBOs, and other customer advocates of the opportunity to advocate for and acquire the full range of benefits for which those they are helping are eligible (Attorney General Reply Brief at 56). Therefore, MEDA and the Attorney General, with support from DOER, recommend that the Department direct the Company to develop clear, written policies for applying discounts retroactively, and communicate those policies to employees, customers and their advocates (Attorney General Reply Brief at 56; DOER Reply Brief at 7; MEDA Brief at 27; MEDA Reply Brief at 9-10). MEDA maintains that such policies should include: (1) the designation of the person at the Company to whom such requests should be directed; (2) clarity regarding who can make the request; (3) any supporting documentation that may be required;

and (4) the time frame for how far back the bills can be retroactively adjusted (MEDA Brief at 27-28, citing Exhs. MEDA-Surrebuttal-1.0, at 15; MEDA-CP 1-4; RR-MEDA-2). MEDA recommends that, if necessary, the Department direct the Company to file a report with an estimate of the cost and lead time (MEDA Brief at 29; MEDA Reply Brief at 10). MEDA maintains that low-income customers should not be deprived of this valuable benefit due to how the Company chose to set up its customer service system (MEDA Brief at 29).

b. Company

The Company asserts that it is willing to document and communicate a formal policy for retroactive application of the low-income discount rate, in line with how the Company has historically handled those requests (Company Reply Brief at 67-68). National Grid argues, however, that there is insufficient evidence on the record for the Department to properly evaluate the billing system change costs necessary to apply the low-income discount rate retroactively to October 1 of any fuel assistance year, as proposed by MEDA (Company Reply Brief at 68).

3. Analysis and Findings

MEDA requests that the Department issue two specific directives to the Company: (1) to develop written policies for applying the low-income discount rate retroactively, in individual cases; and (2) that customers receiving LIHEAP in a particular fuel year should be placed onto the low-income discount rate as of October 1 of that fuel year, regardless of when in the fuel year the Company is advised by the CAP agency that the household is LIHEAP eligible (MEDA Brief at 27-29). The Department finds it critical for the Company to develop clear, written processes for all public-facing policies. All policies that impact customers and the rates they pay should be clearly documented and easily accessible. Therefore, the Department directs the Company to develop a clear, accessible, plain language written policy regarding the retroactive application of the low-income discount rate that is responsive to MEDA's recommendations. The Company shall file such a policy with the Department in a compliance filing no later than 60 days after the date of issue of this Order.

MEDA's second recommendation is that a customer receiving LIHEAP in a particular fuel year should be placed onto the low-income discount rate as of October 1 of that fuel year, regardless of when in the fuel year the CAP agencies advise the Company that the customer is LIHEAP eligible (MEDA Brief at 28-29). Because this proposal would affect all the Massachusetts EDCs and LDCs, the Department finds it appropriate to defer a decision on the recommendation to allow further review and investigation in the pending energy burden investigation in D.P.U. 24-15.

XVII. TARIFF CHANGES

A. Solar Cost Adjustment Provision

1. Introduction

On June 28, 2014, the Department approved the Company's petition for pre-approval to construct, own, and operate solar facilities that would generate up to 20 MW of electricity, i.e., Solar Phase II program.[255, 256] Massachusetts Electric Company and Nantucket Electric

[255] In accordance with G.L. c. 164, § 1A(f), EDCs may construct, own, and operate solar generation facilities and seek approval for cost recovery for those facilities from the Department, subject to certain limitations.

[256] On October 3, 2009, the Department approved the Company's five MW Solar Phase I program. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 09-38 (2009). The Solar Phase I generation facilities were incorporated into base distribution rates in D.P.U. 15-155 (Exh. DPU 28-1). See D.P.U. 15-155, at 528 & Exh. NG-RRP-1, at 19, 41.

Company, D.P.U. 14-01 (2014). On December 29, 2016, the Department pre-approved the Company's Solar Phase III program, which allowed 14 MWs of additional solar generation facilities. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 16-104 (2016). Additionally, the Department approved the inclusion of energy storage at these facilities under both programs. D.P.U. 16-104, at 5, 11; Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 15-134, at 9-10 (2016). As of June 30, 2018, National Grid had constructed and placed into service 18 Solar Phase II generation facilities and one energy storage facility; and, as of December 2021, the Company had constructed and placed into service six Solar Phase III facilities and two energy storage facilities. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-16, at 2 (2022); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 22-03, at 2 (2022).

The Company's existing Solar Cost Adjustment Provision ("SCAP") tariff, M.D.P.U. No. 1477, provides for annual cost recovery filings that present the annual revenue requirement associated with the Solar Generation Facilities[257] not otherwise recovered though base distribution rates and the reconciliation of the annual revenue requirement approved by the Department in the prior year to the actual amount of revenue billed to customers through the Solar Cost Adjustment Factor ("SCAF"), plus any credits for net proceeds associated with:

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[257] Solar Generation Facilities are defined as (1) the Company's investment in the equipment in solar DG systems necessary for the generating alternating current power, including ancillary equipment and (2) solar generation with integrated battery storage. M.D.P.U. No. 1477, at Sheets 2-3.

(1) energy sales to the ISO-NE energy markets;[258] (2) sales of Renewable Energy Certificates ("RECs") or the market value of RECs used to comply with the Company's Renewable Portfolio Standard requirement; and (3) bidding the capacity of the Solar Generation Facilities capacity bid into the ISO-NE Forward Capacity Market. M.D.P.U. No. 1477, at Sheet 1. Schedule 1 of the tariff identifies the Solar Generation Facilities subject to the tariff requirements. M.D.P.U. No. 1477, at Sheet 3 & Sch. 1.

Pursuant to National Grid's existing SCAP tariff, as Solar Generation Facilities are constructed and placed into service, the Company files for adjustments to its SCAFs every six months to reflect the partial year revenue requirement of the new solar generation facilities. M.D.P.U. No. 1477, at Sheet 2. As noted above, the Company also reconciles the SCAFs on an annual basis to recover the annual revenue requirement of the facilities not otherwise recovered through its base distribution rates. M.D.P.U. No. 1477, at Sheets 1-2.

The Department previously approved the incorporation of twelve of the Company's Solar Phase II facilities into base distribution rates effective October 1, 2019. D.P.U. 18-150, at 203. The Company continues to use the SCAP tariff to recover costs of six remaining Solar Phase II and six completed Solar Phase III projects and credits customers for associated revenues. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-02, at 2 (February 21, 2024).

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[258] Company-owned solar facilities approved by the Department are registered with ISO-NE, and the Company sells the energy output into ISO-NE's energy markets. D.P.U. 16-104, at 7, 11; D.P.U. 14-01, at 14, 20. The revenue from these sales are returned to customers through the SCAF, a component of the Company's SCAP tariff. D.P.U. 16-104, at 17, 22; D.P.U. 14-01, at 14, 20.

2. Company Proposal

In the instant proceeding, the Company proposes to transfer cost recovery associated with the six remaining Solar Phase II facilities and six Solar Phase III facilities from the SCAF to base distribution rates, effective November 1, 2024, and to remove them from Schedule 1 of the SCAP tariff (Exh. NG-PP-1, at 47-48; proposed M.D.P.U. No. 1535, at 4). Specifically, the Company's proposed adjustment includes the CY 2024 revenue requirements for Solar Phase II and Phase III generation facilities, which total $9,005,608, to be transferred into base distribution rates in this proceeding (Exh. NG-RRP-2, Sch. 1, at 1 (Rev. 4)). The Company provided an amended SCAP tariff to reflect the proposed changes to the distribution revenue allocators and incorporate a credit through the SCAF to customers for net proceeds associated with the Clean Peak Energy Certificates ("CPECs") and the market value of CPECs used to comply with the Clean Peak Energy Portfolio Standard established in G.L. c. 25A, § 17(c) and 225 CMR 21.00 (Exh. NG-PP-1, at 47; proposed M.D.P.U. No. 1535). National Grid also proposes to continue the SCAP tariff for the purposes of recovering costs associated with a Solar Phase III generation facility in Grafton, Massachusetts that was not placed in service at the time of the Company's filing and, therefore, was not included in the list of facilities subject to transfer to base distribution rates in this proceeding (Exh. DPU 12-1).[259] The Company reiterated its proposals on brief (Company's Brief at 263). No other party addressed the Company's proposals on brief.

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[259] During the proceeding, the Company noted that it expected this facility to be placed in service on June 30, 2024 (Exh. DPU 12-1). There is no additional information in the record regarding the status of this facility.

3. Analysis and Findings

The Department has reviewed the record supporting the Company's proposal to transfer the costs associated with the six Solar Phase II facilities and six Solar Phase III facilities from the SCAF to base distribution rates effective November 1, 2024 (Exhs. NG-PP-1, at 47-48; NG-RRP-2, Sch. 1, at 1 (Rev. 4); proposed M.D.P.U. No. 1535). The Department previously determined that the Company acted prudently in undertaking the construction of the Solar Phase II and Phase III facilities and that the facilities were used and useful in providing service to customers prior to the end of the test year. D.P.U. 22-16-A at 9-10; D.P.U. 21-104-A; at 16-17; D.P.U. 21-25-A at 8; D.P.U. 20-93-A at 8; D.P.U. 19-28-A at 7; D.P.U. 18-93-A at 9; D.P.U. 18-23-A at 7. Accordingly, we need not review the investments for a prudency or in-service determination. The Department also previously approved each project's costs for compliance with spending cap requirements, and we were satisfied with the results. D.P.U. 21-104-A at 18-19; D.P.U. 18-93-A at 9; D.P.U. 16-104, at 19-22; D.P.U. 14-01, at 44.

As noted above, the Company proposes to transfer the CY 2024 revenue requirements for Solar Phase II and Phase III generation facilities, which total $9,005,608, into base distribution rates in this proceeding (Exh. NG-RRP-2, Sch. 1, at 1 (Rev. 4)). These costs include the return and income taxes on rate base, depreciation expenses, O&M expenses, lease expenses, and property taxes as proposed in D.P.U. 23-07, minus the sum of the interconnection credits for three Solar Phase II facilities as filed in D.P.U. 22-12 (Exh. WP NG-RRP-2, at 1). D.P.U. 23-07, Exhs NG-1, at 12, JNR-1, at 2.

Given that the six remaining Solar Phase II and six Solar Phase III costs were prudently incurred, the facilities are used and useful in providing service to customers, and the total investments are below their respective authorized spending caps, we find it reasonable, appropriate, and consistent with precedent to transfer the facilities to National Grid's rate base and allow the Company to recover the unrecovered balance through base distribution rates, and to remove from Schedule 1 of the SCAP tariff, the list of completed six Solar Phase II and six Phase III facilities. D.P.U. 18-150, at 203. In addition, the Department approves the Company's proposal to amend its SCAP tariff to add a credit to customers for revenue from the CPECs.

Finally, although the Department approves the proposal to move costs associated with the Solar Phase II and Solar Phase III facilities into base distribution rates, we find it reasonable and appropriate to maintain the SCAP for purposes of flowing all Solar Phase I, Solar Phase II, and Solar Phase III market credits back to customers. In this regard, we also find it appropriate to align all of the solar-related credits to flow through the SCAP. As such, the Company shall remove $6,118,411 in solar credits associated with its Solar Generation Facilities from its other operating revenues so that these solar credits are reconciled through the SCAP (Exhs. NG-RRP-2, Sch. 2, at 4 (Rev. 4); DPU 28-1). We also find it is reasonable to continue the SCAP for the purpose of recovering the costs associated with the Solar Phase III generation facility in Grafton. The Company shall submit a revised SCAP tariff consistent with the above findings as part of its compliance filing in this proceeding. In particular, Schedule 1 shall include in the list of Solar Phase I, Solar Phase II, and Solar Phase III generation facilities transferred to base distribution rates in D.P.U. 15-155, D.P.U. 18-150, and D.P.U. 23-150, respectively, for purposes of flowing all market credits back to customers.

B. Energy Efficiency Provision

1. Introduction

On December 10, 2020, the Department opened an investigation to revise its Energy Efficiency Guidelines ("Guidelines") to incorporate changes in laws, Department policies, and experience gained concerning energy efficiency. Energy Efficiency Guidelines, D.P.U. 20-150, Order Opening Investigation (2020).[260] In that Order, the Department presented several proposed revisions to the Guidelines ("Revised Guidelines"). D.P.U. 20-150, Order Opening Investigation at 2-3.[261] Of relevance here, the Department proposed to update Guidelines § 3.2.1.6 to revise the annual energy efficiency reconciliation factor ("EERF")[262] calculation to better align electric and gas energy efficiency cost recovery methods and to account for Department directives in Cost Based Rate Design, D.P.U. 12-126A through D.P.U. 12-126I at 23 (2013). D.P.U. 20-150, Order Opening Investigation at 3, 13-14 & Appendix A at 4-7.

The revised EERF calculation would allocate low-income energy efficiency program costs among the residential, residential low-income, and C&I sectors using a distribution revenue

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260 The Department first established Energy Efficiency Guidelines in 2000. Methods and Practices to Evaluate and Approve Energy Efficiency Programs, D.T.E. 98-100 (2000). In 2013, the Department adopted updated Energy Efficiency Guidelines. Updating Energy Efficiency Guidelines, D.P.U. 11-120-A (2013).

261 The Revised Guidelines were set forth in Appendix A to D.P.U. 20-150.

262 The EERF collects additional funds for approved energy efficiency programs when the cost of implementing those programs exceeds other funding sources. G.L. c. 25, § 19(a). Other funding sources are: (1) a mandatory $0.00250 per kWh system benefits charge pursuant to G.L. c. 25, § 19; (2) revenues from the forward capacity market administered by ISO-NE; (3) revenues from cap-and-trade pollution control programs (e.g., the Regional Greenhouse Gas Initiative) allocated by DOER to the energy efficiency programs; and (4) other outside funding sources. G.L. c. 25, § 19(a).

allocator and collect the resulting allocation from each rate class in the sector using a volumetric charge. D.P.U. 20-150, at 14, citing D.P.U. 12-126A through D.P.U. 12-126I at 23. This change would result in two EERFs, one for the combined residential and low-income sector, and one for the C&I sector. D.P.U. 20-150, Order Opening Investigation at 14. Low-income customers would continue to receive a discount on their total electric bill. D.P.U. 20-150, Order Opening Investigation at 14.

In its final Order adopting the Revised Guidelines, the Department determined that it would be appropriate to implement the revised EERF calculation method as part of a proceeding where a full analysis of the bill impacts could be performed. D.P.U. 20-150-A at 34-35. Accordingly, the Department directed each EDC to submit a revised EERF calculation method and tariff, consistent with the Revised Guidelines, as part of its next base distribution rate case. D.P.U. 20-150-A at 35-36.

In its initial filing, the Company submitted a revised Energy Efficiency Provision tariff, proposed M.D.P.U. No. 1523 (replacing M.D.P.U. No. 1444) with a revised EERF calculation method designed to address the Department's directives in D.P.U. 20-150-A (Exhs. NG-PP-1, at 39-40; NG-PP-8; proposed M.D.P.U. No. 1523). The Company proposes to implement the revised EERF calculation method on May 1, 2025 (i.e., the date of its next scheduled EERF change) (Exh. NG-PP-1, at 40; M.D.P.U. 1444).

The Company maintains that its proposed revised Energy Efficiency Provision tariff effectuates the Department's directives in D.P.U. 20-150-A regarding the calculation of the EERF (Company Brief at 546-547). No other party addressed this issue on brief.

2. Analysis and Findings

The Department has reviewed the Company's proposed Energy Efficiency Provision tariff and supporting documentation (Exhs. NG-PP-1, at 39-40; NG-PP-8; proposed M.D.P.U. No. 1523). The Department finds that that proposed tariff complies with the directives of D.P.U. 20-150-A at 34-36. In particular, the revised EERF calculation method appropriately allocates low-income energy efficiency program costs between a single residential and low-income combined sector and the C&I sector using a distribution revenue allocator and collects the resulting allocation from each rate class in the sector using a volumetric charge (Exhs. NG-PP-1, at 39-40; NG-PP-8; proposed M.D.P.U. No. 1523). D.P.U. 20-150-A at 34-36; D.P.U. 20-150, Order Opening Investigation at 14, citing D.P.U. 12-126A through D.P.U. 12-126I at 23. The Department affirms that this EERF calculation method is reasonable. Accordingly, with the amendment addressed below, the Department approves the Company's proposed Energy Efficiency Provision tariff, M.D.P.U. No. 1523.

Regarding the timing of the implementation of the revised EERF calculation method, the Department's Order adopting the Revised Guidelines contemplated that each company would provide a revised EERF calculation in its next base distribution rate case. D.P.U. 20-150-A at 34-35. See also D.P.U. 22-22, at 433. NSTAR Electric, Cape Light Compact JPE, and Unitil already have adopted consolidated EERFs. NSTAR Electric Company, D.P.U. 23-41 (2023); Cape Light Compact JPE, D.P.U. 23-40 (2023); Fitchburg Gas and Electric Light Company, D.P.U. 24-47-A (June 28, 2024); D.P.U. 23-80/D.P.U. 23-81, at 480-485. Accordingly, the Department directs the Company to file revised 2024 EERFs, consistent with the formula contained in proposed M.D.P.U. No. 1523, as part of the compliance filing the instant docket for effect November 1, 2024.[263] The Company shall amend proposed M.D.P.U. No. 1523 to add language clarifying that its revised EERFs will take effect on May 1st of each year "unless otherwise ordered by the Department."

The revisions to the EERF calculation method will result in an EERF reduction for non-low-income residential customers and an increase for low-income customers. In Section XVI.A.2.c. above, the Department approved a multi-tiered low-income discount for qualifying customers. Inasmuch as low-income customers will continue to receive a discount on their total electric bill equal to or higher than the current discount, the multi-tiered low-income discount will help mitigate the bill impacts to many income-eligible customers from the revised EERF calculation method when implemented on November 1, 2024.

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263 The Department approved the Company's 2024 EERFs in Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-31 (April 29, 2024). The Company shall design its revised 2024 EERFs for effect November 1, 2024 to collect the costs associated with the Company's energy efficiency program implementation in 2024 as presented in D.P.U. 24-31 (i.e., the only changes should be those needed to consolidate the low-income and residential EERFs and to apply the updated distribution revenue allocator). Since the Department approved the Company's 2024 EERFs, the Company twice has received Department approval to modify its energy efficiency budget. Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 23-154, Stamp Approval (June 24, 2024); Massachusetts Electric Company and Nantucket Electric Company, D.P.U. 24-99, Stamp Approval (August 9, 2024). To the extent the Company seeks to collect these additional costs prior to its next scheduled EERF change on May 1, 2025, it must file a separate petition at least 60 days in advance of any proposed rate change.

XVIII. OTHER ISSUES

A. Pole Attachments

1. Introduction

Pursuant to G.L. c. 166, § 25A and 220 CMR 45.00, the Department and the Department of Telecommunications and Cable ("DTC") have the joint authority, guided by a memorandum of understanding ("MOA"), to determine and enforce the reasonable rates, terms, and conditions of the use of utility-owned poles and conduits. Prior to 2007, the Department and the DTC were a single agency known as the Department of Telecommunications and Energy ("DTE"), which is the agency referenced in the statute. Because the provisions of 220 CMR 45.00 involve electric, telecommunications, and cable services, the Department and the DTC use the MOA, in part, to clarify the roles of each agency under those regulations and to resolve complaints.

The Department and DTC have different statutory responsibilities: (1) under G.L. c. 25, § 1A, the Department must prioritize the safety, security, reliability, affordability, equity, and reductions in GHG emissions of electric, gas, and water utilities service; and (2) under G.L. c. 25C, § 1, the DTC is tasked with the general supervision of telephone and telegraph companies and community antenna television systems, as well as the development of statewide policy on broadband matters with the Massachusetts Broadband Institute.[264]

[264] The Massachusetts Broadband Institute was established by the Legislature in 2008 to close gaps in broadband availability. An Act Establishing and Funding the Massachusetts Broadband Institute, St. 2008, c. 231.

In the instant case, National Grid made no proposals concerning utility poles or pole attachment rates. On brief NECTA raises several issues for the Department's consideration. Those issues are discussed below.[265]

2. Positions of the Parties

a. NECTA

i. Company Record Keeping

NECTA argues that National's Grid utility pole-related recordkeeping must be improved to fully comply with FERC's and the Department's governing standards (NECTA Brief at 2-3, citing 18 C.F.R. Part 101, General Instructions 2.A; 220 CMR 51.01; NECTA Reply Brief at 1). NECTA points to different systems the Company uses to track pole information and the nature and extent of the information tracked (or not) by these systems (NECTA Brief at 3 n.9). NECTA contends that pole heights are a key input in calculating pole attachment rates and that National Grid records those heights differently depending on the database; specifically, in ten-foot increments in the Company's continuing property records ("CPR") database and in five-foot increments in the Company's geographic information system ("GIS") database (NECTA Brief at 4). According to NECTA, to ensure pole attachment rates are compensatory and non-subsidized, National Grid should align its systems so that pole heights are recorded

265 On June 21, 2024, in conjunction with the filing of its initial brief, NECTA filed a Motion to File Documents Subsequent to Hearing ("NECTA Motion"). NECTA sought to admit to the record testimony from proceedings held before the Connecticut Public Utilities Regulatory Authority regarding utility pole-hardening programs and investment in non-pole appurtenances and other support items (NECTA Motion at 2). On June 28, 2024, the Company filed an opposition to the NECTA Motion. As set forth below, the Department does not rely on these additional documents to reach its decision. Accordingly, without comment on the merits, the NECTA Motion is denied.

accurately and precisely (NECTA Brief at 4-5). NECTA asserts that because poles are produced and purchased in five-foot increments, recording poles at five-foot increments in the CPR would better meet FERC and Department standards as actual cost invoices would match pole inventory (NECTA Brief at 5). Thus, NECTA requests that the Department direct National Grid to record actual pole heights in its CPR (NECTA Brief at 5).

NECTA also argues that more accurate, precise, and timely recordkeeping is necessary with respect to pole and non-pole items (e.g., anchors and crossarms) booked to Account 364 to ensure pole attachment rates are properly calculated and costs are appropriately allocated between third-party attachers and ratepayers (NECTA Brief at 5; NECTA Reply Brief at 1). According to NECTA, National Grid may be carrying significant amounts of non-unitized investment (i.e., investment that is not yet classified into specific retirement units) in Account 364 over several years (NECTA Brief at 6). NECTA contends that the Company's failure to classify investment into specific retirement units in a timely fashion may result in a mismatch of investment dollars and associated units, and as non-pole investments become an increasingly important component of hardening programs, is likely to result in an overstatement of the percentage of pole to non-pole investment (NECTA Brief at 6). NECTA asserts that any significant mismatch impacts the pole attachment rate and the likelihood of achieving the goal of compensatory, efficient, and nonsubsidized rates (NECTA Brief at 6). NECTA requests that the Department require National Grid to maintain a sufficient level of tracking of pole and non-pole items and require the Company to accelerate its accounting processing of non-unitized investment so that the delay in unitizing the investment is not more than one cost-reporting year (NECTA Brief at 6-7).

ii. Make-Ready Payments

NECTA argues that there is no evidence that National Grid assigns make-ready[266] payments (costs paid by third-party attachers to the Company to prepare poles for the attachers) as offsets to the same accounts where the associated pole-related costs were booked which, according to NECTA, is necessary to avoid subsidization of third-party attachers by ratepayers (NECTA Brief at 7-8, citing Exh. NECTA 2-3). NECTA asserts that the Department should ensure that National Grid books these costs appropriately (NECTA Brief at 8).

NECTA also argues that National Grid uses unit costs to prepare make-ready cost estimates, but the Company does not true-up the estimates to ensure that third-party attachers are not overpaying or underpaying for make-ready work (NECTA Brief at 8). NECTA asserts that the Company should be required to perform a true-up to ensure accurate estimates and that ratepayers are not subsidizing third-party attachers and vice versa (NECTA Brief at 8-9).

b. Company

National Grid asserts that it complies with its obligation to determine the pole attachment rate calculation on an annual basis to offset customer electric rates through pole attachment fees (Company Reply Brief at 93, citing Exh. NECTA 1-18). The Company also maintains that pole attachment rate calculations use actual GIS pole inventory at heights where the poles are installed, i.e., in five-foot increments (Company Reply Brief at 93, citing Tr. 8, at 1107).

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266 "Make-ready" generally refers to the modification or replacement of a utility pole, or of the lines or equipment on the utility pole, and site preparation to accommodate additional facilities on the pole. Accelerating Wireline Broadband Deployment by Removing Barriers to Infrastructure Investment, 33 FCC Rcd. 7705, 7706 (2018); Fiber Technologies Networks, L.L.C., D.T.E. 02-47, at 1 n.2 (2002).

Further, the Company argues that it has controls in place to ensure its records are accurate and that it performs accurate and timely pole attachment rate calculations, and there is no evidence in the record to the contrary (Company Reply Brief at 94-95, citing Exh. NECTA 2-15). Finally, the Company contends that it has provided all data that is relevant to pole attachment rate calculations to NECTA and continues to cooperate with NECTA to provide additional data upon request (Company Reply Brief at 95, citing Exh. NECTA 3-1, Att.; Tr. 8 at 1165-1166).

3. Analysis and Findings

a. Company Recordkeeping

National Grid's internal recordkeeping systems differ in the manner in which distribution wood pole heights are recorded. In 2004, consistent with a system move to PowerPlan[267] and to consolidate reporting among affiliates, National Grid began recording pole units-of-property in ten-foot increments in the Company's CPR (RR-NECTA-1; RR-NECTA-2). According to the Company, the recording approach in the CPR is consistent with how pole units-of-property have been historically recorded in financial records (Exh. NECTA 2-6; Tr. 8, at 1106-1107). The Company notes, however, that exact pole heights may be maintained in various other systems, with the most relevant being the Company's GIS, which maintains pole heights in five-foot increments and tracks pole count and location (Exhs. NECTA 1-21; NECTA 2-6; Tr. 8, at 1107-1108).

The Department has adopted the Uniform System of Accounts for Electric Companies used by FERC and prescribed at 18 C.F.R. Part 101, with several modifications.

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267 The PowerPlan system is a project and asset reporting subledger system.

220 CMR 51.01(1). Relevant to our discussion is Account 364, which is associated with poles, towers, and fixtures. While the Department recognizes the importance of accurate and consistent recordkeeping, there is no requirement in Account 364 for utility poles to be recorded in specific height increments (e.g., five-foot increments, ten-foot increments). Further, the record is unclear as to the extent to which the Company would need to modify its current CPR to record pole heights in shorter increments, the cost of doing so, and the potential impact on other recordkeeping systems. Moreover, there is no evidence presented in this proceeding that the Company's current method of recording pole heights has resulted in inaccurate or improper pole attachment rates. In particular, for purposes of calculating pole attachment rates, the Company uses the five-foot pole height increments in the GIS (Tr. 8, at 1165).

The Company routinely collaborates with NECTA and pole attachers on pole-related issues.[268] In particular, the Company has provided to NECTA and individual pole attachers, pole-related data from the Company's GIS upon request (Tr. 8, at 1107, 1165-1166). Thus, pole-height information in five-foot increments is readily available to pole attachers. Pole attachers also can challenge National Grid's pole-height data maintained in the CPR and GIS systems through an auditing process, although the Company noted that such a challenge has not been initiated in approximately eight years (Tr. 8, at 1166-1167).

In addition to investment in poles, Account 364 includes investments in non-pole items such as guys, anchors, crossarms, pole top pins, and other equipment that is attached to poles

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[268] During evidentiary hearings, it was apparent that Company representatives and NECTA's counsel have a positive working relationship. The Department appreciates both parties' efforts to work together on pole-related issues.

(Exh. NECTA 1-22). A portion of this equipment, known as appurtenances, is of little to no use or benefit to the attaching parties and, therefore, is deducted from Account 364 to determine the total net investment in poles. In 1998, the DTE established the "Massachusetts Formula," which pole attachers and pole- and conduit-owners continue to rely on in calculating pole attachment and conduit rates in the Commonwealth.[269] A-R Cable Service, et al. v. Massachusetts Electric Company, D.T.E. 98-52, at 7-8 (1998); Cablevision of Boston Company, et al. v. Boston Edison Company, D.P.U./D.T.E. 97-82, at 15-19 (1998). In adopting the Massachusetts Formula, the agency's goal was to simplify pole attachment rates as much possible by adopting standards that rely on publicly available data. D.T.E. 98-52, at 7; D.P.U./D.T.E. 97-82, at 19. In particular, the DTE found that it was reasonable to estimate or presume that 15 percent of the total net pole investment represented appurtenances that were not used or useful to the attaching companies and, therefore, would act to reduce the dollar amount of net pole investment allocated in the Massachusetts Formula. D.T.E. 98-52, at 10; D.P.U./D.T.E. 97-82, at 30. The 15-percent estimate or presumption is rebuttable when sufficient Account 364 subaccount data for net pole investment demonstrates that actual investment in appurtenances is different from 15 percent. D.T.E. 98-52, at 13.

The record shows that as of year-end 2022, the Company had over $36.6 million in non-unitized costs (Exhs. NECTA 1-18, Att. 1, at 2; NECTA 1-21).[270] Investments that are

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269 This should not be confused with the "Massachusetts formula" developed in 1919 by Massachusetts for the purpose of apportioning income tax liabilities for companies with multi-state operations. D.P.U. 08-27, at 85-86 n.47.

270 The Company states that when pole construction is complete and poles are placed in service, the related costs are transferred to Plant in Service in Account 364

non-unitized are removed from the pole attachment rate calculation (see Exh. NECTA 1-18, Att. 1, at 2). To the extent that a larger percentage of appurtenances remain non-unitized, the overall pole attachment rate will be higher than if those non-pole items were unitized and accounted for in the percentage of unitized appurtenances for purposes of determining the total net investment in poles pursuant to the Massachusetts Formula (see Exh. NECTA 1-18, Att. 1, at 2). The Company states that because the work orders related to the non-unitized costs were not yet assigned to detailed pole accounts, the breakdown of those costs into pole and non-pole items is unknown (Exhs. NECTA 1-18, Att. 1, at 2; NECTA 1-21). Nevertheless, the year-end 2022 pole investment information was used to calculate the 2024 pole attachment rates (Exhs. NECTA 1-18 & Atts.; NECTA 1-21). The record contains some information on the Company's general process for updating records related to pole activity, and while it may seem excessive for costs to remain non-unitized for two years, the specific reasons for the level of uncategorized costs in 2022 is not discernable from the record (see, e.g., Exhs. NECTA 1-23; NECTA 1-25; NECTA 2-15).

The Department recognizes the importance of accurately recording pole heights, tracking pole and non-pole items, timely unitizing investments, and appropriately allocating the percentage of pole and non-pole items so that the inputs into the Massachusetts Formula result in appropriate pole attachment rates. While the Company's pole-related tracking processes may not satisfy NECTA's level of granularity (see NECTA Brief at 3 n.9), we are not persuaded that the

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(Exh. NECTA 1-21). Before the specific retirement units are assigned, the costs are shown as "uncategorized," which appears to be synonymous with non-unitized (Exh. NECTA 1-21).

Company's recordkeeping practices are substantially delinquent, nor is there convincing evidence that current pole attachment rates are not just and reasonable (Exhs. NECTA 1-22; NECTA 1-25; NECTA 2-14; NECTA 2-15; NECTA 3-9). Based on the above considerations, the Department is not persuaded that it is necessary at this time to direct the Company to modify its CPR system to record utility poles in five-foot increments or to direct the Company to accelerate its accounting processing of non-unitized investment. The Department, however, encourages the Company and NECTA to continue to work together to ensure pole-height transparency and accurate pole-attachment rates, and for the Company to consider whether any changes to the CPR and its accounting processes for unitizing investments would facilitate these objectives.

b. Make-Ready Payments

In situations where a third-party seeks to attach to a Company utility pole and is responsible for the preparatory attachment work, the Company provides a make-ready estimate that a third-party attacher pays in advance (Tr. 8, at 1094). The make-ready payments made by third-party attachers would be included in any of the cost element descriptions that map to the CIAC expense type groupings (Exh. NECTA 2-5).[271] When a third-party attacher submits a make-ready payment, the Company books the payments into multiple accounts because they are spread between the types of costs estimated for the work being performed (Exh. NECTA 2-5). These accounts include Account 107 (CWIP); Account 108 (Cost of Removal); and any expense

[271] These groupings include electric revenue; miscellaneous electric service revenue; miscellaneous service revenues; other electric revenue - miscellaneous; other expenses – construction reimbursement; other expenses – reimbursements; and revenue from nonutility operations (Exh. NECTA 2-5).

or appropriate revenue accounts at the time they are received (Exhs. NECTA 1-15; NECTA 2-5; Tr. 8, at 1095). The make-ready costs are subsequently recorded as credits in more detailed asset accounts depending on specific types of costs (Exh. NECTA 2-5; Tr. 8, at 1095-1096). The intention of this recording process is to provide in the Company's revenue requirements a dollar-for-dollar offset to pole-related costs in the amount of the make-ready payment (see Exhs. NECTA 1-15; Tr. 8, at 1097).

NECTA argues that there is no evidence that National Grid assigns make-ready payments to the exact same accounts where the costs were booked which, according to NECTA, is necessary to avoid subsidization of third-party attachers by ratepayers (NECTA Brief at 7-8, citing Exh. NECTA 2-3). In particular, NECTA cites to Verizon's payments to National Grid for costs related to jointly owned poles as not being associated with specific work orders (NECTA Brief at 8 n.30, citing Exh. NECTA 2-3). The Company, however, presented evidence that make-ready payments are treated as revenues and credited to the same accounts, and in the same amounts, as the original pole-related costs (Exhs. NG-RRP-2, Sch. 2, at 1, 3 (Rev. 4); NECTA 1-15; NECTA 2-5; Tr. 8, at 1097). With respect to the Verizon example, the Company explained that accumulated billing credits sent to Verizon for jointly owned poles are applied to reduce the overall cost of Account 364 in National Grid's CPR (Exh. NECTA 2-3). Further, the Company stated that due to the delay between the installation of assets, the collection of costs for that work, and the periodic billing that occurs, it is not practical to apply the billing credit to the work order where the pole was installed (Exh. NECTA 2-3). We find this explanation to be reasonable. Based on the record before us, the Department is not persuaded that any directives regarding the Company's practice of assigning make-ready payments to specific accounts are necessary at this time.

NECTA also asserts that the Company should be required to perform a true-up to ensure accurate estimates and that ratepayers are not subsidizing third-party attachers and vice versa (NECTA Brief at 8-9). National Grid acknowledges that when providing make-ready estimates, the Company tries to estimate within ten percent of the actual cost (Tr. 8, at 1097, 1104-1105). The Company also acknowledges that if a make-ready estimate is too low or too high, it could lead to subsidization by either the customer or third-party attacher to meet actual costs (Tr. 8, at 1097-1099, 1105). Currently, the Company does not true-up make-ready estimates with actual costs (Tr. 8, at 1104-1105). National Grid noted that in most cases the make-ready payment is insufficient compared to what the Company pays for make-ready construction, though in some cases the Company can adjust make-ready costs (Tr. 8, at 1104-1105).

There is no requirement in G.L. c. 166, § 25A or the Department's regulations for the Company to true-up make-ready payments. The statute and regulations, however, require that pole attachment rates be just and reasonable. G.L. c. 166, § 25A; 220 CMR 45.07. Further, in considering rates, terms, and conditions applicable to attachments, the Department shall consider the interests of utility customers. G.L. c. 166, § 25A (requiring the Department to consider the interests of utility subscribers); CRC Communications LLC v. Massachusetts Electric Company and Verizon New England Inc., D.T.C. 22-4, at 46 n.14 (2022). Based on the considerations above, the Department concludes that it is reasonable and appropriate for the Company to continue to adjust make-ready payments where possible (Tr. 8, at 1104-1105). We also are persuaded that the Company, as part of its internal recordkeeping for accounting and pole rate calculation purposes, should true-up make-ready payments with final make-ready construction costs, if necessary. We conclude that these efforts will help ensure that make-ready payments accurately reflect the final related construction costs and, consistent with cost-causation principles, will help avoid any subsidization by utility customers (or third-party attachers). At this time, we will not require the Company to file any specific documentation showing make-ready payment reconciliations. The Company, however, shall maintain contemporaneous make-ready true-up records that can be readily available for review should the need arise.

B. Use of Risk Ranking for Disconnection Purposes

1. Introduction

Pursuant to the Department's regulations governing billing and termination procedures, 220 CMR 25.02(3), the Company may not terminate service until, at least 28 days after the initial bill, it has sent a second request for payment including notice that it will terminate service no sooner than 48 days from receipt of the initial bill. 220 CMR 25.02(3)(b). If the bill remains unpaid, the Company renders a final notice of termination not earlier than 45 days after receipt of the bill but at least 72 hours, and no more than 14 days, prior to the planned termination. 220 CMR 25.02(3)(c).

As part of its disconnection process, the Company relies on a third-party vendor, Experian, to calculate "risk grades" for accounts that have billed approximately 25 days prior and have not yet been paid (Exh. MEDA 3-4). This risk ranking, which is based on Experian's proprietary behavioral scoring methodology, includes factors such as number of payment agreement extensions, whether a customer owns, rents, or has unknown housing status, number of payments made on the account, and months of service (Exh. MEDA 3-4 & Att.; Tr. 3, at 423-424, 426-427). The risk ranking affects how quickly a customer enters the disconnection process (Tr. 3, at 441). Customers considered at low risk for nonpayment are provided more time to pay their bill and may be prompted with a phone call before a second request for payment (i.e., an initial disconnection notice) is sent, while customers deemed at higher risk are sent an initial disconnection notice sooner and thus may be disconnected sooner, even if both sets of customers have the same amount and age of arrears (Tr. 3, at 434-435, 443-444). In addition to the risk ranking, the Company also relies on the amount and age of arrears to determine the disconnection path for a customer (Exh. MEDA 3-4; Tr. 1, at 143, 156-157; Tr. 3, at 433). Prior to National Grid's implementation of this system in 2009-2010, every customer received a disconnection notice as soon as they "entered collections" (Tr. 3, at 437).

National Grid works with Experian about every five years to revise the scoring process but does not maintain documentation related to Experian's proprietary methodology and does not know exactly how the risk scoring is mathematically calculated (Exh. MEDA 3-4; Tr. 3, at 424, 429-430, 431). According to the Company, its termination procedures are consistent with Massachusetts regulations, and it does not use the risk-ranking process to accelerate or determine the rate at which a customer is disconnected (Exhs. MEDA 3-5; NG-CP-Rebuttal-1, at 33-34; RR-AG-17).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Company's use of risk ranking causes different customers to move through the collections and disconnection process at different speeds, with a quicker path to disconnection for those customers found to be at high risk (Attorney General

Reply Brief at 62). The Attorney General asserts that this leads to several problems (Attorney General Reply Brief at 62). First, the Attorney General contends that the risk-ranking process has a harmful cyclical effect on the Company's most financially vulnerable customers, as those who struggle to pay their bills more often and are disconnected more frequently will receive higher risk scores (Attorney General Reply Brief at 62-63). The Attorney General notes that disconnected customers may also incur costs associated with housing/shelter instability, employment difficulties, childcare, and medical consequences encountered as a result of a disconnection, which perpetuates the collection and disconnection cycle (Attorney General Reply Brief at 63). The Attorney General also maintains that a quicker disconnection timeline reduces the likelihood that the customer can apply for and obtain necessary bill assistance (Attorney General Reply Brief at 63).

Second, the Attorney General claims that certain factors assessed in Experian's customer risk-score calculation (owning/renting, number of payments made to date, and months of service) disfavor renters and has notable racial equity implications (Attorney General Reply Brief at 64). Third, the Attorney General argues that the other factors assessed in addition to the Experian risk score (such as evaluating amount owed and age of arrears) magnify equity concerns (Attorney General Reply Brief at 64-65). Overall, the Attorney General asserts that moving some customers in arrears towards disconnection faster than others is a practice that directly conflicts with the Company's commitment to structural equity, and the Attorney General recommends that the Department direct the Company to cease use of risk ranking in its disconnection process (Attorney General Reply Brief at 65).

b. MEDA

MEDA argues that the Company's use of risk ranking negatively impacts whether lower income customers can remain connected to essential utility service and discriminates against financially struggling customers (MEDA Brief at 53; MEDA Reply Brief at 24, citing Tr. 3, at 434-435). MEDA contends that the rate at which a customer moves through the disconnection process is specifically impacted by a customer's risk ranking, leading to customers' proceeding through the disconnection practice on two separate tracks: one track for those deemed low risk for non-payment, and a quicker track for those deemed higher risk (MEDA Brief at 55, 56; MEDA Reply Brief at 24). MEDA asserts that a customer who is considered a higher risk will inevitably remain stuck in that category if collection activity is applied on an accelerated basis as compared to the lower risk customers (MEDA Brief at 57; MEDA Reply Brief at 25). MEDA further asserts that if one customer receives a disconnection notice because it was given less time to pay because of a high-risk score, that customer's score is negatively impacted going forward and its arrearage will grow, while the low-risk customer is given more time to make a payment and avoid the disconnection process altogether (MEDA Brief at 57; MEDA Reply Brief at 25-26, citing Exh. MEDA-1.0, at 50 (Rev.)). Thus, according to MEDA, two customers with the same outstanding balances of the same duration in terms of days past due are treated differently in the disconnection queue (MEDA Brief at 57, citing Tr. 3, at 443-444; MEDA Reply Brief at 25).

In particular, MEDA contends that the factors used in the risk-ranking algorithm (which include owning/renting, number of payments made life to date, and months of service) negatively impact renters because renters tend to move more frequently than homeowners, and low-income customers are more likely to be renters (MEDA Brief at 53, 55-56, citing

Exh. MEDA-1.0, at 49 (Rev.)). MEDA further contends that if a customer's designation as a renter or owner cannot be determined, its score is negatively impacted (MEDA Brief at 56, citing Tr. 3, at 425-426).

In addition, MEDA argues that the Company does not maintain documentation related to Experian's self-designated "proprietary" behavioral scoring methodology, it is unclear how the factors are weighted, and the Company cannot fully explain how Experian assesses a customer's scoring for their likelihood of payment and how the score affects how fast a customer moves through the disconnection cycle (MEDA Brief at 54-55, 56, citing Exh. MEDA-1.0, at 47 (Rev.); Tr. 3, at 427-428, 430). MEDA also argues that the Company has never reviewed the proprietary mathematical calculations that produce a risk score (MEDA Brief at 56, citing Tr. 3, at 430).

MEDA points out that Massachusetts case law authorizes different treatment of different classes of customers and differing rate treatment within a customer class for a specific, non-discriminatory purpose, such as discounted low-income rates or reduced rates for seniors (MEDA Brief at 58-59, citing American Hoechest, 379 Mass. 408, 411-412; Boston Edison, 375 Mass. 1). Nevertheless, MEDA asserts that there is no case precedent that authorizes disparate application of the disconnection process for customers within the same rate class, and the Department's regulations regarding service disconnection do not authorize different timelines for sending disconnection notices based on a customer's risk ranking, particularly when that action has such dire impacts on a customer's ability to remain connected to essential utility service (MEDA Brief at 59). Thus, MEDA urges the Department to order the Company to halt any use of risk ranking in its timing of the disconnection of its customers, or at least to provide those ranked as high risk the same amount of extended time as those ranked as low risk (MEDA Brief at 59; MEDA Reply Brief at 26).[272]

c. Company

The Company maintains that it follows all regulations in 220 CMR 25.00 prior to terminating a residential customer, including all relevant notifications (Company Reply Brief at 72). The Company argues that the Attorney General is incorrect in asserting that renters are disfavored in the risk-ranking process (Company Reply Brief at 69, citing Attorney General Reply Brief at 64). The Company asserts that the same number of points are assigned to renters and owners currently, although there may have been different points assigned years ago (Company Reply Brief at 69-70, citing Tr. 3, at 424-425). The Company acknowledges that customers with an unknown housing status receive zero points but maintains that those customers represent less than one percent of all customers (Company Reply Brief at 70, citing Tr. 3, at 424-425). The Company further asserts that it could explore removing the rent/own metric altogether or assign the same number of points to rent, own, and unknown status when it is next able to adjust the metrics (Company Reply Brief at 70, 74, citing Tr. 3, at 424-425).

The Company also argues that the Attorney General is incorrect in alleging that the Company is moving certain customers towards disconnection on a faster timetable (Company Reply Brief at 70, citing Attorney General Reply Brief at 64-65). According to the Company, slow and fast are relative terms and do not provide an appropriate point of comparison because various circumstances could lead to faster or slower customer disconnections (Company Reply

[272] DOER supports MEDA's recommendation to halt the Company's use of risk ranking (DOER Reply Brief at 7).

Brief at 70, citing Tr. 3, at 447-449). The Company contends that it does not accelerate any high-risk customers towards disconnection and only decelerates low-risk customers (which may include low-income customers) who may have an opportunity to self-cure (Company Reply Brief at 70-71, citing Tr. 1, at 142-44, 154; Tr. 3, at 434-435, 443-444). The Company asserts that the goal is to use the most effective mechanism for a particular customer and to reduce overall costs while improving arrearage levels, but it uses the same disconnection process for all customers regardless of risk (Company Reply Brief at 71, citing Tr. 1, at 144-145, 151-153, 156; Tr. 3, at 439-444). The Company maintains that customers on the low-income discount rate (Rate R-2) will inherently move towards collections slower than customers on Rate R-1 with similar usage because the discount rate means that arrears will not accrue as quickly to a level triggering disconnection (Company Reply Brief at 71).

National Grid also objects to the Attorney General's claim that the Company's risk-ranking practice represents a structural inequality (Company Reply Brief at 72, citing Attorney General Reply Brief at 64). The Company contends that it began using the process in 2008 when it implemented enhanced collection efforts to avoid further increases in bad debt write-offs in light of the economic recession and rising unemployment, and that the risk-ranking process has resulted in collections mitigation with a demonstrably positive cost-benefit outcome (Company Reply Brief at 72-73, citing RR-AG-6 & Att. 1). The Company argues that it if were to terminate the risk-ranking process, it would not only lose the annual benefits of the program but would then need to reevaluate and overhaul its current collections practices, which would result in further expense and time to replace it and would increase bad debt write-offs (Company Reply Brief at 73). Moreover, the Company asserts that the Attorney General has not provided evidence or even a suggestion of an appropriate replacement collections program (Company Reply Brief at 73).

The Company further describes the risk-ranking process as a fair mechanism using neutral metrics to review all customers in the same manner without prejudice (Company Reply Brief at 74, citing Exh. MEDA 3-4, Att.; Tr. 3, at 422-427). National Grid contends that the process is fair because Experian uses only the customer's payment behavior from the Company to determine likelihood of payment and does not use any Experian data (Company Reply Brief at 74, citing Tr. 3, at 426-430). National Grid asserts that it is the most fair and effective way to prioritize collection activity, as the Company cannot send all customers to field disconnection at the same time (Company Reply Brief at 74). The Company also asserts that any time a customer in arrears pays without the need for some type of collection activity, it is a purely positive outcome for other ratepayers (Company Reply Brief at 74). Moreover, the Company contends that in addition to the customer payment behavior risk score, the collection treatment path is also based on arrears balance and age of arrears, which are also neutral and unbiased factors that the Attorney General and MEDA have not addressed (Company Reply Brief at 75, citing Tr. 1, at 146, 156-157; Tr. 3, at 433).

The Company argues that any management of the collections and disconnections process must involve a determination of how to prioritize accounts for disconnection, and that any alternative method will still prioritize one account over another in some manner (Company Reply Brief at 75). The Company maintains that if it were to provide the same amount of time to financially struggling customers before entering the disconnecting cycle as provided to low-risk customers, as MEDA suggests, this would mean a "first in arrears, first to disconnect" strategy, which could result in a customer that falls behind by a few days for the first time being swiftly disconnected (Company Reply Brief at 75, citing MEDA Reply Brief at 26). National Grid contends that any prioritization mechanism other than the customer's behavior with the Company would be inherently biased in some other way, as well as less effective and more costly (Company Reply Brief at 76). Further, the Company asserts that if the Department finds the Attorney General's and MEDA's claims of inequality compelling, it should address the risk-ranking issue with a more thorough investigation and stakeholder input in the energy burden docket, D.P.U. 24-15, and not in this base distribution rate proceeding (Company Brief at 465; Company Reply Brief at 73-74, 76).

3. Analysis and Findings

Within a substantial range, business decisions are matters for a company's determination. Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 375 Mass. 571, 578 (1978). The Department does not act as an appellate board of directors and, barring extraordinary circumstances, will not interpose itself in a utility's daily management. National Grid/KeySpan Merger, D.T.E. 07-30, at 22 (2010); see also D.P.U. 85-266-A/85-271-A at 11 (Department will not make management decisions on behalf of utility's managers). Notwithstanding the importance accorded to management discretion, the Department has a long-standing policy of reviewing management decisions and efficiency as matters of legitimate public interest. Gas Shortage Investigation, D.P.U. 555, at 9 (1982); see also G.L. c. 164, § 76.

In the instant proceeding, the Department finds the Company's use of risk ranking to be reasonable under the circumstances, not inconsistent with Department policy, and an appropriate use of management discretion. It would not be practical or efficient for National Grid to move all customers into the disconnection process at the same time, so some form of prioritization is necessary. Further, depending on the factors used, an alternative prioritization method could be inherently biased in some other way. Requiring the Company to develop an alternative prioritization method could be less effective and is likely to add additional costs to ratepayers. Further, the Company's use of risk ranking does not violate the Department's regulations governing termination of service, 220 CMR 25.02(3) (Exh. MEDA 3-1). There is insufficient information in the record to determine whether the risk-ranking factors have racial equity implications.

Therefore, the Department declines at this time to direct the Company to stop using risk ranking to determine when a customer enters the disconnection process. Nonetheless, the record demonstrates that there may be some inequity in the owner/renter metric as owners and renters receive the same positive score in that factor but those with unknown housing status receive a negative score (Tr. 3, at 425-426). To ensure greater fairness in the process, we direct the Company to remove the rent/own metric or assign the same number of points to the elements in that factor when the Company is next able to adjust the metrics (Tr. 3, at 424-425). The Department may further investigate risk-ranking factors in D.P.U. 24-15.

C. Disconnection Notices

1. Introduction

Pursuant to Department regulations, the Company issues two termination notices after sending a bill and prior to disconnecting a customer: a second request for payment, and a final notice of termination. 220 CMR 25.02(3)(b), (c). These two notices contain the following sentences in English plus six other languages: "This is an important notice. Please have it translated" (Exh. MEDA-CP 1-1, Atts. 1, 2). The remainder of the notices, which are otherwise printed in English, includes information about the discount rate, payment plans, disconnection protections for certain vulnerable populations, and AMP (Exh. MEDA-CP 1-1 & Atts. 1, 2).

2. Positions of the Parties

a. MEDA

MEDA argues that the Company's termination notices fail to provide important information about the availability of LIHEAP assistance and guidance on how to find the nearest CAP agencies to apply for LIHEAP (MEDA Brief at 60; MEDA Reply Brief at 26-27). MEDA asserts that providing information about additional LIHEAP assistance available to those financially eligible and where it can be accessed may make the difference between uninterrupted access to essential utility service versus disconnection and avoid all the negative health and safety consequences that accompany loss of electric service (MEDA Brief at 60). To minimize disconnections, MEDA recommends that the notices provide information about LIHEAP and include a phone number and website link, for those with internet access, which will assist financially struggling customers in locating LIHEAP assistance (MEDA Brief at 60-61, citing Exh. MEDA-1.0, at 64-65 (Rev.); MEDA Reply Brief at 27).

In addition, MEDA argues that the Company should provide these notices in both English and in any language spoken at home by at least ten percent of zip code residents who are at least five years of age, rather than simply requiring customers to find someone to translate the information provided therein (MEDA Brief at 60, 61, citing Exh. MEDA-1.0, at 63-64 (Rev.); MEDA Reply Brief at 27). MEDA asserts that it is not enough to direct a customer in six different languages to have the information translated, and the Company's failure to translate these materials negatively impacts customers' ability to seek assistance and hold off potential disconnections (MEDA Brief at 60, 63). Moreover, MEDA argues that there is evidence that the Company can do more regarding translation, as the Company's website currently allows users to translate English into a host of languages (MEDA Brief at 62-63, citing Exh. MEDA-Surrebuttal-1, at 26-27.). MEDA recommends that the Department order National Grid to have the translated materials reviewed by CBOs serving particular populations, with the CBOs compensated for any work that is asked of them to help ensure quality translations, and that the Company should consult with the Massachusetts Office for Refugees and Immigrants, and perhaps also with the Trial Court Office of Language Access, to ensure best practices in translation services (MEDA Brief at 62, citing Exh. MEDA-1.0, at 65 (Rev.)).

MEDA notes that the Company's response to these recommendations was to assert that including LIHEAP information directly in the notice may result in confusion and potential for disconnection, that customers are directed to call or visit the National Grid website (www.ngrid.com/billhelp) for more information, and that changes to notices take time and cannot be updated regularly to coincide with LIHEAP seasonality (MEDA Brief at 62, citing Exh. NG-CP-Rebuttal-1, at 38). MEDA contends that these arguments ring hollow as some amount of time for change is to be expected but it is not clear whether that time is one week or longer (MEDA Brief at 62). MEDA also asserts that it is not enough to refer customers to National Grid's website for more information where financially struggling customers may also be struggling with access to the internet (MEDA Brief at 63). According to MEDA, it is not unreasonable to ask the Company to provide a paper notice with the necessary information to access needed energy assistance, including LIHEAP and the relevant dates of the LIHEAP program year (MEDA Brief at 63, citing Exh. MEDA-Surrebuttal-1.0, at 27). Thus, MEDA argues, the Company should provide financially struggling customers the courtesy of translated notices before disconnecting their service, and there is nothing in the Company's rebuttal that suggests these proposed translations and additional information requirements would be burdensome or expensive (MEDA Brief at 63, citing Exh. MEDA-Surrebuttal-1.0, at 27).[273]

b. Company

The Company states that it appreciates MEDA's suggestions and will review them for potential implementation, while noting several caveats (Company Reply Brief at 77). First, the Company expresses concern that including information on LIHEAP year-round on its notices may be misleading to customers during the summer months, when LIHEAP applications are not being processed (Company Reply Brief at 77). Second, the Company states that it is not aware of a centralized phone number or website for CAP agencies where a customer could go to find out more information and individual CAP agencies frequently change web locations, so it would not be practical to include such information on the Company's standard notices (Company Reply Brief at 77). Third, regarding translations, the Company states that it will investigate appropriate avenues to make translations of its notices available, such as by referring customers to a website with all available translations, but that attempting to send multiple translations with every paper notice may be costly and not appropriate for any given customer (Company Reply Brief at 77). Further, the Company contends that a base distribution rate case is not the appropriate forum to

[273] DOER also supports MEDA's recommendation to revise the second request for payment and final notice of termination to include LIHEAP availability, assistance from CAP agencies, and increased translation (DOER Reply Brief at 7).

change the language of its collections notices and should be addressed in another proceeding (Company Reply Brief at 77).

3. Analysis and Findings

Pursuant to 220 CMR 25.02(11), the Department has the authority to approve the language and form of all written notices required by the regulations regarding billing and termination procedures, 220 CMR 25.00, and may require that such notices be written in languages other than English. MEDA's recommendations are certainly worthy of consideration, and we note that the Company is willing to review them for potential implementation. We find that there is insufficient reason to omit LIHEAP information from notices where information on how to access payment plans and AMPs is already included and where any confusion can be avoided by including the relevant dates of the LIHEAP program year (Exh. MEDA-Surrebuttal-1.0, at 27). For example, the Company could include the phone number and website for the EOHLC, which maintains a website with necessary LIHEAP information including ways to look up the relevant CAP agencies. We also direct the Company to investigate ways to make translations of its notices readily accessible to its customers in compliance with the Department's Language Access Plan[274] and requirements in D.P.U. 21-50. Thus, we direct the Company to explore MEDA's recommendations and make these improvements to its notices within the next twelve months.

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274 The Department's Language Access Plan is located at the following website, https://mass.gov/doc/september-17-2024-dpu-language-access-plan-english/download. See the Massachusetts Office of Environmental Justice and Equity "languages spoken" map, which can be found at the following website: https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts.

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	601,829,166	(8,948,865)	16,678,171	609,558,472
Depreciation & Amortization	205,913,633	(754,840)	(15,957,874)	189,200,919
Taxes Other Than Income Taxes	99,416,056	5,219,075	(4,901)	104,630,230
Interest on Customer Deposits	101,129	357,487	0	458,616
Income Taxes	54,541,199	(1,120,096)	(17,240,582)	36,180,522
Return on Rate Base	244,922,872	(1,602,448)	(21,647,180)	221,673,243
Additional Uncollectibles (Revenue Deficiency)	1,872,447	(184,851)	(552,531)	1,135,065
Total Cost of Service	1,208,596,501	(7,034,538)	(38,724,898)	1,162,837,067
OPERATING REVENUES				
Base Distribution Revenues	1,034,432,466	0	0	1,034,432,466
Other Operating Revenues	42,931,182	5,920,948	0	48,852,130
Total Operating Revenues	1,077,363,648	5,920,948	0	1,083,284,596
Total Revenue Deficiency	**131,232,853**	**(12,955,486)**	**(38,724,898)**	**79,552,470**

Numbers may not add due to rounding, and 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
O&M Per Books	1,522,150,964	0	0	1,522,150,964
Normalizing Adjustments	(982,875,267)	(6,401,836)	0	(989,277,103)
Test Year O&M Expense	539,275,697	(6,401,836)	0	532,873,861
ADJUSTMENTS TO O&M EXPENSE:				
Labor	22,785,224	205,092	0	22,990,316
Health Care	(1,138,533)	803,823	0	(334,710)
Group Life Insurance	225,320	1,858	0	227,178
Thrift Plan	1,233,186	10,129	0	1,243,315
FAS 112 / ASC 712	0	0	0	0
Service Company Rents	(4,393,955)	4,229,135	(1,070,934)	(1,235,754)
Joint Facilities	0	0	0	0
Uninsured Claims	0	0	0	0
Insurance Premium	(655,983)	698,140	0	42,157
Regulatory Assessment Fees	(426,855)	1,138,424	0	711,569
Uncollectible Accounts	0	0	0	0
Postage	276,815	448,495	0	725,310
Third Party Rents	(10,600,567)	(242,050)	0	(10,842,617)
Purchased Power-Borderline Sale	0	461,792	0	461,792
Miscellaneous Operating and Maintenance Expenses	(506,981)	0	(1,222,723)	(1,729,704)
Transmission IFA Billing to NEP	(452,411)	(1,003,940)	0	(1,456,351)
Wheeling	0	0	0	0
Storm Fund	36,917,790	(4,497,035)	0	32,420,755
Major Storm Deductible Adjustment	2,600,000	(350,000)	0	2,250,000
Paperless Bill Credit	754,852	771	0	755,623
PBOP	0	0	181,200	181,200
Pension	0	0	12,383,600	12,383,600
Hardship Protected	(2,929,824)	0	0	(2,929,824)
Rate Case Expenses	104,725	27,993	(10,334)	122,384
Vegetation Management	7,906,044	(3,339,501)	0	4,566,543
Enhanced Vegetaion Management Pilot	0	0	7,031,709	7,031,709
Customer Account Management	1,981,315	(1,350,927)	(630,388)	0
Settlement Payment	0	0	(359,927)	(359,927)
Dues and Memberships	0	0	(3,514)	(3,514)
O&M Inflation Adjustment	8,552,818	204,671	379,482	9,136,971
Environmental Response Fund Inflation Adjustment	320,489	6,101	0	326,590
Sum of O&M Expense Adjustments	62,553,469	(2,547,029)	16,678,171	76,684,611
Total O&M Expense	**601,829,166**	**(8,948,865)**	**16,678,171**	**609,558,472**

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

C. Schedule 2A – Inflation Table

Normalized Test Year O&M Expense	527,642,521
Less Company Adjustments:	
Labor	172,886,510
Healthcare	22,052,291
Group Life & Other Insurance	1,709,390
Thrift Plan	9,355,270
FAS 112 / ASC 712	28,594
Service Company Rents	54,885,007
Insurance Premium	5,851,151
Regulatory Assessment Fees	8,515,034
Uncollectible Accounts	30,488,125
Postage	5,592,213
Third Party Rents	16,248,812
Purchased Power Borderline Sale	3,247,149
Transmission IFA Billing to NEP	(21,629,780)
Storm Fund	16,000,000
Major Storm Deductible	13,950,000
Paperless Bill Credit	2,286,411
Hardship Protected	10,284,545
Rate Case Expenses	558,146
Vegetation Management	39,558,637
Total O&M Adjustments	391,867,505
Residual O&M Expense subject to Inflation per Company	135,775,016
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year	6.45%
Inflation Allowance per Company as proposed	8,757,489
Department Adjustments	
Residual O&M Expense subject to inflation per Department	135,775,016
Dues and Memberships	(3,514)
Settlement Payment	(359,927)
EVM Pilot	7,031,709
Appreciate Program employee recognition expenses	(1,222,723)
Residual O&M Expense subject to inflation per Department	141,220,561
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year	6.47%
Inflation Allowance per Department	9,136,970
Environmental Response Fund	5,231,340
Projected Environmental Response Fund Rate	6.24%
Inflation Allowance for Environmental Response	326,590
Department Reduction to Cost of Service	379,482

D. Schedule 3 – Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation & Amortization	198,181,087	(754,840)	(15,957,874)	181,468,373
Farm Discount	408,190	0	0	408,190
Gain on Sale of Property	(421,408)	0	0	(421,408)
Amortization of Accumulated Exogenous Impact for Property Tax	7,745,764	0	0	7,745,764
Total Depreciation and Amortization Expense	205,913,633	(754,840)	(15,957,874)	189,200,919

Numbers may not add due to rounding, and 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	6,003,802,141	(1,034,110)	0	6,002,768,031
LESS:				
Reserve for Depreciation and Amort.	(2,064,537,367)	(11,925,468)	0	(2,076,462,835)
Net Utility Plant in Service	3,939,264,774	(12,959,578)	0	3,926,305,196
ADDITIONS TO PLANT:				
Cash Working Capital	67,355,764	(1,857,149)	817,688	66,316,302
Other Materials and Supplies	34,038,774	0	0	34,038,774
Prepayments	0	0	0	0
Total Additions to Plant	101,394,538	(1,857,149)	817,688	100,355,076
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	(604,059,360)	40,142,859	(83,867,636)	(647,784,137)
Estimated Excess Deferred Taxes	(266,685,310)	(5,357,446)	49,606,411	(222,436,345)
Customer Construction Advances	(15,972,246)	0	0	(15,972,246)
Customer Deposits	(13,905,579)	0	0	(13,905,579)
Total Deductions from Plant	(900,622,495)	34,785,413	(34,261,225)	(900,098,307)
RATE BASE	3,140,036,817	19,968,686	(33,443,537)	3,126,561,965
COST OF CAPITAL	7.80%	-0.10%	-0.71%	7.09%
RETURN ON RATE BASE	**244,922,872**	**(1,602,448)**	**(21,647,180)**	**221,673,243**

Numbers may not add due to rounding, and 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	$2,200,000,000	46.47%	4.70%	2.18%
Preferred Stock	$2,259,000	0.05%	4.44%	0.00%
Common Equity	$2,531,834,000	53.48%	10.50%	5.62%
Total Capital	$4,734,093,000	100.00%		7.80%
Weighted Cost of				
Debt				2.18%
Preferred				0.00%
Equity				5.62%
Cost of Capital				7.80%

ADJUSTED PER COMPANY

	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$2,200,000,000	47.12%	4.56%	2.15%
Preferred Stock	$2,259,000	0.05%	4.44%	0.00%
Common Equity	$2,466,834,000	52.83%	10.50%	5.55%
Total Capital	$4,669,093,000	100.00%		7.70%
Weighted Cost of				
Debt				2.15%
Preferred				0.00%
Equity				5.55%
Cost of Capital				7.70%

PER ORDER

	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$2,200,000,000	47.12%	4.56%	2.15%
Preferred Stock	$2,259,000	0.05%	4.44%	0.00%
Common Equity	$2,466,834,000	52.83%	9.35%	4.94%
Total Capital	$4,669,093,000	100.00%		7.09%
Weighted Cost of				
Debt				2.15%
Preferred				0.00%
Equity				4.94%
Cost of Capital				7.09%

Numbers may not add due to rounding, and 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
CTC Expense	14,985,199	140,476	0	15,125,675
Total O&M	601,829,166	(8,948,865)	16,678,171	609,558,472
Transmission	615,630,956	0	0	615,630,956
Uncollectible Accounts	30,488,125	0	0	30,488,125
Paperless Bill Credit	3,041,264	771	0	3,042,035
Hardship Protected	0	7,354,721	0	7,354,721
Taxes Other than Income	147,579,773	5,234,423	(4,901)	152,809,295
	1,346,495,705	(10,929,458)	16,673,270	1,352,239,517
Cash Working Capital Factor	5.00%	16.99%	4.90%	4.90%
Cash Working Capital Allowance	67,355,764	(1,857,149)	817,688	66,316,302

Numbers may not add due to rounding, and 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
Municipal Tax	81,809,885	0	0	81,809,885
Payroll Tax	15,812,849	0	0	15,812,849
Other Taxes	(977,360)	0	0	(977,360)
	96,645,374	0	0	96,645,374
ADJUSTMENTS TO TAXES OTHER THAN INCOME:				
Normalizing adjustments:				
Municipal Tax	(1,598,323)	6,733	0	(1,591,590)
Payroll Tax	(1,404,787)	(3,177)	0	(1,407,964)
Other Taxes	1,238,734	0	0	1,238,734
Known & measurable adjustments:				
Municipal Tax	3,263,170	5,288,284	(4,901)	8,546,553
Payroll Tax	1,255,421	(73,157)	0	1,182,264
Other Taxes	16,467	392	0	16,859
Total Adjustments	2,770,682	5,219,075	(4,901)	7,984,856
Totals				
Municipal Tax	83,474,732	5,295,017	(4,901)	88,764,848
Payroll Tax	15,663,483	(76,334)	0	15,587,149
Other Taxes	277,841	392	0	278,233
Taxes Other Than Income	99,416,056	5,219,075	(4,901)	104,630,230

Numbers may not add due to rounding, and 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	3,140,036,817	19,968,686	(33,443,537)	3,126,561,965
Return on Rate Base	244,922,872	(1,602,448)	(21,647,180)	221,673,243
Interest Expense	68,452,803	(512,684)	(719,036)	67,221,082
Amortization of Net Excess Deferred Tax	0	0	8,773,726	8,773,726
Total Flow-through Federal & State Income Tax Expense	8,571,080	516,362	(5,372,692)	3,714,750
Income Tax Impact of Flowthrough Items	0	0	0	0
Amortization of Net Unfunded Deferred Tax Liability	0	0	0	0
Total Deductions	77,023,883	3,678	2,681,998	79,709,558
Taxable Income Base	167,898,989	(1,606,126)	(24,329,178)	141,963,685
Gross Up Factor	1.3759	1.3759	1.3759	1.3759
Taxable Income	231,011,270	(2,209,859)	(33,474,379)	195,327,032
State Franchise Tax at 8%	18,480,902	(176,789)	(2,677,950)	15,626,163
Federal Taxable Income	212,530,369	(2,033,071)	(30,796,429)	179,700,870
Federal Income Tax at 21%	44,631,377	(426,945)	(6,467,250)	37,737,183
Amortization of Net Excess Deferred Tax	0	0	(12,071,720)	(12,071,720)
Total Flow-through Federal & State income tax expense	(8,571,080)	(516,362)	3,976,338	(5,111,104)
Income Tax Impact of Flowthrough Items	0	0	0	0
Amortization of Net Unfunded Deferred Tax Liability	0	0	0	0
Total Income Taxes	**54,541,199**	**(1,120,096)**	**(17,240,582)**	**36,180,522**

Numbers may not add due to rounding, and 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 REVENUES PER BOOKS	945,811,002	0	0	945,811,002
Known & Measurable Adjustments-Decoupling Accrual	88,621,464	0	0	88,621,464
Adjusted Total Firm Revenues	1,034,432,466	0	0	1,034,432,466
Other Revenues	44,086,184	5,956,670	0	50,042,854
Known & Measurable Adjustments-Other Misc. Revenue	(1,155,002)	(35,722)	0	(1,190,724)
Adjusted Total Firm Revenues	42,931,182	5,920,948	0	48,852,130
Operating Revenues	989,897,186	5,956,670	0	995,853,856
Known & Measurable Adjustments	87,466,462	(35,722)	0	87,430,740
Adjusted Total Operating Revenues	1,077,363,648	5,920,948	0	1,083,284,596

Numbers may not add due to rounding, and minor discrepancies between these numbers and those in the text are due to rounding.

K. Schedule 10 – Illustrative Allocation to Rate Classes

			TOTAL	R-1 and R-2 Residential and Residential Low-Income	G-1 General Small C&I	G-2 General Medium C&I (Demand)	G-3 General Large C&I (TOU)	SL All Street Lighting
Per Order COSS Revenue Requirement								
Current Base Distribution Revenue	(A)	*using current rates and test year billing determinants Source: Exhibit NG-PP-2 (Rev. 4), at 1, Line 1*	$1,034,432,466	$604,321,620	$129,838,787	$115,692,253	$168,955,481	$15,624,325
Current Other Revenue	(A')	*Source: Exhibit NG-PP-2 (Rev. 4), at 1, Line 2*	$48,852,131	$28,959,227	$5,339,303	$5,158,988	$9,152,709	$241,904
Per Order COSS Revenue Requirement	(B)	*Source: see Exhibit NG-PP-2 (Rev. 4)*	$1,162,837,074	$695,096,435	$136,549,940	$122,739,384	$187,429,721	$21,021,594
Per Order COSS Target Revenue	(B')	**= B - A'**	$1,113,984,943	$666,137,208	$131,210,637	$117,580,396	$178,277,012	$20,779,690
Per Order Base Distribution Revenues (Deficiency) at EROR	(C)	**= B' - A**	$79,552,477	$61,815,589	$1,371,850	$1,888,143	$9,321,532	$5,155,364
Percent Increase at EROR	(D)	**= C / A**	**7.69%**	10.23%	1.06%	1.63%	5.52%	33.00%
Total Revenue Based on Current Rates	(E)	*Source: Exhibit NG-PP-4 (Rev. 4), at 2, Line 31*	$5,706,603,187	$2,794,956,201	$612,648,449	$707,955,937	$1,557,493,547	$33,549,053
Per Order Increase / (Decrease) in Total Delivery Service Revenues at EROR	(F)	**= C**	$79,552,477	$61,815,589	$1,371,850	$1,888,143	$9,321,532	$5,155,364
Percent Increase / (Decrease) at Per Order Revenue Increase / (Decrease)	(G)	**= F / A**	**7.69%**	10.23%	1.06%	1.63%	5.52%	33.00%
10% TOTAL DELIVERY SERVICE REVENUE CAP								
10% of Current Total Delivery	(H)	= **E** x 10%	$570,660,319	$279,495,620	$61,264,845	$70,795,594	$155,749,355	$3,354,905
Meet 10% Cap?	(I)	if **F > H**, then NO, otherwise YES		YES	YES	YES	YES	NO
Increase / (Decrease) in Excess of Cap	(J)	if **I** = NO, then **F - H**, otherwise 0	$1,800,459	-	-	-	-	$1,800,459
Allocator for Increase Over Cap	(K)	if **I** = NO, then 0, otherwise **B'**	$1,093,205,254	$666,137,208	$131,210,637	$117,580,396	$178,277,012	-
Allocation of Cap	(L)	if **I** = NO, then 0, otherwise [total **J** * **K** / total **O**]	$1,800,459	$1,097,097	$216,098	$193,650	$293,614	-
Reallocated Per Order Distribution Revenue Increase / (Decrease) in Total Revenues	(M)	= **F - J + L**	$79,552,477	$62,912,686	$1,587,948	$2,081,793	$9,615,146	$3,354,905
10% Check	(N)	if **M > H**, then NO, otherwise YES		YES	YES	YES	YES	YES
200% BASE DISTRIBUTION REVENUE CAP ITERATION 1								
Per Order Base Distribution Revenue Increase	(O)	= total **C** / total **A**	**7.69%**					
200% of Base Distribution Revenue Cap	(P)	= Total **O** * 2.00 * **A**	$159,104,955	$92,950,064	$19,970,365	$17,794,502	$25,986,862	$2,403,161
Meet 200% Cap?	(Q)	if M **>** **P**, then NO, otherwise YES		YES	YES	YES	YES	NO
200% BASE DISTRIBUTION REVENUE CAP ITERATION 2								
Increase / (Decrease) in Excess of Cap	(R)	if **Q** = NO, then **M - P**, otherwise 0	$951,744	$0	$0	$0	$0	$951,744
Allocator for Increase Over Cap	(S)	if **Q** = NO, then 0, otherwise **B'**	$1,093,205,254	$666,137,208	$131,210,637	$117,580,396	$178,277,012	$0
Allocation of Cap	(T)	if **Q** = NO, then 0, otherwise [total **R** * **S** / total **S**]	$951,744	$579,939	$114,232	$102,365	$155,208	$0
Reallocated Per Order Distribution Revenue Increase / (Decrease) in Base Distribution Revenues	(U)	= **M - R + T**	$79,552,477	$ 63,492,625	$ 1,702,179	$ 2,184,158	$ 9,770,354	$ 2,403,161
200% check	(V)	if **U > P**, then NO, otherwise YES		YES	YES	YES	YES	YES
PER ORDER BASE DISTRIBUTION REVENUE REQUIREMENT	(W)	= **A + U**	$1,113,984,943	667,814,245	131,540,967	117,876,411	178,725,834	18,027,486
PER ORDER REVENUE INCREASE	(X)	= **W - A**	$79,552,477	63,492,625	1,702,179	2,184,158	9,770,354	2,403,161

FOR ILLUSTRATIVE PURPOSES ONLY

XX. ORDER

Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the tariffs M.D.P.U. Nos. 1511 through 1520 filed by Massachusetts Electric Company on November 16, 2023, to become effective December 1, 2023, are DISALLOWED; and it is

FURTHER ORDERED: That the tariffs M.D.P.U. Nos. 666 through 675 filed by Nantucket Electric Company on November 16, 2023, to become effective December 1, 2023, are DISALLOWED; and it is

FURTHER ORDERED: That the tariffs M.D.P.U. Nos. 1521 through 1537 filed by Massachusetts Electric Company and Nantucket Electric Company on November 16, 2023, to become effective December 1, 2023, are DISALLOWED; and it is

FURTHER ORDERED: That Massachusetts Electric Company and Nantucket 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 Massachusetts Electric Company and Nantucket 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 Massachusetts Electric Company and Nantucket Electric Company shall comply with all other directives contained in this Order; and it is

FURTHER ORDERED: That the new rates for electricity for effect October 1, 2024, and to be billed and implemented beginning November 1, 2024, shall not be billed earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order, unless otherwise ordered by the Department.

By Order of the Department,

James M. Van Nostrand, Chair

Cecile M. Fraser

Cecile M. Fraser, Commissioner

Staci Rubin, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.