The Commonwealth of Massachusetts

DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 18-150 September 30, 2019

Petition of Massachusetts Electric Company and Nantucket Electric Company, each doing business as National Grid, pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of General Increases in Base Distribution Rates for Electric Service.

APPEARANCES:

Cheryl M. Kimball, Esq.
Daniel P. Venora, Esq.
Jameson Calitri, Esq.
Ashley S. Wagner, Esq.
Keegan Werlin LLP
99 High Street, Suite 2900
Boston, Massachusetts 02110

-and-

Alexandra E. Blackmore, Esq.
Andrea G. Keefe, Esq.
National Grid
40 Sylvan Road
Waltham, Massachusetts 02451
FOR: MASSACHUSETTS ELECTRIC COMPANY
AND NANTUCKET ELECTRIC COMPANY
Petitioner

Maura Healey, Attorney General
Commonwealth of Massachusetts
By: Joseph W. Rogers
Elizabeth A. Anderson
Joseph F. Dorfler
Alexander M. Early
Ashley Gagnon
John J. Geary
Matthew E. Saunders
Assistant Attorneys General
Office of Ratepayer Advocacy
One Ashburton Place
Boston, Massachusetts 02108
Intervenor

Department of Energy Resources
Commonwealth of Massachusetts
By: Colin P. Carroll, Esq.
Ben Dobbs, Esq.
Rachael Graham Evans, Esq.
Robert H. Hoaglund II, Esq.
100 Cambridge Street, Suite 1020
Boston, Massachusetts 02114
Intervenor

Amy E. Boyd, Esq.
Acadia Center
51 Milk Street, Suite 501
Boston MA 02109
FOR: ACADIA CENTER
Intervenor

Jen Bosco, Esq.
Charles Harak, Esq.
National Consumer Law Center
7 Winthrop Square, 4th Floor
Boston, Massachusetts 02110
FOR: THE MASSACHUSETTS ENERGY DIRECTORS ASSOCIATION
Intervenor

John W. Giorgio, Esq.
Matthew G. Feher, Esq.
KP Law, P.C.
101 Arch Street, Floor 12
Boston MA 02110
FOR: TOWN OF NANTUCKET
Intervenor

Paul G. Afonso, Esq.
Jesse S. Reyes, Esq.
Brown Rudnick LLP
One Financial Center
Boston MA 02111
FOR: CHARGEPOINT, INC.
Limited Intervenor

David Ismay, Esq.
Conservation Law Foundation
62 Summer Street
Boston MA 02110
FOR: CONSERVATION LAW FOUNDATION
Limited Intervenor

Kevin Conroy, Esq.
Kelly Caiazzo, Esq.
Foley Hoag LLP
155 Seaport Boulevard
Boston MA 02110-2600
FOR: CUMBERLAND FARMS, INC., GLOBAL PARTNERS LP, THE NEW ENGLAND CONVENIENCE STORE AND ENERGY MARKETERS ASSOCIATION, THE SOCIETY OF INDEPENDENT GASOLINE MARKETERS OF AMERICA, AND THE NATIONAL ASSOCIATION OF CONVENIENCE STORES
Limited Intervenors

Elisa J. Grammer, Esq.
Law Offices of Elisa J. Grammer
48 Coffin Street
West Newbury MA 01985
FOR: GREEN ENERGY CONSUMERS ALLIANCE, THE SIERRA CLUB, THE NATURAL RESOURCES DEFENSE COUNCIL, AND THE UNION OF CONCERNED SCIENTISTS
Limited Intervenors

Joshua Berman, Esq.
The Sierra Club
50 F Street NW, 8th Floor
Washington DC 20001
FOR: THE SIERRA CLUB
Limited Intervenor

David C. Fixler, Esq.
John A. DeTore, Esq.
Greenberg Traurig, LLP
One International Place, Suite 2000
Boston MA 02110
FOR: NORTHEAST CLEAN ENERGY COUNCIL
Limited Intervenor

Bernice I. Corman, Esq.
EKM Law, PLLC
800 Connecticut Avenue, NW, Suite 410
Washington DC 20006

-and-

Kevin Auerbacher
Sr. Counsel, Legal
Tesla, Inc.
1000 K Street, NW, Suite 101
Washington DC 20001
FOR: TESLA, INC.
Limited Intervenor

Carol J. Holahan, Esq.
Foley Hoag LLP
155 Seaport Boulevard
Boston MA 02210-2600
FOR: AMERICAN PETROLEUM INSTITUTION
Limited Participant

Robert A. Rio, Esq.
Associated Industries of Massachusetts
One Beach Street, 16th Floor
Boston MA 02109
FOR: ASSOCIATED INDUSTRIES OF MASSACHUSETTS
Limited Participant

Jinjue Allen, General Counsel
Enel X North America, Inc.
One Marina Park Drive, Suite 400
Boston MA 02210
FOR: ENEL X NORTH AMERICA, INC. AND
ELECTRIC MOTOR WERKS, INC.
Limited Participant

Kevin F. Penders, Esq.
John M. Sullivan, Esq.
Preti, Flaherty, Beliveau & Pachios, LLP
60 State Street, Suite 1101
Boston MA 02109
FOR: ZECO SYSTEMS, INC. D/B/A GREENLOTS
Limited Participant

Laura S. Olton, Esq.
LSO Energy Advisors, LLC
38 Thackeray Road
Wellesley MA 02481
FOR: POWEROPTIONS, INC.
Limited Participant

TABLE OF CONTENTS

I. INTRODUCTION

On November 15, 2018, 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 of Public Utilities ("Department") pursuant to G.L. c. 164, § 94, and 220 CMR 5.00 for an increase in its electric base distribution rates of $132,236,908.[1] The Company's proposal also included a decrease of $61,924,044 in revenues recovered in charges outside of base distribution rates, resulting in an overall net increase of $70,312,864. Based on changes made during the proceeding, National Grid now proposes a general increase in base distribution rates of $115,953,077, a decrease of $60,774,105 in revenues recovered in charges outside of base distribution rates, resulting in an overall net increase of $55,178,971 (Exh. NG-RRP-2 (Rev. 4), Sch. 1).[2] The Company also proposes to (1) replace its capital investment recovery mechanism ("CIRM") with a performance-based ratemaking ("PBR") mechanism that would allow National Grid to adjust its base distribution rates on an annual basis through the application of a revenue-cap formula and (2) implement metrics to evaluate National Grid's performance. National Grid based its proposed base distribution rate increase on a test year of January 1, 2017 through December 31, 2017 (Exh. NG-MLR-1, at 5-6). National Grid was last granted an increase

---

1 MECo filed for approval of tariffs M.D.P.U. Nos. 1373 through 1383, Nantucket Electric filed for approval of tariffs M.D.P.U. Nos. 610 through 620, and together MECo and Nantucket Electric filed for approval of tariffs M.D.P.U. Nos. 1384 through 1401.

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

in electric base distribution rates in 2016. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 15-155 (2016). The Department docketed the instant petition as D.P.U. 18-150, and suspended the effective date of the tariffs until October 1, 2019, for further investigation.[3]

National Grid provides retail electric distribution service to customers in 172 cities and towns in Massachusetts in a service territory covering 3,870 square miles (Exhs. NG-MLR-1, at 18; AG 13-25). MECo serves 1,311,975 million customers and Nantucket Electric serves 13,275 customers (Exh. AG 13-25). MECo and Nantucket Electric operate as 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-MLR-1, at 18; AG 1-98, Att. at 1).[4] National Grid USA also owns National Grid USA Service Company ("NGSC"), which provides management, administrative, accounting, legal, engineering, information systems, and other services to National Grid USA subsidiaries, including MECo and Nantucket Electric (Exhs. NG-RRP-1, at 1; AG 1-26, Att. 2, at 41-42; AG 1-98, Att. at 1). In addition, National Grid USA owns

3 While the Company requests that the new base distribution rates be effective October 1, 2019, it seeks to implement the rates effective November 1, 2019 (Exh. NG-HSG-1, at 45). The Company would recover the incremental base distribution revenue accrued for the first month of the rate year through the revenue decoupling adjustment factors (Exh. NG-HSG-1, at 48).

4 National Grid plc owns and operates electric transmission and gas transmission and distribution networks in the United Kingdom (Exh. NG-MLR-1, at 18).

affiliated electric and gas distribution companies operating in Rhode Island and New York (Exh. NG-MLR-1, at 18).

On November 20, 2018, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a notice of intervention pursuant to G.L. c. 12, § 11E.[5] On January 3, 2019, the Department granted the petitions to intervene as full parties to: (1) the Massachusetts Department of Energy Resources ("DOER"); (2) Acadia Center ("Acadia Center"); (3) the Massachusetts Energy Directors Association ("MEDA")[6]; and (4) the Town of Nantucket ("Nantucket") (Tr. at 8-9). On January 3, 2019, the Department granted limited intervention status[7] to: (1) ChargePoint, Inc. ("ChargePoint"); (2) Cumberland Farms, Inc., Global Partners LP, the New England Convenience Store and Energy Marketers Association, the Society of Independent Gasoline Marketers of America, and the National Association of Convenience Stores ("FSCS Coalition"); (3) Green Energy Consumers

---

5 On December 31, 2018, the Department approved the Attorney General's retention of experts and consultants, filed pursuant to G.L. c. 12, § 11E(b), to assist her in representing consumer interests in this case at a cost not to exceed $550,000. D.P.U. 18-150, Order on Attorney General's Notice of Retention of Experts and Consultants (December 31, 2018). The costs incurred by the Attorney General in this proceeding are reimbursed by National Grid and the Company then passes these costs on to ratepayers. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39, at 301-303 (2009).

6 Initially, the Low-Income Weatherization and Fuel Assistance Program Network and the Massachusetts Energy Directors Association submitted a joint petition to intervene. On March 15, 2019, the Low-Income Weatherization and Fuel Assistance Program Network filed a notice of withdrawal.

7 Limited intervention allows entities to participate in a proceeding on specific topics delineated in their petitions to intervenor. D.P.U. 18-150, Hearing Officer Ruling on Petitions for Intervention at 1 (January 8, 2019).

Alliance, the Sierra Club, the Natural Resources Defense Council, and the Union of Concerned Scientists ("Clean Energy Parties"); and (4) Northeast Clean Energy Council, Inc. ("NECEC").[8] On January 8, 2019, the Department granted limited intervention status to: (1) Conservation Law Foundation ("CLF"); and (2) Tesla, Inc. ("Tesla"). On January 3, 2019, the Department granted limited participant status to: (1) American Petroleum Institution ("API"); (2) Associated Industries of Massachusetts ("AIM"); (3) Enel X North America, Inc. ("Enel X") and Electric Motor Werks, Inc. ("eMotor Werks"); (4) Zeco Systems, Inc., d/b/a Greenlots ("Greenlots"); and (5) PowerOptions, Inc. ("PowerOptions").

Pursuant to notice duly issued, the Department held five public hearings in the Company's service territory: (1) Lawrence on March 26, 2019; (2) Brockton on March 28, 2019; (3) Nantucket on April 2, 2019; (4) Worcester on April 4, 2019; and (5) Great Barrington on April 9, 2019.[9] The Department held 15 days of evidentiary hearings from Monday, April 29, 2019 through Thursday, May 23, 2019.

In support of its filing, National Grid sponsored the testimony of 22 witnesses: (1) Marcy L. Reed, president of Massachusetts jurisdiction and executive vice president of U.S. policy and social impact at NGSC; (2) Ian M. Springsteel, director of U.S. retail

---

[8] At the procedural conference on January 3, 2019, NECEC opposed the granting of limited intervention and sought full intervention (Tr. at 13-14). On January 8, 2018, the Hearing Officer issued a written ruling affirming the decision to granting limited intervention status. D.P.U. 18-150, Hearing Officer Ruling on Petitions for Intervention at 5 (January 8, 2019). NECEC did not appeal the Hearing Officer's ruling.

[9] The Department received numerous oral and written comments during the public comment period.

regulatory strategy at NGSC; (3) Carlos A. Nouel, vice president, new energy solutions at NGSC; (4) Alan T. Labarre, director of distribution planning and asset management for New England at NGSC; (5) David E. Tufts, director of revenue requirements, New England, at NGSC; (6) Mark E. Meitzen, vice president at Christensen Associates; (7) Lawrence R. Kaufmann, president of Kaufmann Consulting and senior advisor to Pacific Economics Group Research LLC and to Navigant Consulting; (8) Amy S. Tabor, lead analyst of New England revenue requirements in the regulation and pricing department at NGSC; (9) Patricia C. Easterly, director, New England performance and planning at NGSC; (10) Robert B. Hevert, partner at ScottMadden, Inc.; (11) Maureen P. Heaphy, vice president of U.S. compensation, benefits, and pensions at NGSC; (12) Stephen R. Olive, senior vice president and U.S. chief information officer at NGSC; (13) Daniel D. DeMauro, director of U.S. information technology ("IT") regulatory compliance at NGSC: (14) Mukund Ravipaty, director, global head security services, design, and architecture at NGSC: (15) Kimbugwe A. Kateregga, vice president of Foster Associates Consultants, LLC; (16) Howard S. Gorman, president of HSG Group, Inc.; (17) Rishi Sondhi, manager for the emerging products team at NGSC; (18) Fouad E. Dagher, director of customer innovation and development organization of National Grid USA; (19) Arthur W. Hamlin, manager, economic development at NGSC; (20) Aleta M. Fazzone, director of community and customer management for the Central and Western Massachusetts regions at NGSC; (21) Bertram H. Stewart, III, manager vegetation strategy at NGSC; and (22) Ryan A. Moe, lead specialist, vegetation strategy at NGSC.[10] In

---

[10] During evidentiary hearings, National Grid made the following witnesses, who

addition, Ned W. Allis, vice president, Gannett Fleming Valuation and Rate Consultants, LLC, submitted rebuttal testimony on behalf of National Grid (Exh. NG-NWA-Rebuttal-1).

The Attorney General sponsored the testimony of seven witnesses: (1) Gregory L. Booth, president of PowerServices, Inc.; (2) David J. Effron, consultant; (3) David J. Garrett, managing member of Resolve Utility Consulting, PLLC; (4) Mark Newton Lowry, president, Pacific Economics Group Research LLC; (5) J. Randall Woolridge, professor of finance at Pennsylvania State University; (6) Scott J. Rubin, consultant; (7) Edward A. Burgess, director at Strategen Consulting. DOER sponsored the testimony of: (1) Marc D. Montalvo, president of Daymark Energy Advisors; and (2) Philip DiDomenico, managing consultant at Daymark Energy Advisors. MEDA sponsored the testimony of: (1) Darlene Gallant, community services director, Lynn Economic Opportunity, Inc.; and (2) John Howat, senior policy analyst at the National Consumer Law Center. ChargePoint sponsored the testimony of: (1) Peter John Clarke, consultant; and (2) Kevin George Miller, director of Public Policy at ChargePoint. The Clean Energy Parties sponsored the testimony of Samantha Houston, analyst at the Union of Concerned Scientists. The FSCS Coalition sponsored the testimony of: (1) David Harrison, Jr., managing director at National Economic Research Associates, Inc.; and (2) Jeff D. Makholm, managing director at National Economic Research Associates, Inc. NECEC sponsored the testimony of Nathan

---

sponsored responses to information requests but had not submitted written testimony, available for cross examination: (1) Michael T. Nappi; (2) Kevin Kelly; (3) Tracy Desroches; (4) Damaris Dominguez; (5) Kimberly Frodelius; and (6) Paula A. Roseen (Tr. 3, at 414; Tr. 5, at 594, 675; Tr. 6, at 818; Tr. 7, at 896; Tr. 10, at 1345).

Phelps, regulatory director for Vote Solar. Tesla sponsored the testimony of Katherine Bell, senior policy advisor at Tesla.

On June 14, 2019, the Attorney General, DOER, Acadia Center, API, ChargePoint, the Clean Energy Parties, CLF, eMotor Werks,[11] the FSCS Coalition, MEDA, NECEC, PowerOptions, and Tesla submitted initial briefs. On June 28, 2019, National Grid submitted its initial brief. On July 16, 2019, the Attorney General, API, ChargePoint, the Clean Energy Parties, CLF, DOER, the FSCS Coalition, Greenlots, MEDA, NECEC, and Tesla submitted reply briefs. On July 24, 2019, National Grid submitted its reply brief. The evidentiary record consists of approximately 2,059 exhibits and responses to 90 record requests.

II. PERFORMANCE-BASED RATEMAKING PROPOSAL

A. Introduction

National Grid's proposed PBR Plan encompasses three components: (1) a PBR mechanism to adjust rates annually and provide revenue support for operations and capital investment (discussed in this section); (2) performance incentive mechanism ("PIM") and scorecard metrics; and (3) a climate mitigation and adaptation plan (Exh. NG-PBRP-1, at 9). National Grid proposed a plan that transitions from the CIRM to a PBR mechanism that would adjust base distribution rates annually in accordance with a revenue cap formula (Exh. NG-MLR-1, at 10). The Company stated that this transition to a PBR mechanism is

---

11 Although Enel X and eMotor Werks jointly submitted a petition for limited participation, which was granted, only eMotor Werks submitted an initial brief.

designed to provide more flexibility in relation to operations and maintenance ("O&M") and capital cost planning that is necessary to address changes in the operating environment (Exh. NG-MLR-1, at 11).

B. PBR Mechanism Proposal

1. Introduction

National Grid's proposed PBR uses a revenue cap formula to adjust base distribution rates annually through an adjustment to the Company's revenue decoupling mechanism (Exh. NG-PBRP-1, at 42). National Grid states that it designed the proposed PBR to work in tandem with its proposed revenue decoupling mechanism (Exh. NG-MLR-1, at 10). Based on its revenue capped PBR proposal, the Company would absorb the costs associated with additional customer growth, which, according to the Company, can be interpreted as an implicit stretch factor equal to the rate of customer growth (Exh. NG-MEM-1, at 26). The PBR would adjust the base revenue requirement approved in this proceeding, which serves as the target revenue for the revenue decoupling mechanism, according to the following formula:

$PBR\% = (GDPPI_{T-1} - X - CD) + (Z_T / \text{Base Revenue}_{T-1})$, where

$PBR_{\%}$ is the percentage change to be applied to the Prior Year PBR Revenue;

$GDPPI_{T-1}$ is a price inflation index;[12]

X is a productivity offset;

12 GDPPI (also GDP-PI) refers to the gross domestic product price index, which measures changes in the prices of goods and services produced in the United States, including those exported to other countries. https://www.bea.gov/data/prices-inflation/gdp-price-index

CD is a consumer dividend;

Z is an adjustment for exogenous costs (positive or negative); and

Base Revenue is the base distribution revenue requirement.

(Exh. NG-HSG-12, Proposed M.D.P.U. No. 1400, §§ 1.02; 1.03 (Bates Stamp 285-288)).

In addition, National Grid proposed an earnings sharing mechanism that would provide a credit to customers if earnings exceed the return on equity ("ROE") approved in this proceeding by more than 200 basis points (Exhs. NG-PBRP-1, at 14-15, 46). Each element of the Company's proposed revenue cap formula and PBR mechanism is described in detail below.

2. Formula Elements

a. PBR Term

National Grid proposed a pre-defined term of five years for the PBR Plan (Exhs. NG-PBRP-1, at 9; NG-LRK-1, at 8, 56). The Company states that this five-year term is long enough to realize efficiencies and to make progress on its clean energy goals (Exh. NG-MLR-1, at 11; Tr. 8, at 1045-1046). In conjunction with the PBR term, National Grid proposed a stay-out provision whereby the Company may not file a base distribution rate case during the PBR term (Exh. NG-PBRP-1, at 47). The five-year PBR term would commence on October 1, 2019 and expire on September 30, 2024 (Exh. NG-PBRP-1, at 47). Within the five-year term, there would be four annual PBR mechanism adjustments taking effect October 1, 2020, October 1, 2021, October 1, 2022, and October 1, 2023 (Exh. NG-PBRP-1, at 47). In accordance with the proposed stay-out provision of the PBR term, the Company would be eligible to file rate schedules to put new base distribution rates into effect no earlier than October 1, 2024 (Exh. NG-PBRP-1, at 47).

b. X Factor

National Grid proposes a productivity offset ("X factor")[13] to be calculated as:

$X(I_E) = [(\%\Delta TFP^R_I - \%\Delta TFP_E) + (\%\Delta W_E - \%\Delta W_I)]$, where

$X(I_E)$ is a productivity factor used when the I factor is a measure of economy wide output inflation or GDP-PI

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

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

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

$\%\Delta W_I$ is the percentage change in electric distribution industry input price growth.

(Exh. NG-MEM-1, at 18, 19, 20, 24, 25, 26).

When a PBR mechanism utilizes an inflation factor that is a measure of economy-wide inflation, the X factor 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 (Exhs. NG-MEM-1, at 21; NG-PBRP-1, at 44). To determine the proposed X factor, National Grid conducted a productivity study of nationwide electric distribution TFP and

---

13 The X factor, also referred to as a productivity factor by the parties, consists of a productivity differential, as measured by the difference of industry productivity growth and economy wide productivity growth, and an input price differential (Exh. NG-MEM-1, at 44).

input price growth over the period 2002 through 2016 (Exh. NG-MEM-1, at 29). National Grid used two different samples for its productivity study: (1) a sample of 66 electric distribution companies intended to represent the overall nationwide electric distribution industry; and (2) a sample of 18 electric distribution companies intended to represent the distribution industry in the Northeast U.S. (Exh. NG-MEM-1, at 33). For economy-wide TFP and input price growth, the Company used official U.S. government sources (Exh. NG-MEM-1, at 33).[14]

TFP is defined as the ratio of total output to total input (Exh. ES-MEM-1, at 13). Total output consists of all the services produced by the relevant unit of production (e.g., a firm or an industry) (Exh. NG-MEM-1, at 13). Total input includes all resources used by the unit of production in providing those services (Exh. NG-MEM-1, at 14). National Grid used number of customers as the sole productivity study output measure (Exh. NG-MEM-1, at 50). For the input measure, National Grid constructed a quantity index of total input for each firm and each year based on labor, materials, customer accounts, sales expenses, plant-apportioned administrative and general expenses, and capital quantity indices (Exh. NG-MEM-1, at 51-55).

14 The sources used by the Company were: (1) Federal Energy Regulatory Commission Form 1; (2) U.S. Bureau of Labor Statistics, Employment Cost Index; (3) U.S. Bureau of Labor Statistics, Consumer Price Index for all Urban Consumers; (4) U.S. Bureau of Economic Analysis Gross Domestic Product Price Index; and (5) Federal Reserve Board of St. Louis, Federal Reserve Economic Data (Exh. NG-MEM-1, at 49, 50, 51, 52, 54, 59, 63, 66).

The Company utilized a capital cost specification method referred to as the one hoss shay method (Exh. NG-MEM-1, at 55). The basic assumption of this method is that an asset provides a constant level of services over the lifetime of the asset (Exh. NG-MEM-1, at 55-56). The one hoss shay method also requires an average service life[15] of all assets in order to estimate the quantity of capital retirements (Exh. NG-MEM-1, at 56).[16]

The results of the Company's study indicated that, for the period 2002-2016, the average growth in productivity for the national electric distribution company industry sample was equal to -0.13 percent, while the economy-wide productivity growth was equal to 0.82 percent, which generated a productivity differential of -0.95 percent for the study period (-0.13 percent less 0.82 percent = -0.95 percent) (Exh. NG-MEM-1, at 44).[17] For the same period, the average input price growth for the national electric distribution company industry sample was equal to 3.50 percent, while the economy-wide input price growth was equal to 2.73 percent, which generated an input price differential of -0.77 percent (2.73 percent less 3.50 percent = -0.77 percent) (Exh. NG-MEM-1, at 44). The sum of the national

---

15 The average service life represents the average age of asset retirements (Exh. AG 15-4).

16 In contrast, in the Attorney General's proposed TFP studies, she deployed the geometric decay and Kahn methods for capital cost specification methods (Exh. AG-MNL-2, at 2). In regard to geometric decay, the flow of services from investments in a given year declines at a constant rate over time (Exh. AG-MNL-2, at 13). The Kahn method decomposes capital cost into a price and quantity index using a simplified version of cost of service accounting (Exh. AG-MNL-2, at 15, 39).

17 Minor discrepancies in any of the amounts appearing in this section are due to rounding.

productivity differential and the national input price differential generated a -1.72 percent X factor (-0.95 percent plus -0.77 percent) (Exh. NG-MEM-1, at 44). When the Company conducted the TFP study using its regional electric distribution company industry sample, the average growth in productivity was -0.69 percent, which generated a productivity differential of -1.51 percent (Exh. NG-MEM-1, at 46). The regional sample also produced an industry input price growth average of 3.48 percent, which generated an input price differential of -0.75 percent (Exh. NG-MEM-1, at 46). The sum of the regional productivity differential and the regional input price differential generated a -2.27 percent X factor (Exh. NG-MEM-1, at 46).

The Company also produced X factors that omitted any plant-apportioned administrative and general expenses from both its regional and national samples (Exh. NG-MEM-1, at 42, 43, 45).[18] The results of these computations generated a -2.22 percent X factor for the national sample and a -2.41 percent X factor for the regional sample (Exh. NG-MEM-1, at 43, 45). The Company used an allocation formula to determine an appropriate amount of administration and general expense to attribute to the distribution function for electric distribution companies in the national and regional samples (Exh. NG-MEM-1, at 54).

With regards to the proposed PBR mechanism, the Company proposed that the X factor of -1.72 percent be incorporated, which observes the productivity average of the

---

18 Administrative and general expenses are composed of joint and common costs that span across a utility's distribution, transmission, and production functions (Exh. NG-MEM-1, at 49-50, 52-53).

national sample and includes plant-apportioned administrative and general expenses (Exh. NG-MEM-1, at 48). The Company stated that this X factor is the most appropriate because it was developed using economic criteria as well as traditional ratemaking approaches (Exh. NG-MEM-1, at 31, 48).

c. Consumer Dividend

National Grid proposed to implement a consumer dividend component as part of its PBR mechanism, which reflects an expectation that productivity gains will be realized during the PBR Plan with the consumer dividend designed to share those benefits with customers (Exhs. NG-PBRP-1, at 14; NG-LRK-1, at 6, 36). The Company proposed a consumer dividend of 0.40 percent when inflation exceeds two percent (Exhs. NG-PBRP-1, at 44; NG-LRK-1, at 36). The value of 0.40 percent for the consumer dividend was the result of a cost benchmarking study that compared National Grid's cost performance to its peers (Exhs. NG-LRK-1, at 37-45; NG-LRK-3, at 16-18).

d. Exogenous Cost Factor

The Company proposed to include an exogenous cost provision ("Z factor), which it defines as positive or negative changes to its costs that are beyond National Grid's control and are not reflected in the GDP-PI (Exhs. NG-PBRP-1, at 45; NG-MEM-1, at 11 n.12; NG-LRK-1, at 7). The Company further defined the criteria for any costs that would be eligible for recovery through the Z factor as being beyond the Company's control and due to a change in accounting requirements or regulatory, judicial, or legislative acts that uniquely affect the electric distribution industry (Exhs. NG-PBRP-1, at 45; NG-LRK-1, at 7). In addition, the exogenous cost would be required to meet a threshold of $3.0 million, which was determined by multiplying the Company's total operating revenues for calendar year 2017 of $2,268,023,815 by 0.001253 and then rounding upwards (Exhs. NG-PBRP-1, at 46; NG-LRK-1, at 7).[19] In addition to the proposed definition for exogenous costs, the Company proposed two additional items that could be eligible for recovery through the Z factor: (1) the recovery of storms costs for those events that cause the incremental costs to exceed $30.0 million; and (2) inclusion of the Patient Protection and Affordable Care Act[20] excise tax on high-cost employer medical plans (Exh. NG-PBRP-1, at 45).

e. Earnings Sharing Mechanism

As part of the PBR, the Company proposed to adopt an earnings sharing mechanism with a deadband of 200 basis points (Exhs. NG-PBRP-1, at 46; NG-MEM-1, at 7). The proposed earnings sharing mechanism would trigger a sharing of earnings with customers on a 50/50 basis when the actual distribution ROE exceeds 200 basis points above the ROE authorized by the Department (Exh. NG-PBRP-1, at 46-47).[21] When the actual ROE exceeds

---

19 The Company states the Department has previously approved a factor of 0.001253 for use in deriving the threshold for exogenous cost recovery (Exh. DPU-NG 13-5, citing Boston Gas Company, D.T.E. 03-40, at 491 (2003); The Berkshire Gas Company, D.T.E. 01-56, at 22-26 (2001); Eastern Enterprises/Colonial Gas Company, D.P.U. 98-128, at 53-54 (1999).

20 Pub. L. No. 111-148, 124 Stat. 119 (March 23, 2010).

21 The Company proposed that the distribution ROE be calculated using distribution earnings available for common equity and the capital structure approved by the Department in this proceeding (Exh. NG-HSG-12, Proposed M.D.P.U. No. 1400, § 1.04 (Bates Stamp 288)). The Company proposed that the calculation exclude incentive payments such as energy efficiency incentives, performance incentives

300 basis points above the authorized ROE, National Grid will share all earnings above 300 basis points 90 percent with customers and 10 percent with the Company (Exh. NG-PBRP-1, at 47).

3. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General argues that the Department should reject the proposed PBR mechanism. The Attorney General claims that: (1) the PBR term of five years is not long enough to achieve the efficiency promised; (2) the Company has not demonstrated that the PBR Plan will achieve any specific, measurable results, and not focus excessively on cost recovery; and (3) the Company's proposed X factor, consumer dividend component, and earnings sharing mechanism are all flawed and will impose unnecessary rate increases and, therefore, will not result in just and reasonable rates (Attorney General Brief at 137, 140-141; Attorney General Reply Brief at 3). While the Attorney General makes specific arguments as to why the PBR proposal should be rejected, she also offers modifications that she contends should be incorporated into the PBR Plan, if it is approved by the Department (Attorney General Brief at 138, 143-163; Attorney General Reply Brief at 3).

---

associated with PIMs, and long-term contract remuneration, as well as any service-quality penalties and any amounts recognized in the reporting period resulting from regulatory or court settlements related to prior periods (Exh. NG-HSG-12, Proposed M.D.P.U. No. 1400, § 1.04 (Bates Stamp 288)).

ii. PBR Term

The Attorney General argues that the Department has found that a five-year PBR term is not long enough to achieve the efficiencies and benefits that a PBR plan is expected to provide (Attorney General Brief at 137 n.65, citing Boston Gas Company, D.T.E. 03-40, at 495 (2003)). The Attorney General also argues that the Department has been more favorable to ten-year PBR plans since they provide more time for efficiency planning and can provide stronger incentives to companies (Attorney General Brief at 137 n.65, citing Bay State Gas Company, D.T.E. 05-27, at 399 (2005)).

iii. X Factor

(A) Introduction

The Attorney General claims that the Company's TFP parameters are biased to generate an X factor that benefits the Company (Attorney General Reply Brief at 42-43). Specifically, the Attorney General raises concerns with three aspects of the Company's TFP study: (1) the sample time period; (2) the sample size of electric distribution companies; and (3) the capital cost specification method (Attorney General Brief at 143-157).

(B) TFP Sample Time Period

The Company's TFP study utilized a 15-year time period from 2002 through 2016, which the Attorney General asserts is too short and should be extended further back to include more years of data, which she contends are readily available (Attorney General Brief at 143 & n.73, citing Exhs. NG-MEM-1, at 33; AG-MNL at 6; Tr. 8, at 1207-1208; Tr. 12, at 1541). The Attorney General also argues that the time period chosen by the Company is characterized by unusually rapid growth in the capital price index from 2005 to 2009, which she asserts is not likely to repeat itself during the PBR term (Attorney General Brief at 143-145, citing Exhs. AG-MNL at 8-9; AG-MNL-2, at 26; AG 15-14; Tr. 12, at 1649). The Attorney General asserts that the Company focuses primarily on the productivity differential and does not address the input price differential in its support for a 15-year time period (Attorney General Brief at 145-146, citing Exh. NG-MEM-Rebuttal-1, at 55-56; Tr. 8, at 1208-1211). Further, the Attorney General argues that the 15-year time period is inappropriate when measuring the productivity differential, given that the output measure in this proposal is the number of customers served with plant-apportioned administrative and general expenses included (Attorney General Brief at 145-146, citing Exh. NG-MEM-1, at 49-50). The Attorney General contends that the Company bases its support for measuring the productivity differential with a 15-year sample on a PBR proceeding where the output was more volatile and administrative and general expenses were excluded (Attorney General Brief at 145, citing Exh. NG-MEM-Rebuttal-1, at 55-56). The Attorney General asserts that, in contrast, she utilized a sample of data from 1996 to 2016, provided by the Company, which generated an input price differential of -0.21 percent, which the Attorney General argues is more reasonable and unbiased (Attorney General Brief at 146, citing Exh. AG-MNL-Surrebuttal at 22). While arguing for a longer period, the Attorney General defends her witness's past use of shorter periods, claiming that in one instance, a different capital cost methodology circumvented the need for a longer period (Attorney General Reply Brief at 44-45, citing Exh. NG-4, at 41). The Attorney General also contends that her witness has used a 21-year time period (Attorney General Reply Brief at 44-45, citing Tr. 12, at 1658).

(C) TFP Sample Size

National Grid's proposed X factor relies on a TFP study that utilized a nationwide sample of 66 electric distribution companies, which the Attorney General contends is too small (Attorney General Brief at 147, citing Exh. NG-MEM-1, at 33). The Attorney General asserts that the Company's argument for the sample size relies on the Department approval in NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 17-05 (2017), where a sample of 67 electric distribution companies was accepted (Attorney General Brief at 148, citing Exh. NG-MEM-Rebuttal-1, at 28). The Attorney General maintains that the Department precedent that the Company refers to was based on a sample size that represented 75 percent of electric distribution customers nationwide as opposed to the Company's sample size, which represents 71 percent of electric distribution customers nationwide (Attorney General Brief at 147, citing Exh. NG-MEM-Rebuttal-1, at 28). The Attorney General asserts that her TFP study examined a nationwide sample of 80 electric distribution companies, which represents 78 percent of electric distribution customers nationwide (Attorney General Brief at 147, citing RR-DPU-31). In addition, the Attorney General contends that it is inappropriate to compute a weighted average of the electric distribution companies since the goal of the TFP study is to measure the potential for realizing incremental scale economies of companies (Attorney General Brief at 147-148, citing Exh. AG-MNL-Surrebuttal at 19). Accordingly, the Attorney General asserts that it is appropriate to use a simple average of the sample electric distribution companies in her TFP study (Attorney General Brief at 147-148). The Attorney General also contends that the effect of the different weighting approaches was never examined by any party to determine the isolated effect that it has on the X factor (Attorney General Reply Brief at 55). Therefore, she asserts that there is no evidence to support the Company's argument that weighting could impact the results of the TFP (Attorney General Reply Brief at 55, citing Exh. AG-MNL-Surrebuttal at 19; Tr. 8, at 1216). The Attorney General also argues that the Company's method of weighting companies within the sample by customers gives a skewed result to larger companies (Attorney General Reply Brief at 55-56). The Attorney General claims that the size-weighting method leads to a drastic difference in results between the Company's nationwide and regional samples (Attorney General Reply Brief at 56, citing RR-DPU-31, Att.). The Attorney General contests the Company's argument that a simple average gives oversized accounting of smaller companies, which do not realize the same economies of scale or customer growth rates as larger companies (Attorney General Reply Brief at 56, citing Company Brief at 98). The Attorney General asserts that smaller companies have realized scaled economies, but also slow customer growth rate diminishes the opportunity for achieving scale economies (Attorney General Reply Brief at 56, citing Exh. AG-MNL-2, at 8-9; Tr. 12, at 1564). Further, the Attorney General contends that the Company did not provide any evidence that smaller utilities have significantly different rates of customer growth (Attorney General Reply Brief at 56).

(D) Capital Cost Specification Method

The Attorney General argues that the Company's capital cost specification method is flawed (Attorney General Brief at 148-157). The Company utilized the one hoss shay method, which the Attorney General asserts does not take into effect depreciation or the cost benefits of using older assets (Attorney General Brief at 150, citing Exh. AG-MNL-Surrebuttal at 9; Tr. 12, at 1601). Specifically, the Attorney General maintains that the one hoss shay method, as presented by the Company, does not feature a decline in the capital quantity or the capital service price, which would be expected due to rising maintenance expenses and decreasing reliability as assets age (Attorney General Reply Brief at 46-47). The Attorney General also contends that prices in many used asset decay markets are inconsistent with the one hoss shay method (Attorney General Reply Brief at 47, citing Exh. AG-MNL-2, at 17-18). In addition, the Attorney General claims that the Company's defense of the one hoss shay depreciation pattern focuses on similar assets, rather than a mixed group of assets (Attorney General Brief at 155, citing Exh. NG-NWA-Rebuttal-1, at 14-17; Attorney General Reply Brief at 47 & n.27, citing Exh. AG-MNL-2, at 17-18). Further, the Attorney General asserts that the one hoss shay method relies on selecting an accurate average service life assumption (Attorney General Brief at 150). The Attorney General argues that the 33-year average service life assumption used in the Company's one hoss shay method ignores that average service lives have risen in a nonlinear manner from 1994 to 2016, reflecting that the growth of average service lives has been more rapid in recent years (Attorney General Brief at 151, citing

Exh. AG-MNL-Surrebuttal at 14-16; Attorney General Reply Brief at 50). Instead, the Attorney General argues that when using a nonlinear model to backcast average service life data, a 36-year average service life is more accurate (Attorney General Brief at 151-152, citing Exh. AG-MNL-Surrebuttal at 14-16; Attorney General Reply Brief at 50). The Attorney General asserts that the Company's backcasting exercise was motivated to legitimize the 33-year average service life used in another jurisdiction (Attorney General Reply Brief at 50, citing Exh. NG-MEM-Rebuttal-1, at 39-40). Further, the Attorney General contends that the average service life should be more representative of recent years rather than the midpoint of the Company's capital quantity index calculation period of 1964 through 2017 (Attorney General Brief at 152, citing Exh. AG-MNL-Surrebuttal at 13; Attorney General Reply Brief at 51-52). The Attorney General disagrees with the Company's claim that the backcasting of both trend lines to the beginning of the capital quantity index period supports the linear trend over the nonlinear trend (Attorney General Reply Brief at 50, citing Company Brief at 104-105). The Attorney General claims that both trend lines generate unreasonable results (Attorney General Reply Brief at 50-51, citing RR-NG-4). The Attorney General contends that its nonlinear trend was not, as the Company claims, performed without routine statistical testing (Attorney General Reply Brief at 51, citing RR-NG-4, at 3). Rather, the Attorney General maintains that the nonlinear trend is more accurate than the trend utilized by National Grid (Attorney General Reply Brief at 51, citing RR-NG-4, at 3, 6). The Attorney General also asserts that while the median of the nonlinear trend backcast beyond 1990 does rise, the lower range of values illustrates decreasing average service lives in earlier years (Attorney General Reply Brief at 51, citing RR-NG-4, at 4-6). The Attorney General disagrees with the Company's contention that the inclusion of generation assets in the Attorney General's average service life data resulted in faulty data (Attorney General Reply Brief at 52, citing Company Brief at 106). The Attorney General asserts that the inclusion of generation assets was limited to a single category, which was given a smaller weight (Attorney General Reply Brief at 52, citing Exh. NG-AG 2-23, Att. (a); Tr. 12, at 1629-1631).

Consequently, the Attorney General asserts that using the capital cost specification method known as geometric decay is free of many of the concerns she addresses in the one hoss shay method (Attorney General Brief at 153-156). The Attorney General maintains that the geometric decay method is not as sensitive to average service lives, which she asserts can be a source of uncertainty (Attorney General Brief at 153, citing Exh. AG-MNL-Surrebuttal at 16-17). The Attorney General claims that the change from a 33-year average service life to a 36-year average service life causes the industry productivity growth factor generated by the one hoss shay method to change from -0.13 percent to 0.30 percent (Attorney General Brief at 152, citing Exh. AG-MNL-2, at 28; Attorney General Reply Brief at 52). Conversely, the Attorney General states that the same change in average service life when used in the geometric decay method generates almost no change (Attorney General Reply Brief at 52, citing Exh. AG-MNL-Surrebuttal at 16). The Attorney General also asserts that the geometric decay method is more widely used in productivity studies than the one hoss shay method (Attorney General Brief at 153, citing Exh. AG-MNL-2, at 19). The Attorney

General argues that the Company's witness also has endorsed the use of geometric decay in the past (Attorney General Brief at 153-154, citing Exhs. AG 15-3(a); AG-MNL-Surrebuttal at 8; RR-AG-24; Attorney General Reply Brief at 49-50, citing Exh. AG-MNL-Surrebuttal at 29). The Attorney General argues that the geometric decay method better acknowledges that distribution assets can require increasing maintenance expense over an asset's life (Attorney General Brief at 153-154, citing Exhs. AG-MNL-Surrebuttal at 8; AG 15-3(f); Tr. 12, at 1613; Attorney General Reply Brief at 47 n.26). Further, the Attorney General asserts that the geometric decay method captures the declining costs of owning each cohort of utility assets as they depreciate over time, as well as the benefits of extending the use of assets beyond their average service lives (Attorney General Brief at 153; Attorney General Reply Brief at 48-49, citing Tr. 12, at 1602). The Attorney General also asserts that the geometric decay method better resembles the total flow of service from a heterogeneous cohort of assets (Attorney General Brief at 154, citing Exh. AG-MNL-Surrebuttal at 8; Attorney General Reply Brief at 47). The Attorney General contends that National Grid's criticism of the geometric decay method as being better suited for industries that have experienced rapid technical change is dubious since the Company's witness has used the geometric decay method in the past for industries that have not been known for this trait (Attorney General Brief at 154, citing Exhs. AG 23-3(c); AG 15-3(a); RR-AG-24). The Attorney General also contends that the Company's criticism of the geometric decay method for not resembling the straight-line depreciation used in utility ratemaking is hollow since the one hoss shay method does not capture depreciation of plant assets (Attorney General Brief at 154-155, citing Exhs. NG-NWA-Rebuttal-1, at 7-10; AG-MNL-Surrebuttal at 8-9). The Attorney General asserts that while geometric decay produces the largest amount of efficiency decay in the first year of an asset's life, what is important is the rate of physical decay when calibrating an X factor (Attorney General Brief at 148, citing Exh. AG-MNL at 11; Attorney General Reply Brief at 47).

The Attorney General also refutes the Company's assessment of the Attorney General's capital and total input price calculations as showing higher volatility, since she applies the smoothing method to a longer sample time period (Attorney General Brief at 155, citing Exh. NG-MEM-Rebuttal-1, at 52-54; Tr. 8, at 1213-1214; Tr. 12, at 1649-1650). The Attorney General contends that the use of a longer sample time period, larger sample size, and the geometric decay method results in a X factor of -0.71 percent (Attorney General Brief at 156, citing Exhs. AG-MNL at 16; AG-MNL-2, at 36).

The Attorney General also offers another alternative to the one hoss shay method of capital cost specification, the Kahn method, which calculates the trends in cost of base rate inputs of a sample of electric distribution companies and an approximation to traditional cost accounting (Attorney General Brief at 156, citing Exhs. AG-MNL at 16; AG-MNL-2, at 39). The Attorney General maintains that, in other jurisdictions, utility witnesses have recommended consideration of the Kahn method (Attorney General Reply Brief at 53 & n.28, citing Tr. 12, at 1555-1556). The Attorney General asserts that using this method with a sample time period of 1997 to 2017 would result in an X factor of -0.41 percent (Attorney General Brief at 156, citing Exhs. AG-MNL at 16; AG-MNL-2, at 39). The Attorney

General dismisses the Company's criticism of the Kahn method, and the Attorney General maintains that the Company's revised calculation ignores pertinent aspects of its own PBR proposal (Attorney General Brief at 156-157, citing Exh. AG-MNL-Surrebuttal at 25). The Attorney General argues that the Kahn method deploys the essential methodology of indexing an X factor reflective of industry productivity and input price differentials over a long sample period (Attorney General Reply Brief at 53-54). Further, the Attorney General asserts that the Kahn method as facilitated by her witness uses straight-line depreciation and historical plant valuations, which is similar to practices used in cost of service accounting (Attorney General Brief at 156, citing Exh. AG-MNL-Surrebuttal at 24; Attorney General Reply Brief at 54).

iv. Consumer Dividend

The Attorney General is critical of the Company's proposal regarding a consumer dividend that is contingent on inflation reaching at least two percent (Attorney General Brief at 158-159). The Attorney General asserts that this contingency would likely suspend the consumer dividend given recent low levels of inflation and, as such, will provide little benefit to consumers (Attorney General Brief at 158-159). The Attorney General also argues that an inflation contingency on consumer dividends is uncommon in PBR plans (Attorney General Brief at 159, citing Exh. AG-MNL-Surrebuttal at 35). While the Attorney General does not dispute the consumer dividend of 0.40 percent, she asserts that the inflationary trigger point of two percent should be adjusted to ensure that productivity gains are shared with ratepayers (Attorney General Brief at 158-159).

v. Earnings Sharing Mechanism

The Attorney General does not object to the inclusion of an earnings sharing mechanism as part of the proposed PBR Plan, but she disagrees with the Company's design of the mechanism (Attorney General Brief at 160). Specifically, the Attorney General contests the split of earnings sharing and the two tiers of the mechanism (Attorney General Brief at 160). The Attorney General asserts that the Department has previously determined that an earnings sharing mechanism should largely benefit ratepayers and should not be tiered to avoid concerns regarding incentives at the margin of the bands (Attorney General Brief at 160, citing D.P.U. 17-05, at 400-401). The Attorney General recommends that the Department approve an earnings sharing mechanism where earnings that exceed the deadband are split 75 percent with ratepayers and 25 percent with shareholders (Attorney General Brief at 160).

vi. PBR Adjusted Revenues

The Attorney General asserts that the revenues that are adjusted by the PBR mechanism should be revised to exclude all revenues associated with reconciling mechanisms (Attorney General Brief at 160). The Attorney General argues that costs from these programs can vary significantly from year to year and that the costs are ultimately recovered through specific reconciling mechanisms and, therefore, should be removed from base distribution rates (Attorney General Brief at 160-161). The Attorney General asserts that any costs that are proposed to be rolled into rate base, or will be proposed to be rolled into rate base in the future, would be subject to increased recovery through the annual PBR adjustments, which would lead to an over-collection of those costs (Attorney General Brief at 161-162). The Attorney General also asserts that the TFP study was based on distribution costs, which does not include solar and energy storage costs (Attorney General Brief at 162, citing Exh. AG-MNL-2, at 34-35; Tr. 8, at 1222). In addition, the Attorney General argues that any CIRM-related costs should be removed from the revenue cap formula (Attorney General Brief at 162-163). The Attorney General asserts that the CIRM costs decrease over time, and if they are included in the PBR revenue cap formula, the Company would recover increasing collections for these costs (Attorney General Brief at 163).

b. Acadia Center

Acadia Center argues that the Department should deny the proposed PBR unless three significant revisions are incorporated: (1) the X factor should be revised to reduce the rate increases generated by the PBR mechanism; (2) additional tracking metrics and a penalty mechanism must be included; and (3) the Company should be required to perform long-term planning and to consider non-wires alternatives (Acadia Center Brief at 6).[22] Acadia Center contends that a PBR plan that includes an X factor of -1.72 percent will cause rates to increase without necessarily providing benefits to customers (Acadia Center Brief at 7). Acadia Center asserts that a PBR plan with a large negative X factor is largely unprecedented and that other proposals with a negative X factor have been rejected (Acadia Center Brief at 7, citing Exhs. AG-MNL-1, at 5-8; AG 7-12). Accordingly, Acadia Center endorses the

---

[22] Acadia Center's positions regarding additional tracking metrics and non-wires alternatives are discussed in Section II.C., below.

X factor calculation of the Attorney General of -0.20 percent (Acadia Center Brief at 7, citing Exh. AG-MNL at 18).[23] Acadia Center also asserts that without linking National Grid's performance to its financial incentives, the PBR Plan does not hold the Company accountable and offers the Department limited transparency and recourse (Acadia Center Brief at 7).

c. Company

The Company argues that the Department should approve its PBR Plan, as proposed, as it will: (1) advance the goals of safe, reliable, and least-cost energy service; (2) incentivize cost control; (3) promote the Commonwealth's energy policies and statutory obligations; and (4) reduce administrative burdens associated with the regulatory process (Company Brief at 36, citing Exh. NG-PBRP-1, at 9). National Grid claims that the Company has experienced a 7.6-percent decline in kilowatt hour ("kWh") deliveries from 2003 to 2017, which is primarily due to increased energy efficiency (Company Brief at 34, citing Exh. NG-PBRP-1, at 22). National Grid asserts that a revenue decoupling mechanism approved by the Department only allows a utility to recover the revenue amount used to set base distribution rates from the last base distribution rate case (Company Brief at 34-35, citing Exh. NG-PBRP-1, at 23-24; Investigation into Rate Structures that Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A (2008)). The Company argues that historically, during a period of load growth, the electric distribution companies had access to

---

23 The Attorney General's X factor of -0.20 percent is the result of a base X factor of -0.60 percent and a 0.40 percent stretch factor (Exh. AG-MNL at 16-17).

increasing collections over the historic test year level (Company Brief at 35, citing Exh. NG-PBRP-1, at 24). National Grid claims that to address this issue, in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-39 (2009), the Department granted National Grid a revenue decoupling mechanism along with a CIRM that allowed incremental capital investment in between base distribution rate cases (Company Brief at 35, citing Exh. NG-PBRP-1, at 24-25). The Company argues that, while the CIRM was a positive addition, it does not provide revenue for capital investments that exceed the mechanism's cap, nor does it cover increasing O&M expenses over the amount approved in the last base distribution rate case (Company Brief at 35). National Grid asserts that it is experiencing changing capital investment requirements due to multiple drivers, including emerging technologies, increasing frequency and intensity of storms, and higher customer expectations (Company Brief at 31-34, citing Exh. NG-PBRP-1, at 16-18, 20-22, 26, 29-33, 35, 37-38, 41).

The Company asserts that its PBR proposal is better suited than traditional cost-of-service ratemaking and regulation to advance the Department's goals of safe, reliable, and least-cost energy service (Company Brief at 37, citing Exhs. NG-MLR-1, at 22, 37; NG-PBRP-1, at 6-7, 10, 12-13, 20-21; NG-MEM-1, at 5; NG-LRK-1, at 23, 52). National Grid contends that the Department has approved PBR proposals when it has been demonstrated that this alternative rate regulation would allow the utility to better satisfy public policy goals and statutory obligations at a lower costs to customers (Company Brief at 37, citing D.P.U. 17-05, at 370-414; Boston Gas Company, D.P.U. 96-50 (Phase I) at 261

(1996); Incentive Regulation, D.P.U. 94-158, at 42-43 (1995); New England Telephone and Telegraph Company, D.P.U. 94-50, at 139 (1995)). The Company argues that it designed the PBR mechanism proposal to be consistent with the Department's precedent (Company Brief at 38, citing D.P.U. 17-05, at 370-414; D.P.U. 96-50 (Phase I) at 259-339; D.P.U. 94-158, at 52-66).

National Grid contends that the Attorney General's justifications for rejecting the Company's proposed PBR are insufficient (Company Brief at 86). Specifically, National Grid asserts that the Attorney General's claim that PBR proposals are widely rejected is not supported by evidence (Company Brief at 90-93). The Company maintains that PBR plans do exist in other regions (Company Brief at 90-93, citing D.P.U. 17-05, at 361 n.181; Exh. DPU-AG 1-8). The Company further argues that many other regulatory bodies have approved a combination of factors that achieve the same result in terms of annual rate adjustments to support utility operations (Company Brief at 90, citing Exhs. NG-RBH-1, at 47-48; NG-RBH-9). The Company also contends that Massachusetts is a recognized leader in legislative and regulatory policies that promote clean energy goals, which is why its alternative ratemaking is at the forefront (Company Brief at 92-93).

i. PBR Term

National Grid disagrees with the Attorney General's argument that a five-year PBR term is inappropriate (Company Brief at 87-90). The Company points out that utilities have initially committed to five-year PBR terms with the assumption of a stay out during that period (Company Brief at 87, citing D.T.E. 03-40, at 436, 492; D.T.E. 05-27, at 359-360, 396-397). National Grid claims that the utilities could not ultimately sustain a ten-year stay out, which informed the Department that the anticipated efficiencies of PBR had not materialized (Company Brief at 87, citing D.T.E. 03-40, at 494-497; D.T.E. 05-27, at 399-401). The Company further asserts that in D.P.U. 96-50, the Department approved a five-year PBR term for Boston Gas Company ("Boston Gas") and found that it had produced benefits (Company Brief at 87, citing D.T.E. 03-40, at 494-497). The Company maintains that for Boston Gas's second PBR, the plan was terminated after six years, which was a year longer than the utility had initially proposed (Company Brief at 87-88). The Company asserts that the PBR plan was terminated early due to changing circumstances between 2003 and 2010, which lead to the data used to calculate the PBR becoming outdated (Company Brief at 88, citing Boston Gas Company/Essex Gas Company/Colonial Gas Company, D.P.U. 10-55, at 11, 16 (2010)). National Grid also asserts that the PBR term of ten years for Bay State Gas Company in 2005 proved to be too long to foresee the changes in the operating environment, such as reductions in sales volumes (Company Brief at 88-89, citing D.T.E. 05-27). These examples, the Company contends, are evidence that PBR terms longer than five years have failed to realistically accommodate utilities' actual operating conditions (Company Brief at 89).

ii. X Factor

(A) Introduction

The Company rejects the Attorney General's arguments for changes to the components of its proposed X factor (Company Brief at 94-108). Specifically, the Company refutes the

Attorney General's arguments regarding (1) the sample time period, (2) the sample size of electric distribution companies, and (3) the capital cost specification method (Company Brief at 94-108). The Company contends that the criticisms from the Attorney General are baseless and merely aimed at manipulating the X factor (Company Brief at 94, citing Tr. 12, at 1653). Further, National Grid contends that the Attorney General's counter proposals for an X factor do not consider that the Company's PBR Plan is intended to replace the CIRM and allow the Company the flexibility and revenue to enter into a five-year stay-out period (Company Reply Brief at 16-17). The Company states that the Attorney General's proposed X factors do not consider the need to address (1) the loss of sales growth to support utility operations between base distribution rate cases, (2) the termination of the annual revenue collected through the CIRM, and (3) the fact that the Company's PBR Plan includes a five-year stay-out provision (Company Reply Brief at 17).

The Company argues that the Attorney General's X factors are biased toward offering a less negative factor, rather than focused on the purpose and goals of the PBR Plan (Company Reply Brief at 17-18). The Company argues that the alternative X factors do not consider National Grid's operating environment, such as the absence of sales growth (Company Reply Brief at 18). The Company contends that the Attorney General's witness is unfamiliar with the Company's capital expenditures and did not consider the CIRM replacement as a part of his testimony (Company Reply Brief at 18-19, citing Tr. 12, at 1520-1522, 1551).

Further, National Grid asserts that it has been established that a company cannot be barred from requesting a base distribution rate case, and that any stay-out provision would be entered into on a voluntary basis (Company Reply Brief at 20-21, citing G.L. c. 164, § 94; Fitchburg Gas and Electric Light Company, 371 Mass. 881, 884 (1977); Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 10-12, , cert. denied, 439 U.S. 921 (1978); Massachusetts Electric Company v. Department of Public Utilities, 376 Mass. 294, 299-300 (1978)). The Company also cites the Supreme Judicial Court's decision that found that the Department is obligated to determine the propriety of proposed rates when gas and electric utilities request a general rate increase under G.L. c. 164, § 94 (Company Reply Brief at 20, citing Attorney General v. Department of Telecommunications and Energy, 438 Mass. 256, 268 (2002)).

In addition, National Grid criticizes the recommendation of the Attorney General to consider selecting an X factor from a range of methods (Company Reply Brief at 21, citing Attorney General Reply Brief at 43-44). The Company claims that this proposal is contradictory to the testimony of the Attorney General's witness (Company Reply Brief at 21, citing Tr. 12, at 1538, 1539-1540). The Company argues that the Attorney General's suggestion to select an X factor from a range of studies creates subjectivity and hinders transparency of the entire PBR framework (Company Reply Brief at 22). The Company contends that Department has based its decisions regarding PBR proposals on methodological principles (Company Reply Brief at 23).

(B) TFP Sample Time Period

The Company refutes the Attorney General's argument that the sample time period of 2002 through 2016 should be extended back to 1996 (Company Brief at 95-97). The Company argues that the Attorney General's witness was unable to identify an instance in which he recommended such a long time period for a TFP study (Company Brief at 96, citing Tr. 12, at 1657-1658). The Company further asserts that the Attorney General's witness recently recommended a ten-year sample period (Company Brief at 96, citing Tr. 12, at 1655-1657). National Grid contends that the Attorney General's argument against the 15-year sample period is overly reliant on the premise that the period includes a steep growth in regional power distribution construction costs and copper prices (Company Brief at 96-97, citing Attorney General Brief at 144). The National Grid argues that these observed costs are relevant to the Company's cost structure (Company Brief at 96-97). The Company also asserts that the Attorney General fails to provide any supporting evidence for her assertion that the observed uptick in costs is not likely to repeat itself (Company Brief at 96-97, citing Attorney General Brief at 144; Company Reply Brief at 24, citing Attorney General Reply Brief at 45 n.25). Given that the Attorney General's argument is not supported by evidence, the Company claims that Department is obligated to rest its decisions on evidence that a reasonable mind might accept as adequate to support a conclusion (Company Reply Brief at 25, citing Massachusetts Electric Company v. Department of Public Utilities, 469 Mass. 553, 563 (2014)). The Company also asserts that the capital and total input price calculations offered by the Attorney General exhibit much more volatility than calculations proposed by National Grid (Company Brief at 96-97; Company Reply Brief at 25-26, citing Exh. NG-MEM-Rebuttal-1, at 53). In addition, the Company contends that the Attorney General's use of a longer sample period is not supported by any methodological basis and is motivated by manipulating the X factor to make it less negative (Company Reply Brief at 23-24, citing Tr. 12, at 1653). National Grid argues that extension of the sample period by six years is not supported by any evidence offered by the Attorney General and runs the risk of capturing data from years that are not representative of the current environment of the electric distribution industry (Company Reply Brief at 26, 28). Further, the Company maintains that the 15-year sample is longer than, or equal to the sample periods approved by the Department in past PBR decisions (Company Reply Brief at 27, citing D.P.U. 17-05, at 384; D.T.E. 03-40, at 477; D.P.U. 96-50 (Phase I) at 3, 263). The Company argues that, in this case, a 15-year period balances the most recent data relevant to the PBR term, such as technological advancements, with a long enough term to account for short-term variation (Company Reply Brief at 27-28, citing Exhs. NG-MEM-1, at 33; DPU-NG 13-7).

(C) TFP Sample Size

National Grid rebuts the Attorney General's claim that the sample size used by the Company is not sufficiently large (Company Brief at 97-99). The Company asserts that its sample represents 71 percent of electric distribution customers nationwide, compared to the 78 percent of electric distribution customers served nationwide utilized by the Attorney General (Company Brief at 97). National Grid claims that the Attorney General did not provide any evidence to demonstrate that her sample was any more representative of the industry (Company Reply Brief at 48). The Company also asserts that the Attorney General conceded that the average sizes of the companies in the samples are only modestly different (Company Brief at 97, citing Attorney General Brief at 147-148). National Grid claims that the primary difference in the samples used by the Attorney General and the Company is the method of averaging the companies within the sample sets (Company Brief at 97). The Company states that by weighting the companies within its sample, by number of customers served, the calculation provides a result that is more representative of the industry (Company Brief at 97-98, citing Exh. NG-MEM-1, at 28; Company Reply Brief at 49). The Company argues that the Attorney General's approach of performing a simple average provides a result that has a lopsided influence from the smaller companies in the sample, which National Grid asserts would not experience similar rates of customer growth as the larger companies (Company Brief at 98-99, citing Exh. NG-AG-1, Att. PEG_WP). Further, the Company disagrees with the Attorney General's claim that observing economies of scale is implicated in the weighting methodology in National Grid's sample (Company Reply Brief at 48-49). Rather, the Company asserts that it weighted the companies within its sample by customers because electric distribution output is measured by customers (Company Reply Brief at 49, citing Exh. NG-MEM-Rebuttal-1, at 28).

(D) Capital Cost Specification Method

The Company asserts that the Department should reject the Attorney General's argument that using a geometric decay method for calculating capital costs is more appropriate than using a one hoss shay method (Company Brief at 99-106). National Grid rejects the Attorney General's claim that the one hoss shay method does not consider gradual depreciation, maintaining that the method does include the decline in the value of assets (Company Brief at 99, citing Exh. NG-MEM-Rebuttal-1, at 23-24). National Grid also states that the assertion that the geometric decay method is more commonly used in productivity studies is erroneous (Company Brief at 99-100, citing Attorney General Brief at 153). The Company contends that this assertion relies on the use of the geometric decay method in the telecommunications industry, which is unique from the electric distribution industry due to the period of rapid obsolescence that the telecommunications industry observed (Company Brief at 100, citing Tr. 12, at 1663; Company Reply Brief at 30-31). Further, the Company claims that the Attorney General fails to provide any examples of the geometric decay method being used specifically for the electric distribution industry due to technological innovation (Company Brief at 100, citing Exh. NG-MEM-Rebuttal-1, at 31-32). The Company states that the examples provided are used to study a single pattern of asset decay for many or all industries or very broad classes of assets (Company Brief at 100, citing Exh. NG-MEM-Rebuttal-1, at 31-32). National Grid further argues that the one hoss shay method was considered in the proceedings in Alberta, Canada, which focused on the electric distribution industry (Company Brief at 101, citing Exhs. AG-MNL at 11; AG 15-3; AG 15-4; AG 23-8; DPU-NG 13-8). The Company criticizes the Attorney General's argument that the Department does not need to approve the use of one hoss shay simply because it was approved for an electric distribution company two years ago, and National Grid asserts that the Attorney General's examples supporting geometric decay are from more than ten years ago (Company Reply Brief at 22, citing Exh. AG-MNL at 13; Tr. 12, at 1527; RR-AG-24). Further, National Grid contends that the Attorney General fails to address that the Company's witness used the one hoss shay method in two prior proceedings involving electric distribution companies (Company Reply Brief at 22, citing RR-AG-24).

The Company also rebuts the Attorney General's claim that the geometric decay method is used to measure the multi-factor productivity trends by U.S. and Canadian governments (Company Brief at 101, citing Attorney General Brief at 153). Instead, the Company argues that the method used by the U.S. Bureau of Labor Statistics is more similar to the one hoss shay method than to the geometric decay method (Company Brief at 101, citing Exh. NG-MEM-Rebuttal-1, at 32; Tr. 12, at 1610-1612). In addition, National Grid contends that the geometric decay method's assumption that loss of productivity is largest in the first year of an asset's life is inconsistent with the trends observed in the electric distribution industry (Company Brief at 101, citing Exh. NG-MEM-Rebuttal-1, at 30; Company Reply Brief at 29, citing Exh. NG-NWA-Rebuttal-1, at 7). The Company further claims that the geometric decay method depreciation pattern resembles accelerated depreciation, rather than a straight-line trend as used in the depreciation of assets for ratemaking purposes (Company Reply Brief at 29-30). The Company asserts that the one hoss shay method results in a change in value that is more consistent with straight-line depreciation (Company Reply Brief at 32, citing Exh. NG-NWA-Rebuttal-1, at 6-8). National Grid states that the bulk of electric distribution assets function at design level until taken out of service, which the Company contends resembles the one hoss shay pattern of decay (Company Reply Brief at 30, citing Exh. NG-AG 2-48; Tr. 12, at 1605-1609). Thus, the Company asserts that the one hoss shay method better resembles the pattern of decay for electric distribution assets (Company Brief at 102; Company Reply Brief at 29-30). National Grid contends that no evidence was provided to defend the argument that the rate of decay in electric distribution assets aligns with the accelerated depreciation demonstrated by the geometric decay method (Company Reply Brief at 32). The Company disagrees with the Attorney General's argument that the geometric decay method resembles the depreciation pattern of a group of heterogeneous group of assets, and the Company maintains that the Attorney General has not provided any evidence to illustrate this effect (Company Reply Brief at 33, citing Exhs. AG-MNL-2, at 18; AG-MNL-Surrebuttal at 9; NG-AG 2-48).

In addition, the Company contends that the Attorney General did not support with any research or analysis her claim that groups of assets experience a decay in their flow of services or require increasing maintenance expenses as they age (Company Reply Brief at 33-34, citing Exh. NG-AG 2-48; Tr. 12, at 1605-1606; 1608, 1609). The Company maintains that it has presented expert testimony demonstrating that the actual pattern of decay of electric distribution assets is better represented by the one hoss shay method (Company Reply Brief at 34, citing Exh. NG-NWA-Rebuttal-1, at 10-17). The Company argues that geometric decay's accelerated depreciation in earlier years does not match the dispersion of electric distribution asset lives, as predicted by the Iowa survivor curves proposed in this proceeding (Company Reply Brief at 35, citing Exh. NG-NWA-Rebuttal-1, at 14-17).

The Company refutes the Attorney General's criticism of the 33-year average service life used in National Grid's capital cost specification method (Company Brief at 103-106). The Company asserts that the Attorney General's modifications of the average service life are biased and meant to manipulate the resulting X factor (Company Brief at 103, citing Attorney General Brief at 151). National Grid contends that criticism that average service lives have not risen linearly from 1994 through 2016, is not supported by statistical tests (Company Brief at 104, citing Tr. 12, at 1605; Company Reply Brief at 37, citing Tr. 12, at 1637). The Company asserts that when the Attorney General's non-linear trend of average service lives is extended back to produce results for the beginning of the capital quantity index calculation, it produces a value of 45 years in 1964 (Company Brief at 105; Company Reply Brief at 37, citing RR-NG-4). The Company claims that this result is inconsistent with the trend of average service lives increasing over time, and, therefore, is a deficiency in the Attorney General's trend line (Company Brief at 105; Company Reply Brief at 38-39). The Company also states that its average service life of 33 years is nearly within the Attorney General's confidence range for the year 1990, making it a viable option for either trend line (Company Reply Brief at 40, citing RR-NG-4). Conversely, the Company contends that when its linear trend line is backcast to the beginning of the capital quantity index period, it produces a value of 22 years in 1964, which National Grid asserts makes it a more plausible trend line for the entire period (Company Brief at 105, citing RR-NG-4). In support of the Company's 33-year average service life, National Grid states that its value for each year of the capital quantity period averaged together is the same as the midpoint value, which makes the midpoint the most reasonable proxy for estimating average service life (Company Reply Brief at 41-42). The Company further argues that a second method used by the Attorney General to justify the 36-year average service life is invalid because it includes data from electric generation assets (Company Brief at 105-106, citing Tr. 12, at 1628-1632; Company Reply Brief at 42, 44). In addition, the Company argues that the year 1996 does not have any particular significance in the capital quantity period of 1964 through 2016 (Company Reply Brief at 42, 44-45). National Grid also argues that the average service life of 36 years generated from this method is highly sensitive to the weight provided to the separate categories, which were at the discretion of the Attorney General (Company Reply Brief at 43-44, citing Tr. 12, at 1634-1635). Further, the Company contends that if the appropriate weights are given to the "structures" and "equipment" categories as described by Federal Energy Regulatory Commission ("FERC"), then the weighting exercise generates an average service life of 33.1 years (Company Reply Brief at 45, citing Exh. NG-AG 2-23(a); Tr. 12, at 1628-1632). Lastly, the Company states that when a 36-year average service life is used in its model, constant dollar retirements exceed the constant dollar investments for a number of companies in the sample and company capital stocks decrease in magnitude over time, which is counterintuitive and demonstrates that the 36-year value is unsubstantiated (Company Reply Brief at 45-46, citing RR-DPU-26).

The Company argues that the results presented by the Attorney General from the Kahn method also should be rejected (Company Brief at 106-108). The Company contends that this X factor calibration is based on a method developed by Dr. Alfred Kahn, but that the Attorney General substantially modified it, which diminishes its legitimacy (Company Brief at 106-107, citing Tr. 12, at 1567). As an example, the Company notes that the Attorney General offers the use of a 21-year time period with this method, while Dr. Kahn has never used a period longer than ten years (Company Reply Brief at 46). National Grid also maintains that FERC uses Dr. Kahn's method to calculate an X factor and has consistently used five-year terms (Company Brief at 107, citing Exh. NG-MEM-Rebuttal-1; Company Reply Brief at 46). In addition, the Company asserts that the original method developed by Dr. Kahn does not employ the use of GDP-PI, for an inflation index, which the Attorney General uses in her Kahn method (Company Reply Brief at 46-47). The Company argues that utilizing the original Kahn method, which is used by FERC, generates an X factor of -2.40 percent, as opposed to the Attorney General's calculation of -0.41 percent (Company Brief at 107, citing Exh. NG-MEM-Rebuttal-1). Accordingly, the Company contends that the X factor of -0.41 percent is a manipulated result, and it is not based on the actual Kahn method (Company Brief at 107-108, citing Tr. 12, at 1559-1565, 1568). Further, the Company asserts that this method has not been adopted in any other jurisdiction outside of FERC (Company Reply Brief at 47, citing Tr. 12, at 1555).

iii. Consumer Dividend

The Company defends its proposal for a consumer dividend of 0.40 percent when inflation exceeds two percent (Company Brief at 108-111). National Grid argues that it is well-established in economic theory that performance incentives do not depend on the value of the X factor, which necessarily includes the consumer dividend (Company Brief at 109).

National Grid further contends that a consumer dividend does not undermine the Company's incentive to pursue efficiencies (Company Brief at 109, citing Exh. NG-LRK-Rebuttal-1, at 13; Tr. 8, at 1245; Company Reply Brief at 50-52, citing Exhs. NG-LRK-1, at 30-31, 48). National Grid argues that PBR plans commonly include components to mitigate risk to the company (Company Brief at 109). The Company asserts that its proposal, including a consumer dividend contingent on inflation, is superior to other proposals in its balance of creating incentives and mitigating risk (Company Brief at 109-110, citing Exh. NG-LRK-Rebuttal-1, at 14-15). Specifically, the Company asserts that its consumer dividend being contingent on a two-percent inflation trigger is designed to offset the risk of unremunerated capital expenditures, which is essential for the Company to transition from the CIRM to a PBR plan (Company Brief at 110; Company Reply Brief at 53). Further, the Company maintains that the Department has rejected the argument that customers will not accrue an appropriate share of benefits if the consumer dividend is contingent on a two-percent inflation factor (Company Brief at 110, citing D.P.U. 17-05, at 395).

iv. Earnings Sharing Mechanism

The Company claims that its proposed two-tiered, earnings sharing mechanism is superior to the design proposed by the Attorney General (Company Brief at 111-112). National Grid asserts that the first tier of its proposed earnings sharing mechanism creates a stronger performance incentive for the Company (Company Brief at 111). Additionally, National Grid contends that the second tier of its proposed earnings sharing mechanism distributes more benefits to customers and essentially eliminates the potential for the

Company to earn unreasonable returns (Company Brief at 111-112, citing Exh. NG-LRK-1, at 47).

v. PBR Adjusted Revenues

National Grid contends that the Attorney General's recommendations to adjust the revenues to which the PBR mechanism is applied are either unnecessary or inappropriate (Company Brief at 112-113). The Company asserts that the PBR mechanism is applied to the approved base distribution revenue requirement, which is collected through base distribution rates (Company Brief at 112, citing Exh. NG-HSG-12, Proposed M.D.P.U. No. 1400). The Company further states that there is no differentiation within the base revenue requirement as to categories of expenses or investments to which the PBR mechanism would apply, with the exception of the annual contribution to the storm fund and the major storm event deductible amount (Company Brief at 113, citing Exh. NG-HSG-12, Proposed M.D.P.U. No. 1400). National Grid further argues that, with the exception of the plant additions through the CIRM transitional period, all new capital additions made by the Company will not be included in the base distribution revenue requirement until the next time base distribution rates are set (Company Brief at 113).

4. Analysis and Findings

a. Introduction

In the sections below, we review our ratemaking authority and reaffirm that, pursuant to G.L. c. 164, § 94, the Department may implement PBR as an adjustment to cost of service/rate of return regulation. Further, we discuss the factors that the Department has used to review incentive regulation proposals. Finally, we review the Company's PBR Plan to determine whether it 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 electric and gas distribution companies. The Supreme Judicial Court has consistently found that the Department's authority to design and set rates is broad and substantial. See, e.g., Boston Real Estate Board v. Department of Public Utilities, 334 Mass. 477, 485 (1956). Because G.L. c. 164, § 94, authorizes the Department to regulate the rates, prices, and charges that electric and gas distribution companies may collect, this authority includes the power to implement revenue adjustment mechanisms such as a PBR. Boston Gas Company v. Department of Telecommunications and Energy, 436 Mass. 233, 234-235 (2002).

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). 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 376 Mass. 294, 302.

In addition, G.L. c. 164, § 76, grants the Department broad supervision over electric and gas distribution companies. Under G.L. c. 164, § 76, the Department has the authority to establish reasonable rules and regulations consistent with G.L. c. 164, as needed, to carry out its administration of jurisdictional companies in the public interest. D.P.U. 07-50-B at 26-27. See also Cambridge Electric Light Company v. Department of Public Utilities, 363 Mass. 474, 494-496 (1973).

Although the Department traditionally has relied on cost of service/rate of return regulation to establish just and reasonable rates, there are many variations and adjustments in the specific application of this model to individual utilities as circumstances differed across companies and across time. D.P.U. 07-50, at 8. Over the years, electric and gas distribution companies subject to the Department's jurisdiction have operated under PBR or PBR-like plans. See e.g., D.P.U. 17-05, at 371-372; D.T.E. 05-27, at 382; D.T.E. 03-40, at 471; The Berkshire Gas Company, D.T.E. 01-56, at 10 (2002); Massachusetts Electric Company/Eastern Edison Company, D.T.E. 99-47, at 4-14 (2000).

Consistent with the discussion above, the Department reaffirms that we may implement PBR as an adjustment 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.[24] The standards by which the Department will review the Company's specific PBR proposal are addressed below.

---

24 In addition, pursuant to G.L. c. 164, § 1(E), the Department is authorized to promulgate rules and regulations to establish and require performance-based rates for gas and electric distribution companies.

c. Evaluation Criteria for PBR

The Department must approach the setting of rates and charges in a manner that: (1) meets our statutory obligation 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 PBRs or PBR-like mechanisms on a finding that such regulatory methods would better satisfy our public policy goals and statutory obligations. See, e.g., D.P.U. 96-50 (Phase I) at 261; D.P.U. 94-158, at 42-43; D.P.U. 94-50, at 139.

As part of our generic investigation of incentive ratemaking in D.P.U. 94-158, at 52-66, the Department examined the criteria by which PBR proposals for electric and gas distribution companies would be evaluated. 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. Further, the Department determined that a petitioner seeking approval of an incentive regulation proposal like PBR is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. D.P.U. 94-158, at 57. Finally, a well-designed incentive mechanism should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers that are greater than would be present under current regulation. D.P.U. 94-158, at 57.

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

d. Rationale for PBR

There is a fundamental evolution taking place in the way electricity is produced and consumed in Massachusetts. This evolution has been driven, in large part, by a number of legislative and administration policy initiatives designed to address climate change and to foster a clean energy economy through the promotion of energy efficiency, demand response, and distributed energy resources ("DER"), and the procurement of long-term contracts for renewable energy. An Act Relative To Green Communities, St. 2008, c. 169; An Act Establishing the Global Warming Solutions Act, St. 2008, c. 298 ("Global Warming Solutions Act"); An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, § 36; Green Communities Expansion Act, § 83A; Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016). To varying degrees, this evolution is changing the operating environment for electric distribution companies in Massachusetts.

As described above, National Grid proposes to implement a PBR mechanism that would adjust rates annually in accordance with a revenue cap formula (Exhs. NG-MLR-1, at 10; NG-PBRP-1, at 42). The Company states that, given specific changes that have taken place as a result of the Commonwealth's aggressive efforts to achieve clean energy goals, the Company no longer can operate effectively under cost of service regulation (Exhs. NG-MLR-1, at 11, 18-22; NG-PBRP-1, at 16). The Company states that a PBR plan is essential to offset the effects of increasing operating and capital costs as it is no longer able to retain sales growth revenues between base distribution rate cases after decoupling (Exh. NG-PBRP-1, at 24). And, unlike a capital cost recovery mechanism, National Grid notes that the proposed PBR Plan is designed to provide it with strong incentives to control costs (Exhs. NG-MLR-1, at 10; NG-PBRP-1, at 14).

Conversely, intervenors argue that the Company's proposed PBR Plan is not in the public interest and should be rejected or modified (Attorney General Brief at 137-138; Acadia Center Brief at 6-7). The Attorney General argues that National Grid fails to demonstrate that its proposed PBR will achieve any specific, measurable results, in contravention to Bay State Gas Company, D.P.U. 09-30, at 24-25 (2009) (Attorney General Brief at 137). Rather, the Attorney General contends that the PBR proposal excessively focuses on cost recovery, which violates Department precedent (Attorney General Brief at 135, citing D.P.U. 09-30, at 24-25; D.P.U. 96-50 (Phase I) at 242).

For the reasons discussed below, the Department finds that National Grid has demonstrated that an alternative to traditional cost of service/rate of return ratemaking is warranted. Further, the Department finds that, based on the evidence presented in this case, the Company has demonstrated that PBR, as compared to a capital cost recovery mechanism, will provide it with greater incentives to reduce costs and will result in benefits to customers that are greater than would be present under current regulation.

National Grid has demonstrated that a primary effect of the Commonwealth's clean energy efforts has been a decline in its levels of kWh sales (Exhs. NG-MLR-1, at 31-33; NG-PBRP-1, at 22; DPU-NG 13-3, Att.). As a result, from 2013 through 2017, the Company experienced a decline in sales of 7.6 percent (Exh. NG-PBRP-1, at 22). National Grid has also shown that its distribution system is growing and that its capital and operating costs are increasing in ways that it has not experienced in the past, partly driven by integrating DER with its distribution system (Exhs. NG-MLR-1, at 25-27; NG-PBRP-1, at 26, 29, 31-33, 35-36). Other factors driving National Grid's increasing costs include the rising frequency and severity of storms, adapting to changes in customer preferences, cyber-security needs, and meeting the aggressive goals of the Commonwealth's climate change policies (Exhs. NG-MLR-1, at 11, 22-23, 24-25; NG-PBRP-1, at 21, 35, 37-39; NG-PBRP-3, at 19).

Between base distribution rate cases prior to revenue decoupling, electric distribution companies, such as National Grid, traditionally had relied on revenues from sales growth to fund capital investments intended to ensure safe and reliable service (Exh. NG-PBRP-1, at 24). See, e.g., D.P.U. 15-155, at 22-23, 40; Fitchburg Gas and Electric Light Company, D.P.U. 13-90, at 35 (2014); Western Massachusetts Electric Company, D.P.U. 10-70, at 47 (2011). While revenue decoupling protects existing sales revenues, it does not address the loss of sales growth revenues between base distribution rate cases (Exh. NG-PBRP-1, at 24; Tr. 8, at 1052).[25]

In response to revenue decoupling, the Department has allowed companies to adopt various 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 cases. D.P.U. 15-155, at 40, 51-54; Fitchburg Gas and Electric Light Company, D.P.U. 15-80/D.P.U. 15-81, at 50 (2016); 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. In this proceeding, the Company is proposing to transition from its CIRM to a PBR mechanism

[25] In 2008, the Department implemented revenue decoupling to remove the disincentive for electric and gas distribution companies to invest in measures, such as energy efficiency, that reduced sales. D.P.U. 07-50-A at 4. The Department found that revenue decoupling (1) aligns the financial interests of the companies with policy objectives regarding the efficient deployment of demand resources and (2) ensures that the companies are not harmed by decreases in sales associated with any increased use of demand resources. D.P.U. 07-50-A at 31-32, 48-50.

(Exh. NG-PBRP-1, at 25). The Department finds that a PBR mechanism provides the Company more flexibility to address a changing operating environment, such as emerging technologies, increasing frequency and intensity of storms, and higher customer expectations (Exhs. NG-MLR-1, at 11; NG-PBRP-1, at 16-18, 20-22, 26, 29-33, 35, 37-38, 41). The approach we adopt addresses lost sales growth and allows National Grid to best meet its public service obligations in terms of providing safe, reliable, and least-cost service to customers as well as ensure that the Commonwealth's clean energy goals are met. D.P.U. 94-158, at 57.

As part of the PBR Plan, the Company has committed to refraining from filing rate schedules to put new base distribution rates into effect during the PBR term (Exh. NG-PBRP-1, at 47). The Department accepts that this stay-out provision will generate diminished administrative burden and will result in efficiencies (Tr. 3, at 381-382; Tr. 8, at 1089-1094; RR-AC-1). In addition, review of capital cost recovery mechanism filings can result in significant administrative burden and expense as compared to review of annual PBR filings, which should be less complex and require fewer resources. See, e.g., D.P.U. 15-155, at 36, 60, 86-89, 136. Accordingly, the Department finds that the transition from the CIRM to the PBR will result in a reduced administrative burden and is in the public interest (Exhs. NG-MLR-1, at 5, 10; NG-PBRP-1, at 14).

In addition, the Department finds that National Grid has demonstrated that a PBR mechanism is superior to a capital cost recovery mechanism in terms of its ability to satisfy the Department's public policy goals and statutory obligations. Rather than directing its focus on specific capital investments, PBR will provide the Company with greater incentives to be efficient and allow it to focus on developing innovative solutions in furtherance of the Commonwealth's clean energy goals (Exhs. NG-MLR-1, at 10; NG-PBRP-1, at 11-12; Tr. 3, at 339, 378-379; Tr. 8, at 1042-1043).

Finally, we are not persuaded by the Attorney General's argument that the Company's proposal overly focuses on cost recovery. As described in below, the Department has approved a number of PBR-specific scorecard metrics to measure the Company's performance and the full range of benefits that will accrue under the PBR with the goal of assuring customers and stakeholders that standards of service are maintained or improved, and clean energy goals are met during the PBR term. Below, the Department addresses the PBR formula elements and whether the proposed formula appropriately balances ratepayer and shareholder risk, is in the public interest, and will result in just and reasonable rates.

e. PBR Formula Elements

i. PBR Term

National Grid included a pre-defined term of five years for the PBR Plan (Exhs. NG-PBRP-1, at 9; NG-LRK-1, at 8, 56). The five-year PBR term would commence on October 1, 2019 and expire on September 30, 2024 (Exh. NG-PBRP-1, at 47). Within the five-year term, the Company proposes four annual PBR mechanism adjustments taking effect October 1, 2020, October 1, 2021, October 1, 2022, and October 1, 2023 (Exh. NG-PBRP-1, at 47). In conjunction with the PBR term, National Grid proposed a stay-out provision during which the Company commits to file for rate schedules to put new base distribution rates into effect no earlier than October 1, 2024 (Exh. NG-PBRP-1, at 47). The Attorney General argues that the Department has found that a five-year PBR term is not long enough to achieve the expected efficiencies and benefits of a PBR plan (Attorney General Brief at 137 n.65, citing D.T.E. 03-40, at 495). The Attorney General further argues that the Department has been more favorable to ten-year PBR plans since they provide more time for efficiency planning and can provide stronger incentives to companies (Attorney General Brief at 137 n.65, citing D.T.E. 05-27, at 399).

The Department has found that a well-designed PBR should be of sufficient duration to give the plan enough time to achieve its goals and to provide utilities with the appropriate economic incentives and certainty to follow through with medium- and long-term strategic business decisions. D.P.U. 96-50 (Phase I) at 320; D.P.U. 94-158, at 66; D.P.U. 94-50, at 272. In addition, the Department has stated that one benefit of incentive regulation is a reduction in regulatory and administrative costs. D.P.U. 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 years or longer. See, e.g., D.P.U. 17-05, at 404 (five years); D.T.E. 01-56, at 10 (ten years); D.P.U. 96-50 (Phase I) at 320 (five years). In the instant case, the Department finds that a five-year term will give the plan sufficient time to achieve its goals and will provide the Company with the appropriate economic incentives for cost containment and long-term planning. A stay-out provision provides an important benefit to ratepayers as it will ensure that there are strong incentives for cost containment under the PBR. D.P.U. 17-05, at 403.

Accordingly, the Department adopts a stay-out provision in conjunction with the five-year term.

For the reasons discussed above, the Department finds that the Company's PBR shall operate for a five-year term starting October 1, 2019. Additionally, the Company shall not file a proceeding under G.L. c. 164, § 94, that seeks to change base distribution rates prior to the end of the PBR term.

ii. X Factor

(A) Introduction

In the context of a PBR that uses an economy-wide measure of inflation, a productivity offset (or X factor) 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 (Exhs. NG-MEM-1, at 21; NG-PBRP-1, at 44). As described above, National Grid conducted multiple TFP studies and ultimately proposed an X factor in the instant case equal to -1.72 percent (Exhs. NG-MEM-1, at 44, 48; NG-PBRP-1, at 44). The Attorney General also conducted multiple TFP studies that produced a range of X factor results from 0.04 percent to -0.74 percent (Exh. AG-MNL at 16). The X factors produced by the Attorney General's TFP studies differ from the Company's recommended TFP study in several ways, which the Department reviews in the sections below. In the subsequent sections, the Department details its decision to accept the Company's proposed X factor of -1.72 percent to be used in the PBR mechanism.

(B) TFP Sample Time Period

The Company's TFP study utilized a 15-year time period from 2002 through 2016 (Exh. NG-MEM-1, at 33). This time period was intended to balance the most recent, relevant information within a long enough period to overcome transient, short-term occurrences that could inappropriately skew the results of the TFP study (Exh. DPU-NG 13-7). Specifically, the Company states that if years prior to 2002 were included, the sample period would capture the effects of technological advancements, such as computerization and automation, which were being implemented in that time, but are now fully incorporated into the Company's operations (Exh. DPU-NG 13-7). The Attorney General offered multiple competing TFP studies that examined a 21-year sample time period, from 1996 through 2016 (Exh. AG-MNL-Surrebuttal at 22). The Attorney General extended the time frame of her TFP study time period, because she claims that the 15-year period is characterized by unusually rapid growth in regional power distribution construction costs and copper prices from 2005 to 2009, which are unlikely to be repeated (Exhs. AG-MNL at 8-9; AG-MNL-2, at 26-27; Tr. 12, at 1653). Based on the technological changes that the electric distribution industry underwent prior to 2002 and the Department's prior approved PBR plans, we accept that a 15-year period is appropriate in the instant case (Exh. DPU-NG 13-7). D.P.U. 17-05, at 384; D.T.E. 05-27, at 362; D.T.E. 03-40, at 477; D.P.U. 96-50 (Phase I) at 263.

(C) TFP Sample Size

National Grid's proposed X factor of -1.72 percent was generated using a national sample of 66 electric distribution companies (Exh. NG-MEM-1, at 33). As measured by customers served, the Company's sample represents 71 percent of electric distribution customers nationwide (Exh. NG-MEM-Rebuttal-1, at 28). The Attorney General conducted a competing TFP study that utilized a national sample of 80 electric distribution companies, which represents 78 percent of electric distribution customers served nationwide (Exh. AG-MNL-2, at 32; RR-DPU-31). A key difference in the uses of these samples was how the data from the sample companies was averaged. The results of the Company's TFP study employs a weighted average of the sample companies, meaning companies serving more customers in the sample have a larger impact on the result (Exh. NG-MEM-Rebuttal-1, at 28). Conversely, the Attorney General uses a simple average of the sample companies, meaning the results of each company were considered equally, regardless of size (Exh. AG-MNL-Surrebuttal at 19). While generally speaking, a larger sample size of companies is more representative of the industry, we find that the Company's sample of national electric distribution companies is of sufficient size to be representative of the industry for the purpose of determining the X factor. While we also are not convinced that the weighting of companies by number of customers leads to a more representative industry average, we find that the difference in the results using a simple average is not significant enough as to warrant a change to the Company's study. Accordingly, we find that the Company's proposal as a whole is representative of the industry's national productivity trend and is acceptable. The Department also finds it beneficial to utilize the same sample of companies in the TFP study as in the benchmarking study for the reasons discussed in Section II.B.4.e.iii., below.

(D) Capital Cost Specification Method

The Company utilized a capital cost specification method referred to as the one hoss shay method (Exh. NG-MEM-1, at 55). The basic assumption of this method is that an asset provides a constant level of services over the lifetime of the asset (Exh. NG-MEM-1, at 55-56). The one hoss shay method also requires an average service life of all assets in order to estimate the quantity of capital retirements (Exh. NG-MEM-1, at 56). For the Company's TFP study, it used an average service life of 33 years (Exh. NG-MEM-1, at 56). In contrast, the Attorney General deployed the geometric decay and Kahn methods for capital cost specification methods (Exh. AG-MNL-2, at 2). The geometric decay method assumes that the flow of services from investments in a given year declines at a constant rate over time (Exh. AG-MNL-2, at 13). The Attorney General's Kahn method decomposes capital cost into a price and quantity index using a simplified version of cost of service accounting (Exh. AG-MNL-2, at 15, 39). The Department finds that record evidence in the instant proceeding supports the use of the one hoss shay method of capital cost specification. The Department finds that there are significant differences between the capital assets deployed by the electric distribution industry as compared to other industries, such as the telecommunications industry, as well as differences of the rate of obsolescence of capital assets (Exhs. NG-MEM-Rebuttal-1, at 34-35; NG-NWA-Rebuttal-1, at 13). The Department previously accepted the use of the one hoss shay method for an electric distribution company's TFP study. D.P.U. 17-05, at 390. The Department does not accept the Attorney General's argument that the one hoss shay method should be rejected because the Company's capital assets are heterogeneous. Rather, the Department finds that the constant rate of decay of flow of services with the largest decay observed in the first year of a cohort's service life, demonstrated by the geometric decay model, does not reflect the pattern of service flow observed in the electric distribution industry (Exhs. NG-MEM-Rebuttal-1, at 30-31, 33; NG-NWA-Rebuttal-1, at 8, 11-12, 14-15, 16-17). Further, the Department accepts the Company's use of a 33-year average service life in its TFP study, which is consistent with the average service life originally presented in another jurisdiction and verified using FERC Form 1 data (Exhs. NG-MEM-1, at 56-57 n. 49; NG-MEM-Rebuttal-1, at 40).

(E) Conclusion

In the sections above, the Department has reviewed the Company's proposed TFP study, which generates an X factor of -1.72 percent and was used in the benchmarking study to measure the National Grid's cost performance. The Department finds that the TFP study as a whole is acceptable and, therefore, is approved as proposed by the Company.

iii. Consumer Dividend

The consumer dividend is intended to reflect expected future gains in productivity because of the move from cost of service regulation to incentive regulation. D.P.U. 96-50 (Phase I) at 165-166, 280. As a deduction to the PBR adjustment, the consumer dividend is designed to allow ratepayers to share in these aforementioned gains (Exhs. NG-PBRP-1, at 14; NG-LRK-1, at 6, 36). National Grid proposes to apply a consumer dividend of 0.40 percent when inflation exceeds two percent (Exhs. NG-PBRP-1, at 44; NG-LRK-1, at 36). The Company determined the value of 0.40 percent for the consumer dividend by using the results of a cost benchmarking study that compared National Grid's cost performance to its peers (Exhs. NG-LRK-1, at 37-45; NG-LRK-3, at 16-18). While no party objected to the 0.40 percent consumer dividend, the Attorney General objects to the contingency that the consumer dividend is only applied when inflation exceeds two percent (Attorney General Brief at 158-159).

The benchmarking study determined that the Company is an average cost performer in comparison to its national electric distribution company peers (Exhs. NG-LRK-1, at 44-45; NG-LRK-3). The benchmarking study measured National Grid's cost performance using the metrics, unit cost and TFP level, and compared the results calculated for the Company to the national sample (Exhs. NG-LRK-1, at 41; NG-LRK-3, at 3). As measured by unit cost, National Grid is 2.1 percent above the national sample, and for TFP level, is 1.8 percent below the average of the national sample (Exhs. NG-LRK-1, at 42, 45; NG-LRK-3, at 3-4). National Grid states that the Department has approved a consumer dividend of 0.25 for a company that qualified as a superior cost performer under its benchmarking study (Exhs. NG-LRK-1, at 43; NG-LRK-3, at 4, citing D.P.U. 17-05). Further, National Grid states the Department has approved a consumer dividend of 0.40 percent for a company that qualified as an average cost performer under its benchmarking study (Exhs. NG-LRK-1, at 44-45; NG-LRK-3, at 4, citing D.T.E. 05-27). The Department accepts the Company's conclusion that it is currently an average cost performer and approves the consumer dividend of 0.40 percent consistent with our findings for similar cost performers. D.T.E. 05-27, at 393.

As part of its PBR annual filing, the Department directs the Company to provide an update of the benchmarking study that compares its cost performance, as measured by unit cost and TFP, to the sample of 66 nationwide electric distribution companies. The results of an annually updated benchmarking study, using a three-year rolling average of the most recent data, shall be used to set a new consumer dividend component over the PBR term.[26] The updated benchmarking results will reward the Company for becoming more efficient and penalize the Company for becoming less efficient. Beginning with the Company's second PBR filing, after two years of operating under the PBR, and after one year of collecting a PBR adjustment that includes the 0.40 percent consumer dividend, National Grid's consumer dividend component will be updated to reflect its most recent cost performance as measured by unit cost and TFP relative to the national sample of companies. In D.P.U. 17-05, at 395, while there was no benchmarking study presented, the Department approved a consumer dividend of 0.25 percent. The benchmarking study presented in this proceeding determined that NSTAR Electric Company ("NSTAR Electric")[27] is a more cost-efficient utility than

---

[26] An econometric study would be preferable over a benchmarking study to determine whether the Company is improving or declining in its cost performance due to its ability to control for more factors (e.g., system age, population density, territory size) (Tr. 9, at 1268-1270). Nonetheless, no econometric model is included in the record.

[27] In D.P.U. 17-05, at 28-55, the Department approved the corporate consolidation of Western Massachusetts Electric Company with and into NSTAR Electric pursuant to

National Grid, and, therefore, a consumer dividend greater than NSTAR Electric's approved 0.25 percent consumer dividend is warranted for National Grid (Exhs. NG-LRK-1, at 43, 45-46; NG-LRK-3, at 4). Based on these benchmarking study results and on our decisions approving consumer dividends, the Department finds that if National Grid improves its unit cost to 18.0 percent or below the national sample, and its TFP level to 21.0 percent or above the national sample, the Company's cost performance status shall be considered superior and its consumer dividend shall be updated to 0.25 percent in that PBR adjustment filing. If the Company's unit costs were to improve to more than 6.0 percent below the national average, but less than 18.0 percent below the national average, and the TFP level improved to more than 7.0 percent than the national average, but less than 21.0 percent than the national average, the Company would have demonstrated to be an above-average cost performer, and would consequently have the consumer dividend updated to 0.33 percent in that PBR adjustment filing. Conversely, if National Grid's unit costs were to decline to more than 6.0 percent above the national average, and the TFP level were to decline to 7.0 percent or more than the national average, the Company would have demonstrated to be a below-average cost performer and would consequently have the consumer dividend update to 0.48 percent in that PBR adjustment filing. If National Grid's unit costs were to decline to more than 18.0 percent above the national average, and the TFP level were to decline to 21.0 percent or more than the national average, the Company would have demonstrated to be

---

G.L. c. 164, § 96. The legal name of the electric distribution company in Massachusetts is now NSTAR Electric Company.

a poor cost performer and would consequently have the consumer dividend update to 0.55 percent in that PBR adjustment filing. The Department expects that unit cost and TFP measurements will trend together to indicate whether the Company is improving or declining in its cost performance, but if the Company's unit cost and TFP level measurements demonstrate conflicting cost performance categories, the consumer dividend will be set at the difference between the two categories, giving equal weight to unit cost and TFP level.[28]

Regarding the inflation contingency component of the consumer dividend as a mitigation against risk to the Company, the Department directs National Grid to adopt a more nuanced approach. The consumer dividend at certain levels is disproportionate to the annual adjustment. Rather than a strict dichotomy of reducing the consumer dividend to zero percent when inflation is equal to or below two percent, the Department directs the Company to add an intermediate trigger to reduce the applicable consumer dividend by 50 percent when inflation is between one percent and two percent as measured by the annual percentage change in GDP-PI for the four most recent quarterly reports as reported by the U.S. Bureau of Economic Analysis.[29],[30] When inflation is equal to or below one percent, the

28 For instance, if the Company's unit cost is 7.0 percent below the national average, indicating an above-average cost performer, but the TFP level is 5.0 percent above the national average, indicating an average cost performer, the consumer dividend will be set at the midpoint between 0.40 percent and 0.33 percent, or 0.365 percent.

29 Since the Department will allow the dividend to be updated based on performance, this trigger would also apply to the range of potential dividends that the Department established as discussed above (i.e., the lower range of 0.25 would be 0.125).

30 The U.S. Bureau of Economic Analysis is organized within the U.S. Department of Commerce.

applicable consumer dividend will be zero percent in order to mitigate risk to the Company in that given PBR adjustment. Lastly, when inflation is recorded equal to or above two percent, the applicable consumer dividend shall be applied to the PBR adjustment in full.

iv. Exogenous Cost Factor

In D.P.U. 94-158, at 62, the Department recognized that there may be exogenous costs, both positive and negative, that are beyond the control of a company and, because the company is subject to a stay-out provision, they may be appropriate to recover (or return) through the PBR mechanism. The Department has defined exogenous costs as positive or negative cost changes that are beyond a company's control and are not reflected in the GDP-PI. D.P.U. 94-50, at 172-173. These include incremental costs resulting from: (1) changes in tax laws that uniquely affect the relevant industry; (2) accounting changes unique to the relevant industry; and (3) regulatory, judicial, or legislative changes uniquely affecting the industry. D.P.U. 96-50 (Phase I) at 291; D.P.U. 94-50, at 173. The Department has cautioned against expansion of these categories to a broader range. D.P.U. 96-50 (Phase I) at 290-291; D.P.U. 94-158, at 61-62.

National Grid proposes to adopt a definition of exogenous costs that is consistent with the definition adopted by the Department in D.P.U. 94-50 (Exhs. NG-PBRP-1, at 45; NG-LRK-1, at 7). Accordingly, the Department finds that the Company's proposed definition of exogenous costs is appropriate.

To avoid a costly regulatory process over minimal dollars, the Department has found that exogenous cost recovery must be subject to a significance threshold that is noncumulative (i.e., exogenous costs cannot be lumped together into a single total for purposes of determining whether the threshold has been met). D.T.E. 01-56, at 22-23; Boston Edison Company, D.T.E. 99-19, at 26 (1999); D.P.U. 96-50 (Phase I) at 292-293; D.P.U. 94-50, at 173. The significance threshold is determined based on a percentage of the company's total operating revenues, taking into account the term of the PBR insofar as the effects that inflation will have on the threshold in the later years of the PBR. D.T.E. 01-56, at 11-14; Eastern Enterprises/Colonial Gas Company, D.P.U. 98-128, at 57 (1999).

National Grid has proposed an exogenous cost significance threshold of $3.0 million for calendar year 2020, subject to annual adjustments thereafter based on changes in GDP-PI (Exhs. NG-PBRP-1, at 46; NG-LRK-1, at 7). 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. 17-05, at 397; D.T.E. 03-40, at 491; D.T.E. 01-56, at 22-26; D.P.U. 98-128, at 53-56; D.P.U. 96-50 (Phase I) at 293.

National Grid's total test year operating revenues was $2,268,023,815 (Exhs. NG-PBRP-1, at 46; NG-RRP-2 (Rev. 4), Sch. 1, at 2). Consistent with our precedent and the facts of this case, the Department finds that $3.0 million is a reasonable exogenous cost significance threshold for National Grid, which has total operating revenues of

$2,268,023,815 and is implementing a multi-year PBR plan of the overall design approved herein.[31]

In addition, the Company has proposed that the exogenous cost significance threshold be subject to annual adjustments based on changes in GDP-PI as measured by the U.S. Department of Commerce (Exh. NG-LRK-1, at 7).[32] The Department is satisfied that this proposal appropriately takes into account the effects that inflation will have on the threshold in the later years of the PBR. D.P.U. 17-05, at 398; D.T.E. 01-56, at 11-14; D.P.U. 98-128, at 57. Accordingly, we set the Company's threshold for exogenous cost recovery at $3.0 million for each individual event in calendar year 2020, subject to annual adjustments thereafter based on changes in GDP-PI as measured by the U.S. Commerce Department and as used in the PBR formula. Based on the foregoing analysis, the Department approves the Company's proposed exogenous cost factor as a component of the PBR formula.

Exogenous cost recovery requires that a company provide supporting documentation and rationale to the Department for a determination as to the appropriateness of the proposed exogenous cost. D.T.E. 99-19, at 25; D.P.U. 98-128, at 55; Bay State Gas Company, D.T.E. 98-31, at 17-18 (1998). Additionally, any company seeking recovery of an

---

31 Multiplying National Grid's total operating revenues of $2,268,023,815 by a factor of 0.001253 equals $2,841,834.

32 Based on our understanding of the federal government's reporting on GDP-PI, we believe that the U.S. Bureau of Economic Analysis reports on GDP-PI. https://www.bea.gov/data/prices-inflation/gdp-price-index.

exogenous cost bears the burden of demonstrating the propriety of the exogenous cost and that the proposed exogenous cost change has not been incorporated into 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 will not prejudge the qualification of any future events as exogenous costs (e.g., an adverse ruling on a municipal property tax issue, any future transmission formula rate changes mandated by FERC). Instead, at the time it seeks exogenous cost recovery, National Grid must demonstrate that the event meets both the definition and threshold for exogenous costs approved herein.

As a part of the PBR Plan, the Company's proposed Z factor would include exogenous costs, as defined above, with the addition of two items: (1) a storm replenishment factor for recovery of storm costs where the combined balance of the storm fund and any costs associated with storm events over $30.0 million exceeds $75.0 million; and (2) the inclusion of the Patient Protection and Affordable Care Act's excise tax on high-cost employer medical plans (Exh. NG-PBRP-1, at 45). As discussed in further detail in in Section XII.D., below, the Department approves the Company's proposal to seek cost recovery through the exogenous cost provision of the PBR Plan (pending a prudence review) provided that the combined balance of the storm fund and any costs associated with storm events over $30.0 million exceed $75.0 million.

Regarding the inclusion of the excise tax on high-cost employer medical plans, the Department is not convinced at this time that it is appropriate to include this as an additional component to the Z factor. The Company states that this new excise tax on high-cost employer medical plans is not scheduled to take effect until 2022 (Exh. NG-PBRP-1, at 46). Further, the Company's forecast for the impact of the tax is $560,000, which is significantly below the cost threshold of $3.0 million (Exh. DPU-NG 31-13). Lastly, the Patient Protection and Affordable Care Act's excise tax on employer medical plans is not unique to the electric distribution industry (RR-DPU-23). For these reasons, the Department rejects the Company's proposal of including this excise tax for recovery through the Z factor.

v. Earnings Sharing Mechanism

The Department has found that earnings sharing mechanisms may be integral components of incentive regulation plans. D.P.U. 94-50, at 197 n.116. Specifically, the Department has found that earnings sharing mechanisms 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.

The Company proposes to implement an asymmetrical earnings sharing mechanism with a deadband of 200 basis points (Exhs. NG-PBRP-1, at 46; NG-MEM-1, at 7). Under the Company's proposal, earnings would be shared with ratepayers and shareholders on a 50/50 basis when the calculated distribution ROE exceeds the ROE authorized in this proceeding by 200 basis points (Exh. NG-PBRP-1, at 46-47). When the actual ROE exceeds 300 basis points above the authorized ROE, all earnings above 300 basis points would be shared 90 percent with customers and 10 percent with the Company (Exh. NG-PBRP-1, at 47).

The Attorney General opposes the Company's design of the earnings sharing mechanism (Attorney General Brief at 160). Specifically, the Attorney General contests the split of earnings sharing and the two-tiers of the mechanism (Attorney General Brief at 160). The Attorney General maintains that the Department has previously determined that an earnings sharing mechanism should largely benefit ratepayers and should not be tiered to avoid concerns regarding incentives at the margin of the bands (Attorney General Brief at 160, citing D.P.U. 17-05, at 400-401). Accordingly, the Attorney General argues that the Department should approve an earnings sharing mechanism where earnings that exceed the deadband would be split 75 percent with ratepayers and 25 percent with shareholders (Attorney General Brief at 160).

An earnings sharing mechanism offers an important protection for ratepayers in the event that expenses increase at a rate much lower than the revenue increases generated by the PBR. D.P.U. 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 earnings sharing mechanism as part of the PBR mechanism adopted in this case. As discussed below, the Department finds that certain modifications to the Company's proposed earnings sharing mechanism are necessary to appropriately balance the risks to shareholders and ratepayers under the PBR.

As noted above, the Company proposes to adopt a deadband of 200 basis points (Exhs. NG-PBRP-1, at 46; NG-MEM-1, at 7). The Department has approved earnings sharing mechanisms with deadbands of 200 basis points or greater. 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. Here, with the changes to the tiered structure and earnings percentages discussed below, the Department finds that a 200-basis point deadband is both consistent with Department treatment of such mechanisms and is reasonable to apply in this instance.

The Department finds that a 200-basis point deadband will provide the Company with a strong incentive to pursue savings. To appropriately balance shareholder and ratepayer risk under the PBR as designed, the Department finds that the benefits of any earnings above the deadband must inure largely to ratepayers. Accordingly, we find that a mechanism that shares earnings with ratepayers and shareholders on a 75/25 basis above the 200-basis point deadband is appropriate in this case (i.e., 75 percent to ratepayers and 25 percent to shareholders). This ratio will provide National Grid an adequate incentive to pursue savings and also will protect ratepayers from an unforeseen financial windfall for the Company as a result of the implementation of the PBR.

Finally, the Department finds that the Company did not appropriately address the concern that the Department identified in D.P.U. 17-05 that a tiered deadband structure can create perverse cost containment incentives at the margin that can encourage misreporting or changes in spending. D.P.U. 17-05, at 401. The Department finds that a non-tiered earnings sharing mechanism will resolve any concerns regarding incentives at the margin and achieve the goals of simplicity and administrative efficiency.

In conclusion, the Department finds that the Company's PBR shall include an earnings sharing mechanism that sets a 200 basis points deadband above the Company's authorized

ROE. If National Grid's earned distribution ROE falls within or below the deadband, there will be no sharing. If the Company's earned distribution ROE exceeds the deadband, the earnings above the deadband will be shared 75 percent with ratepayers and 25 percent with shareholders.

vi. PBR Adjusted Revenues

The Company's PBR adjustment is designed to cumulatively adjust the distribution revenue approved for recovery in the Company's most recent base distribution rate case and for the transition of the CIRM (Exh. NG-HSG-12, Proposed M.D.P.U. No. 1400 (Bates Stamp 284)). The Attorney General argues that any costs formerly recovered from reconciling mechanisms that are proposed to be rolled into rate base should be removed from the PBR adjustment (Attorney General Brief at 160-161). Specifically, the Attorney General objects to the PBR mechanism applying to cumulative capital investment made in relation to the Company's CIRM and smart grid pilot program through the end of the test year and the solar phase II cumulative capital investments through September 30, 2018. The Department discusses the determination of including the smart grid pilot program costs in base distribution rates, in Section VII.C., below. The Department discusses the transition of the CIRM in Section IV. D., below. Regarding the inclusion of CIRM costs through the test year in base revenues adjusted by the PBR mechanism, the Department finds that this ratemaking treatment is appropriate. The Department discusses its decision on post-test-year solar phase II costs proposed for inclusion in base distribution rates in Section VI.C., below.

Regarding solar facility costs approved for inclusion in base distribution rates, the Department finds that it is appropriate to remove these costs from the PBR mechanism adjustment calculation and maintain the revenues associated with these solar facilities at test-year levels until the Company's next base distribution rate case. Our conclusion is based on three factors. First, solar facility costs represent power generation costs, rather than distribution costs. The TFP studies presented in this case were designed to apportion costs so that they excluded power generation costs; therefore, the X factor does not account for these types of assets (Exhs. NG-MEM-1, at 55-61; AG-MNL-2, at 34-35). Second, the costs associated with solar facility projects fall outside the Company's regular operations of safely and reliably delivering electricity to customers. Accordingly, the Company is not obligated to replace these assets when they retire, but it could continue to collect a revenue target that increases annually by the PBR mechanism. Third, the ongoing costs associated with Company-owned solar generation facilities that are not included in base distribution rates, including taxes and depreciation expenses, will be recovered by the Company through the solar cost adjustment provision reconciling mechanism (Exh. NG-HSG-12, Proposed M.D.P.U. No. 1388 (Bates Stamp 170)). The Department has found it suitable to modify PBR plans or simplified incentive plans to exclude adjustments for certain types of costs. NSTAR Electric Company, D.P.U. 18-101, Exhs. NSTAR-DPH at 18; NSTAR-DPH-1, at 1 (certain storm costs excluded from PBR adjustment); D.P.U. 17-05, at 392 (removal of certain grid modernization investments); NSTAR Electric Company/NSTAR Gas Company, D.P.U. 08-56/D.P.U. 09-96, at 18-19 (2010) (removal of certain pension/post-retirement benefits other than pension ("PBOP") costs). The Department, therefore, directs the Company to revise the definition of PBR revenue to exclude the costs of its solar facility projects completed and in service prior to the end of the test year, which were approved in this proceeding or in a previous proceeding.

5. Conclusion

In the sections above, the Department has reviewed the Company's PBR proposal and has found that, as approved, it is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. In addition, the Department has found that the proposed PBR plan, as approved, will provide National Grid with greater incentives to reduce costs than currently exist and should result in benefits to customers that are greater than would be present under current regulation. Further, the Department has found that the proposed PBR Plan, as approved, better satisfies our public policy goals and statutory obligations, including promotion of the Commonwealth's clean energy goals and mandates.

With the modifications to the PBR formula required herein, the Department finds that the PBR 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 National Grid's proposed PBR, subject to the modifications required herein. National Grid, in its compliance filing, is directed to submit a revised PBR provision tariff consistent with the findings in this Order (Exh. NG-HSG-12, Proposed M.D.P.U. 1400 (Bates Stamp 284-302)).

Further, National Grid shall submit an annual PBR adjustment filing, including all information and supporting schedules necessary for the Department to review the proposed PBR adjustment for the subsequent rate year. Such information shall include the results and supporting calculations of the PBR adjustment factor formula, descriptions and accounting of any exogenous events, an updated benchmarking study that compares the Company's three-year average unit cost and TFP level to the three-year national sample average, and an earnings sharing credit calculation for the year, two years prior to the rate adjustment. In addition, National Grid shall file revised summary rate tables reflecting the impact of applying the base distribution rate changes provided in the PBR adjustment filing. National Grid is directed to submit its annual PBR adjustment filing on or before June 15 each year, commencing in 2020 and continuing for the five-year term of the PBR. Consistent with our findings above, the PBR shall continue in effect for a total of five consecutive years starting October 1, 2019, with the last adjustment taking effect on October 1, 2023 and expiring on September 30, 2024.

C. Performance Incentive Mechanism and Scorecard Metrics

1. Introduction

The Company proposed PIMs as an element of its PBR Plan (Exh. NG-PBRP-1, at 9).[33] The Company states that its proposed PIMs are intended as motivation to achieve policy goals set forth by the Department and the Commonwealth and to allow stakeholders to monitor the Company's progress during the five-year term of the PBR Plan (Exh. NG-PBRP-1, at 9). The Company states that its PBR Plan will incentivize effective innovation to achieve additional cost savings in the Company's traditional business activities and would reward the Company for exceptional performance in targeted areas (Exh. NG-PBRP-1, at 13). These targeted performance areas include the policies of the Department and the Commonwealth related to peak reduction,[34] transportation electrification, and customer ease (Exh. NG-PBRP-1, at 13, 15). The four specific PIMs proposed by the Company are (1) Customer Ease, (2) Peak Reduction, (3) Electric Vehicle ("EV") Adoption, and (4) EV Supply Equipment ("EVSE") Cost Containment (Exh. NG-PBRP-1, Table PBRP-1, at 54).

---

33 The Company recognized the Department's directives to NSTAR Electric that metrics under a PBR plan should be broad performance metrics in three categories that are tied to the goals of the PBR plan and consistent with the Department's regulatory objectives: (1) improvements to customer service and engagement; (2) reductions in system peak; and (3) strategic planning for climate adaptation (Exh. NG-PBRP-1, at 52 citing D.P.U. 17-05, at 407).

34 For this purpose, peak refers to the highest point of customer consumption of electricity on the Company's distribution system, usually measured for a half-hour or hour period.

The Company also proposed three scorecard metrics, which it states are intended to make the Company's performance more transparent to customers, the Department, and stakeholders (Exh. NG-PBRP-1, at 95). The three scorecard metrics proposed are: (1) company greenhouse gas ("GHG") emissions reductions; (2) customer engagement; and (3) DER customer experience (Exh. NG-PBRP-1, at 96).

2. Company Proposal

a. Customer Ease

The Customer Ease PIM is designed to measure the simplicity of how customers interact and do business with the Company, including billing, field services, website, call center, and products and service offerings (Exh. NG-PBRP-1, at 85). This Customer Ease PIM was based on a question in the Company's brand, image, and relationship survey that is administered to residential customers requesting them to rate the Company on "[h]ow easy it is to do business with National Grid" (Exh. NG-PBRP-1, at 85-86). The survey uses a one to ten scale, where one is "not at all easy" and ten is "very easy" (Exh. NG-PBRP-1, at 86). The customer ease score shows the percent of customers who answer eight, nine, or ten, or the "Top 3 Box" (Exh. NG-PBRP-1, at 86). The surveys are administered each month to approximately 100 random residential electric customers in Massachusetts online and are analyzed by the independent market research firm, Market Probe, Inc. (Exh. NG-PBRP-1, at 86). The survey has separate quotas for the Boston region and Central/Western MA so the data is weighted based on the number of customers in each of those regions (Exh. NG-PBRP-1, at 86).

The Company established a proposed customer ease baseline of 62.4 percent using the survey results data from the twelve months, October 2017 through September 2018, and proposed targets that are set to improve the customer ease score to a level that is above the Company's historic levels of performance (Exh. NG-PBRP-1, at 86-87). For example, the minimum target for 2020 represents a one-percentage point increase in customer ease above the Company's historic baseline, whereas the maximum target for 2024 represents a nine-percentage point increase above the baseline (Exh. NG-PBRP-1, at 87). The targets were developed based on the Company's historic performance and also took into account the key drivers that the Company can influence, as well as the new and different investments that National Grid intends to make to improve customer ease (Exh. NG-PBRP-1, at 87). The customer ease metric has been tracked by the Company, internally, since 2015 (Exh. NG-PBRP-1, at 91).

Market Probe, Inc., identified the Company's key drivers of customer ease to be (1) providing responsive customer service and (2) making customers feel valued (Exh. NG-PBRP-1, at 87-88). The Company plans to undertake commitments to improve customer ease through initiatives, such as new interactive voice response system launch, expansion of online chat function, implementation of personalization tool, Company website optimized on any device, and web reliability and security improvements including online ability to transact 24 hours a day/seven days a week and a simplified login experience (Exh. NG-PBRP-1, at 88-89).

The Company proposed that, in its annual June 15 PBR Plan filing, it will report its performance on customer ease for the prior calendar year by calculating incremental percentage points above the Company's historic baseline by averaging the measurements of each of the twelve months of the calendar year (Exh. NG-PBRP-1, at 90). For the Company to start earning the incentive for the Customer Ease PIM, the Company, at a minimum, must demonstrate an improvement in performance by at least one percentage point over the customer ease baseline of 62.4 percent (Exh. NG-PBRP-1, at 90). The incentives would increase incrementally over the five-year period, with the minimum incentive starting at $0.3 million and increasing by $0.15 million each year, the target incentive starting at $0.6 million and increasing by $0.3 million each year, and the maximum target starting at $0.9 million and increasing each year by $0.45 million until 2024 (Exh. NG-PBRP-1, at 90). If the Company surpasses the maximum target in a specific year, it would earn the maximum incentive, which would act as a cap for that year (Exh. NG-PBRP-1, at 91).

b. <u>Peak Reduction</u>

National Grid proposed a PIM that focuses on its distribution system peak (Exh. NG-PBRP-1, at 59).[35] The Company stated that the benefits to customers from reducing National Grid's distribution system peak include: (1) reductions in energy cost from elimination of peak energy demand or shifting demand to other lower-cost hours, energy market price suppression due to lower kWh consumption during peak times, and

---

35 In its filing, for the purposes of peak demand reduction, National Grid refers to peak demand reductions solely in the "Mass. Electric distribution system," and not Nantucket Electric (Exh. NG-PBRP-1, at 63 n16).

savings from reductions in ancillary market[36] price reductions;[37] (2) reductions in ISO New England Inc. ("ISO-NE")[38] forward capacity market costs due to reduction in the installed capacity requirement, and price suppression benefits through reductions in this capacity demand;[39] and (3) reductions in transmission charges billed to the Company's customers relative to what they otherwise might have been (Exh. NG-PBRP-1, at 59-60).

The Peak Reduction PIM is intended to measure the reduction in demand of the Company's distribution system peak through various Company-influenced and Company-owned measures during the top five peak events of the summer for a maximum of three hours at a time (Exh. NG-PBRP-1, at 62-63).[40] The reductions will be measured on a

---

36 Under the ISO-NE markets, ancillary services are a group of market services, such as contingency reserves and frequency regulation, that ensure reliability of the power system at all times and especially during periods of heavy demand or system emergencies. Like electricity, ancillary services are bought and sold through wholesale markets.

37 Estimated savings reductions in ancillary market price reductions are according to the State of Charge: Massachusetts Energy Storage Initiative Study, published July 2016, Department of Energy Resources and Massachusetts Clean Energy Center (Exh. NG-PBRP-1, at 60 n12).

38 ISO-NE is a not-for-profit, private corporation that serves as the regional transmission organization for New England. ISO-NE operates the New England bulk power system and administers New England's wholesale electricity market. Investigation Into Need For Additional Capacity In NEMA/Boston, D.P.U. 12-77, at 1 n.1 (2013).

39 The price suppression benefits through reductions in this capacity demand were estimated by the Avoided Energy Supply Components in New England: 2018 Report, published March 30, 2018, The AESC Study Group by Synapse Energy Economics, Inc. (Exh. NG-PBRP-1, at 60 n.13).

40 Nantucket Electric intends to address its summer system by the deployment of a new 10-MW generation plant and a 48-MWh energy storage battery. The project is

unit-specific basis of megawatt ("MW") contribution during the time of system peak (Exh. NG-PBRP-1, at 63). The proposed peak demand reduction measures include Company-owned solar photovoltaic ("PV") and energy storage, customer-owned front-of-the-meter and behind-the-meter solar PV and energy storage, volt/var optimization,[41] and standard technology upgrades (Exh. NG-PBRP-1, at 63).

The Company proposed to establish a baseline for the Peak Reduction PIM using a bottom-up approach that estimates the average peak reduction contribution (in MW) of resources expected to be installed or connected, based on estimated and historic performance contributions, whereby the estimated contributions from all the measures are summed to determine the aggregate contribution to the Company's distribution system peak events (Exh. NG-PBRP-1, at 63-64). This baseline was established by: (1) estimating the total MW of new resources to be interconnected in 2019 based on current and historical queue data and customer trends; (2) developing a forecast for the minimum, target, and maximum levels of performance expected in connecting resources in future years, as 100 percent, 150 percent, and 200 percent of the four-year average annual growth rate; and (3) developing a threshold level of annual incremental peak reduction based on the expected contribution of

---

expected to defer the need for investment in a third undersea cable for 15-20 years; therefore, National Grid will focus on the MECo peak reduction (Exh. NG-PBRP-1, at 63 n.16).

41 Volt/var optimization is an advanced function that determines the best set of control functions for all voltage regulating devices and var control devices. Var refers to volt-ampere reactive, which is a unit of measurement of reactive power. Reactive power exists in an AC current when the current and voltage are not in phase.

various resources at or above the threshold that the Company would be able to earn an incentive up to a maximum level of incentive (Exh. NG-PBRP-1, at 64). During the course of the proceeding, the Company provided a revised base interconnection volume forecast to obtain a new peak reduction minimum threshold, target, and maximum levels with associated new benefit levels and incentive levels (Tr. 8, at 1187-1188; RR-DPU-24). The new forecast levels are 150 percent, 300 percent, and 450 percent of the four-year average annual growth rate (RR-DPU-24; RR-DPU-25, at 3).

National Grid proposed five categories of Company-influenced and Company-owned measures to reduce the system peak: (1) solar PV; (2) energy storage; (3) volt/var optimization; (4) standard technology upgrades; and (5) other measures (Exh. NG-PBRP-1, at 65-70).[42] For solar PV, the Company forecasts incremental annual installations (in MW) of distributed solar PV based on historical amounts and rate of PV interconnection completions and the current queue of interconnection applications (Exh. NG-PBRP-1, at 65). The Company proposed that the estimated annual installed capacity (in MW) of solar capacity will be multiplied by the Company's solar coincidence factor based on expected solar output at the 5:00 pm peak hour (21 percent), as the median hour of expected system peak events (Exh. NG-PBRP-1, at 66). The Company stated that the peak reduction forecast from solar PV system increases over time in relation to the increased incremental amount of solar PV systems connected each year (Exh. NG-PBRP-1, at 66). For energy storage, the Company

42 In a further revised filing, the Company removed standard technology upgrades from peak demand reduction MW contributions (Exh. NG-PBRP-2 (Rev. 2), Att. 1, at 7).

examined the total MW's of energy storage currently being proposed for interconnection in its service territory in order to estimate the amount of energy storage that will be connected to the Company's distribution system during the PBR Plan term (Exh. NG-PBRP-1, at 67). The Company applied the ratio of alternating current ("AC") connected and direct current connected energy storage capacity in the queue to the amounts of AC capacity that the Company projects it would connect at a minimum level (Exh. NG-PBRP-1, at 67). Due to lack of historical information or evaluation reports for regions similar to the service area and rate structure of the Company, the Company assumes an 80-percent coincidence factor (Exh. NG-PBRP-1, at 68). The Company expected that residential energy storage systems will mainly serve onsite load, allow for resiliency and demand charge management, and will have a lower coincidence factor with National Grid's system peak (Exh. NG-PBRP-1, at 68-69). Thus, the Company assumes of a 50-percent coincident factor for the storage category but will review that assumption with real data and adjust during the mid-point PBR Plan review (Exh. NG-PBRP-1, at 69). For volt/var optimization, the benefits and investments are captured within the Company's grid modernization plan, and the respective benefits will accrue in calendar year 2021 after the assets are installed within the second year of the PBR Plan (Exh. NG-PBRP-1, at 69). The Company made reduction assumptions based on the experience of its affiliate Narragansett Electric Company with its volt/var pilot in Rhode Island (Exh. NG-PBRP-1, at 69). For other measures, the Company may propose time-varying rates and look for opportunities to partner with third parties to procure services to reduce demand, or the Company may encourage customers to obtain devices that enable such service (Exh. NG-PBRP-1, at 70).

Through these measures, the Company plans to drive peak reduction performance by delivering solar PV projects in the interconnection queue in a higher volume than the projected baseline rate of interconnection (Exh. NG-PBRP-1, at 71). In the medium term, the Company plans to look for new procurement programs and partnerships with third parties (Exh. NG-PBRP-1, at 70-71). The Company indicated that the solar Massachusetts renewable target provision, in addition to the clean peak standard operating requirements by DOER, will provide additional support and more effective deployment of energy storage (Exh. NG-PBRP-1, at 71-72, citing Solar Massachusetts Renewal Target Provision, D.P.U. 17-140).

The Company proposed minimum, target, and maximum peak reduction levels and respective incentives for achieving each peak reduction goal (Exh. NG-PBRP-1, at 74). The maximum incentive level proposed is scaled at 200 percent of the minimum incentive level, with each percentage increase in peak resulting in a percentage increase in the minimum incentive (Exh. NG-PBRP-1, at 74). The Company proposed that in order for the Peak Reduction PIM to be measured each year, the top five peak events will be determined at the end of each calendar year by identifying the five top hours of system demand that occurred on separate days (Exh. NG-PBRP-1, at 75). The impact from peak reduction of contributing measures will be calculated based on their actual performance if metered data is available or otherwise by using assumptions (Exh. NG-PBRP-1, at 75). The Company will take a direct contribution per hour over each peak event with a maximum of three hours at a time, then will average the contributions from all resources over all 15 hours (top five peak events * three hours) (Exh. NG-PBRP-1, at 75). The average of the 15 hours will be compared against the incremental peak reduction targets (Exh. NG-PBRP-1, at 76). For an average incremental amount of peak reduction at or above the minimum level, the Company will calculate the earned incentive and report on its progress in earning the incentive as part of its annual PBR Plan filing (Exh. NG-PBRP-1, at 76).

c. Transportation Electrification

The Company proposed two transportation electrification PIMs that would be awarded based on the Company's performance in delivering its proposed Phase II EV Program (Exh. NG-PBRP-1, at 77).[43] EV Adoption, the first transportation electrification PIM, would reward the Company based on higher incremental EV adoption in the Company's service area (Exh. NG-PBRP-1, at 77). Phase II EV Program Cost Containment, the second transportation electrification PIM, would reward the Company for cost-efficiency in its delivery of the EV charging infrastructure portion of the program (Exh. NG-PBRP-1, at 77). The metric to measure the EV Adoption PIM would be the incremental light duty vehicle adoption that would potentially result from the Company's proposed Phase II EV Program (Exh. NG-PBRP-1, at 77). The Company established targets set to represent the incremental vehicles adopted annually above the Company forecast level and relative to the

43 The Company's proposed Phase II EV Program is a five-year program that it states is designed to support the projected EV charging infrastructure needed in the Company's service territory by the end of 2024 (Exh. NG-PBRP-1, at 82).

Commonwealth's zero emissions vehicles ("ZEV") goals (Exh. NG-PBRP-1, at 77-78). The Company proposed to establish a baseline through a forecast that was developed by applying a growth rate in EV sales for 2020 through 2024 derived from the U.S. Energy Information Administration's Annual Energy Outlook 2018 projection of EV sales in New England, to historic data on EV registrations in Massachusetts in the Company's service territory from IHS Markit Ltd. ("IHS Markit"), which, among services, provides automotive market research and data (Exhs. NG-PBRP-1, at 78; DPU-NG 24-11). The proposed EV Adoption targets and potential incentives reflect a 40-percent, 100-percent, and 160-percent improvement over National Grid's projected incremental annual EV adoption levels, which correspond to the minimum, target, and maximum levels, respectively (Exh. NG-PBRP-1, at 79).

To measure the performance of the EV Adoption PIM, the Company will calculate for each calendar year incremental EV adoption vehicles above Company forecasts based on the IHS Markit data (Exh. NG-PBRP-1, at 79). The Company proposed that the incentive amount be calculated as follows: for any number above the minimum target up to the maximum target, the incentive is calculated by multiplying the ratio of the number of incremental EVs registered and the maximum target, multiplied by the maximum earning opportunity for the relevant calendar year (Exh. NG-PBRP-1, at 79-80).

The Company's proposed EVSE Cost Containment PIM aims to reward the Company for delivering the target number of EV charging ports in the Phase II EV Program below the total program budget excluding the Program's R&D Plan (Exh. NG-PBRP-1, at 80-81). The

Company is eligible for the incentive, if it achieves 75 percent of the target number of ports at or below 70 percent of the aggregate capital and O&M budget levels, as well as meeting a threshold of 33 percent of the target number of ports for each site category (Exh. NG-PBRP-1, at 81). If the Company achieves this threshold requirement for all savings of the application portion of the program budget, the Company would be eligible to retain ten percent of those savings multiplied by the ratio of actual EV charging ports installed to the program goal, up to a maximum incentive of $2 million (Exh. NG-PBRP-1, at 81). The program budget would be scaled to account for over-delivery of EV charging port targets (Exh. NG-PBRP-1, at 81). The Company will report its progress toward the incentive thresholds for this metric as part of its annual PIMs filing (Exh. NG-PBRP-1, at 81).

d. Scorecard Metrics

The Company states it developed scorecard metrics to make the Company's performance more transparent to customers, the Department, and other stakeholders (Exh. NG-PBRP-1, at 95). Unlike PIMs, the scorecard metrics do not include incentives for achievement of specified targets and will not have any bearing on the Company's revenue requirement (Exh. NG-PBRP-1, at 95). The Company's proposed scorecard metrics are (1) Company GHG emissions reductions, (2) customer engagement, and (3) DER customer experience (Exh. NG-PBRP-1, at 96). The Company will report on all scorecards metrics as part of the annual PIMs reporting in the June 15 PBR filings each year from 2021 through 2025 (Exh. NG-PBRP-1, at 103).

The proposed metric for Company GHG emissions reductions measures the avoided metric tonnes of carbon dioxide emissions or equivalent from the Company's three primary sources within its electric operations: (1) electric transmission and distribution operations; (2) property; and (3) transportation fleet (Exh. NG-PBRP-1, at 96). The Company proposed to reduce the annual GHG emissions of its electric operations by ten percent, or 4,449 metric tonnes carbon dioxide emissions or equivalent cumulative, by 2024 from a 2017 baseline (Exh. NG-PBRP-1, at 97). The Company developed this target by combining two longer-term corporate targets that apply to all National Grid USA operations, 70-percent reduction in GHG emissions by 2030 from a 1990 baseline, and an 80-percent reduction in GHG emissions by 2050 from a 1990 baseline (Exh. NG-PBRP-1, at 97).

The scorecard metric proposed for customer engagement includes four separate measures: (1) customer adoption of digital bill payment; (2) web user experience index; (3) first contact resolution; and (4) average speed to answer telephone inquiry (Exh. NG-PBRP-1, at 99-100). The baselines for each measure were established by taking the average of the twelve most recent months of data (Exh. NG-PBRP-1, at 100). The Company states that the purpose of this metric is to demonstrate how the Company is progressing and improving customer engagement over the term of the PBR Plan (Exh. NG-PBRP-1, at 101).

The proposed DER customer experience scorecard metric also is comprised of four separate measures: (1) customer adoption rate of the e-signature feature on the DER customer portal ("nCAP portal"); (2) user adoption rate of e-payment feature on the nCAP portal; (3) average number of days to answer a customer inquiry; and (4) conversion rate of project applications received to authority to interconnect issued (Exh. NG-PBRP-1, at 101-102). The purpose of this metric is to track and gauge DER customer engagement and satisfaction levels (Exh. NG-PBRP-1, at 102). The Company has been collecting data from the nCAP portal used in Massachusetts since May 2018 (Exh. NG-PBRP-1, at 102). The Company proposed to establish a one-year baseline using nCAP data from May 2018 to April 2019 (Exh. NG-PBRP-1, at 102).

3. Position of the Parties

a. Attorney General

The Attorney General contends that the Company's proposed PIMs are a lopsided, asymmetrical request to garner additional revenues and earnings beyond the substantial revenue increases tied to the PBR mechanism formula (Attorney General Brief at 167). The Attorney General takes issue with the Company's claim that the proposed PIM targets of reducing system peak load, improving customer service, and preparing the distribution system for future transportation electrification are extraneous or supplemental/optional commitments beyond the Company's core service obligations (Attorney General Brief at 168). The Attorney General contends that the Company's claim is misplaced because customers already pay to receive customer service and reductions in system peak load are undertaken primarily to attain reliable, resilient, and least-cost electricity distribution (Attorney General Brief at 168). The Attorney General also argues that the Company cannot claim that its distribution obligations will now include two-way power flows; greater system resilience; ameliorating environmental impacts; and affording customers new technologies and customer engagement so as to require a PBR, and, at the same time, claim that it deserves additional financial incentives if it actually undertakes and achieves those measures (Attorney General Brief at 169).

Additionally, the Attorney General disagrees with the Company that PIMs emulate a competitive marketplace (Attorney General Brief at 169). The Attorney General maintains that the costs of initiatives such as promoting and interconnecting solar PV, deploying battery energy storage and volt/var optimization, and advancing EV charging infrastructure are fully funded by ratepayers through separate reconciling surcharges that are outside of base distribution rates (Attorney General Brief at 169). Therefore, the Attorney General contends that costs of those initiatives do not impose risk on the Company's shareholders (Attorney General Brief at 169). The Attorney General asserts that the Company should not receive additional revenue on top of revenue increases included in the PBR mechanism (Attorney General Brief at 192).

The Attorney General argues that the Department should reject the Company's two proposed EV PIMs (Attorney General Brief at 192). The Attorney General contends that the EV PIMs are not properly designed and that the financial risk from this ineffective design would fall on ratepayers and not shareholders (Attorney General Brief at 192; Attorney General Reply Brief at 60-61). In addition, the Attorney General argues that the EV Adoption PIM suffers from the following design problems: (1) it is a reward-only incentive, with no risk to shareholders for shortfall of projections, and it is linked to an outcome over which the Company's influence is limited and difficult to verify; (2) the incentive level is not appropriately scaled to match the Company's actual activity within the broader EV market; and (3) the Company already would be earning a rate of return on deployment of EV infrastructure (Attorney General Brief at 192, citing Exh. AG-EAB at 38).

With regard to the EVSE Cost Containment PIM, the Attorney General argues that using projected costs in designing this PIM renders such costs as speculative given that no results from the Phase I EV Program have been formally collected or reported (Attorney General Brief at 192-193). The Attorney General recommends that, instead of approving the EV PIMs, the Company should begin tracking metrics for future EV PIMs (Attorney General Brief at 193).

The Attorney General argues that the Company's reliance upon the Department's decision in D.P.U. 94-158 for the PIMs is inapt (Attorney General Brief at 170). The Attorney General states that in 1995 when that decision was rendered, a distribution company's involvement in environmental compliance and demand-side management initiatives were limited and attenuated because there were no statutory mandates for energy efficiency or for peak load reduction (Attorney General Reply Brief at 170). Additionally, the Attorney General states that, in 1995, the Department had not yet adopted revenue decoupling as a means of aligning shareholder interests with the environmental objectives to reduce electricity consumption (Attorney General Reply Brief at 171).

The Attorney General concludes that the Department should reject the proposed PIMs because they would result in ratepayers paying twice for the same desired performance, once by funding the broad-based PBR annual revenue increases and again through the PIMs (Attorney General Reply Brief at 61). The Attorney General does not substantively address National Grid's proposed scorecard metrics on brief (Attorney General Brief at 167 n.90).

b. Acadia Center

Acadia Center argues that the Department should reject the PIMs as incentives but should adopt the following scorecard metrics: peak reduction; customer ease; the Company's three proposed scorecard metrics; and the seven other scorecard metrics proposed by intervenors (Acadia Center Brief at 3, 11). Acadia Center asserts that National Grid's proposed PIMs have three primary design flaws: (1) they reward the Company for events outside of its control; (2) the correlation between the incentive earned and benefits delivered is inconsistent between PIMs and across years; and (3) PIMs should include a symmetrical downside, unless there is reason to design them differently (Acadia Center Brief at 12).

Acadia Center recommends that the Department reject the proposed EV PIMs (Acadia Center Brief at 11). For example, Acadia Center argues that the EV Adoption PIM design rewards the Company for an event that is linked to a broader market trend for which National Grid's influence is limited and difficult to verify (Acadia Center Brief at 12). In addition, Acadia Center alleges that the Company already has existing incentives for deployment of EV infrastructure (e.g., rate recovery of capital costs) and, therefore, National Grid has no clear disincentive for advancing the EV market (Acadia Center Brief at 12). Acadia Center contends that unlike the Phase I EV Program, in the instant proceeding the Company is requesting both EV PIMs and a rate of return, whereas in the Phase I EV

Program the Department approved a PIM in lieu of a rate of return (Acadia Center Brief at 12).

Acadia Center contends that the proposed PIMs should be adopted as scorecard metrics because they establish baselines of performance that allow stakeholders and the Department to monitor performance and create transparency in important areas (Acadia Center Brief at 13). Acadia Center asserts that scorecards metrics are a low-cost and low-risk option for monitoring utility performance that can provide significant value to all stakeholders and serve to inform the design of future PIMs (Acadia Center Brief at 13). Acadia Center also maintains that the Company should be required to consider non-wires alternatives (Acadia Center Brief at 6). Acadia Center concludes that the Department should decline to adopt the proposed PIMs as incentives (Acadia Center Brief at 12).

c. American Petroleum

API argues that the EV PIMs are inappropriate and should be rejected by the Department (API Brief at 29). API alleges that the proposed PIMs are not in line with Department precedent and are based on subjective rather than inputs (API Brief at 29). In addition, API argues that the EV Adoption PIM is based on outcomes that are outside of the Company's control (API Brief at 29).

d. Clean Energy Parties

Clean Energy Parties argue that it is inappropriate to approve a PIM that rewards the Company for outcomes beyond its control. Specifically, Clean Energy Parties assert that the proposed EV Adoption PIM is arbitrary given that the Company's Phase II EV Program is not the only factor that influences EV adoption (Clean Energy Parties Brief at 24-25; Clean Energy Parties Reply Brief at 21-22). Clean Energy Parties further argue that the mere measurability of the EV Adoption PIM does not make it an appropriate PIM (Clean Energy Parties Reply Brief at 22). As an alternative, Clean Energy Parties recommend a new PIM using U.S. Energy Information Administration data to quantify fuel savings provided by EVs (Clean Energy Parties Brief at 24-25; Clean Energy Parties Reply Brief at 21-22). Clean Energy Parties argue that this PIM is designed based on a fixed target of EV charging ports supported by the Phase II EV Program (Clean Energy Parties Reply Brief at 22). Clean Energy Parties allege that basing an EV PIM on fuel savings is optimal since fuel cost savings are the biggest motivator of EV adoption (Clean Energy Parties Brief at 25; Clean Energy Parties Reply Brief at 23). Lastly, Clean Energy Parties argue that if the EV Adoption PIM is approved, the trigger levels should be modified to be consistent with the number of EVs estimated to be necessary to meet Global Warming Solutions Act goals in the Company's service territory (Clean Energy Parties Reply Brief at 23-24).

e. CLF

CLF argues that the proposed EV PIMs are not in the public interest (CLF Brief at 29). CLF argues that the proposed EV PIMs do not expose the Company to any meaningful risk of shortfalls (CLF Brief at 27). Specifically, CLF argues that the EV Adoption PIM is too dependent on outcomes outside of the Company's control and the EVSE Cost Containment PIM is an incentive for cost cutting that would undermine the efficacy of the proposed Phase II EV Program (CLF Brief at 27).

With regard to the EV Adoption PIM, CLF maintains that it is not sufficiently ambitious since it is based on low benchmarks for EVSE infrastructure needs required to catalyze the EV market (CLF Brief at 28). Moreover, CLF contends that there are numerous factors outside of the Company's control that influence EV adoption (e.g., EV prices, EV dealer marketing, federal and state incentives, Volkswagen settlement funds) (CLF Brief at 28). CLF also argues that a properly designed PIM would be (1) tied to a policy goal, (2) clearly defined, (3) quantifiable using reasonably available data, (4) sufficiently objective and free from external influences, (5) easily interpreted, and (6) easily verifiable (CLF Reply Brief at 5). CLF asserts that although the Company meets some of the aforementioned objectives, the proposed EV PIMs are not free from external influences (CLF Reply Brief at 5). CLF maintains that, as designed, the EV Adoption PIM does not accurately measure the Company's success in implementing the Phase II EV Program (CLF Brief at 28). Alternatively, CLF argues that a more viable EV PIM would be on usage of EV charging stations (CLF Brief at 28).

Lastly, CLF argues that the EVSE Cost Containment PIM does not include any financial downside for the Company, which fails to meet the goal of symmetry in PIM design (CLF Brief at 28). CLF argues that symmetry is needed if such a PIM can be considered for approval (CLF Brief at 28-29).

f. DOER

DOER supports incentivizing the Company to reduce peak demand on its distribution system, but recommends modifications to the Peak Reduction PIM to avoid duplicative policies (DOER Brief at 28). DOER argues that the Company has provided no basis for the Department to deviate from the precedent that the appropriateness of incentives is significantly influenced by the fact that the incentive is proposed in lieu of the return on capital investment that could cost the ratepayers more than the incentive (DOER Brief at 29, citing Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 17-13, at 46 (2018)). Specifically, DOER asserts that the Company recovers volt/var optimization costs, including return of and on capital costs plus operating expenses, through its grid modernization factor and, therefore, the Department should not include volt/var optimization in the Company's PIM (DOER Brief at 30; DOER Reply Brief at 5). DOER suggests that in any areas where National Grid already is receiving a return on capital investments, the Department should direct the Company to submit a compliance filing recalculating its proposed PIM to exclude those measures from its peak demand MW target and reduce the proposed incentives accordingly (DOER Brief at 30).

DOER supports the Company's earning a PIM on the peak demand reduction achieved by third-party solar-plus-storage projects, as it will incent the Company to interconnect these projects onto its system, thereby providing peak reduction benefits to customers (DOER Brief at 31). Nonetheless, DOER argues that the Company should not receive incentives though its proposed Peak Reduction PIM for projects funded from capital on which the Company already earns a rate of return, particularly if such capital approval is based on the premise of the Company's operating such resources in a manner that reduces peak demand (DOER Brief at 31).

Additionally, within the Peak Reduction PIM, DOER suggests that the Department require the Company to provide additional reporting on peak reductions achieved during the winter, in addition to the summer peak periods, and on the Company's consideration of non-wires alternative in distribution system planning (DOER Brief at 28; DOER Reply Brief at 8-9). Specifically, DOER recommends that the Department direct the Company to track and report on the top three peak winter days and the associated two highest hours per day-event in both the Company's annual reliability report and annual PBR filing (DOER Brief at 32-33; DOER Reply Brief at 8). DOER recommends that the Department require this reporting because substantial portions of the annual reliability report are confidential and redacted and PIMs and metric performance need to be made public to inform stakeholders on the Company's performance under the PBR (DOER Brief at 33). DOER further recommends the Department direct the Company to update its 2011 non-wires alternative guidelines to determine that the Company is considering non-wires alternatives investments in its capital planning (DOER Brief at 34; DOER Reply Brief at 9). DOER recommends that the Company include the following non-wires alternative information on a project-by-project basis in its annual reliability report: rationale; cost savings; and capacity deferred (DOER Brief at 34).

DOER recommends that the Department approve the EVSE Cost Containment PIM but reject the EV Adoption PIM (DOER Brief at 25). With regard to the EVSE Cost Containment PIM, DOER argues that the Department set a precedent in D.P.U. 17-13 encouraging design of future performance incentives aimed at cost containment of capitalized and non-capitalized costs (DOER Brief at 26). Therefore, DOER recommends that the Department approve the EVSE Cost Containment PIM subject to the Department's finding any needed adjustments due to reduced funding ordered in other program areas (DOER Brief at 26).

DOER argues that the Department should reject the Company's EV Adoption PIM because it is based on outcomes outside of the Company's control and that other factors affect the decision to purchase an EV (e.g., EV prices, federal and state incentives) (DOER Brief at 26-28). Specifically, DOER asserts that the EV Adoption PIM is (1) subject to miscalculation, (2) not narrowly targeted, (3) does not minimize inconsistencies between the plan and its overall goal, (4) is not based on Company behavior, and (5) does not meet the Department's standard of review for performance incentives (DOER Brief at 27). DOER further argues that the Company based its EV adoption on U.S. Energy Information Administration projections for EV sales, but National Grid did not perform any analysis comparing those projections to historical EV sales in the Company's service territory (DOER Brief at 27). DOER also emphasized that the Company's activities in charging infrastructure may indirectly impact EV sales, but that National Grid has failed to demonstrate how its EV infrastructure deployment activities correlate to increased EV adoption (DOER Reply Brief at 10).

With regards to the customer experience scorecard metric, DOER recommends that the Department direct the Company to report in its annual PBR Plan filing the following additional metrics: (1) the number of complete interconnection applications that result in signed interconnection service agreements; (2) the number of interconnection applications that proceed to a transmission study and the number of interconnection requests that proceed under Section I.3.9 of ISO-NE's Transmission, Markets, and Services Tariff (Review of Market Participant's Proposed Plans); (3) interconnection study timelines for all projects; and (4) for each interconnected project, the estimated cost of upgrades identified in the interconnection study and the actual cost of upgrades charged by the Company (DOER Brief at 37-38). DOER claims that the reporting of these metrics will allow DER customers, the Department, the Company, and other interested stakeholders to measure the relative accuracy of interconnection cost estimates (DOER Brief at 38).

DOER asserts that, to effectively measure the Company's performance, the Company should begin reporting data, as part of the customer experience scorecard metric, related to highly disruptive events that are currently excluded from the Company's existing reliability reporting requirements to inform an industry effort to develop resilience-related metrics (DOER Brief at 39). DOER states that the Company's proposed reporting metrics do not include a metric to allow the Department and stakeholders to monitor the Company's progress related to distribution system resilience during the PBR term (DOER Brief at 39). DOER states that reporting reliability performance for informational purposes related to highly disruptive events would not impact penalties associated with service quality reporting on reliability (DOER Brief at 41). Therefore, DOER suggests that the Department direct the Company to submit these reports with highly disruptive event information included so that they are accessible to the Department, DOER, and stakeholders for review and to assess the Company's performance on resilience (DOER Brief at 41).

In addition, DOER recommends that the Department establish a timeline for development of Company-specific measures to assess progress in planning for and maintaining resiliency, including, but not limited to, infrastructure investment planning and programs designed to improve system resiliency and system hardening (DOER Brief at 42). Furthermore, DOER recommends a time period of October 2019 through March 2020 to develop industry-wide resilience, or an alternate timeline as determined by the Department (DOER Brief at 42).

g. FSCS Coalition

The FSCS Coalition recommends that the Department reject the EV PIMs (FSCS Coalition Brief at 49). The FSCS Coalition argues that the proposed EV PIMs are not narrowly targeted or consistent with the standards of objectivity in other PBR mechanism proceedings (FSCS Coalition Brief at 49). Moreover, the FSCS Coalition contends that the EV PIMs' benchmarks and reward levels depend on subjective inputs that change from year to year, such as the U.S. Energy Information Administration EV sales forecast (FSCS Coalition Brief at 50). In addition, the FSCS Coalition argues that the EV Adoption PIM rewards National Grid for outcomes outside of the Company's control (e.g., EV prices) (FSCS Coalition Brief at 50).

h. MEDA

MEDA argues that the proposed PIMs do not incent the Company to ensure that transportation electrification benefits are spread equitably to low-income and disadvantaged customers and communities (MEDA Brief at 23). Therefore, MEDA recommends that the Department include an additional measure within one of the EV PIMs that measures transportation electrification services provided to low-income and disadvantaged communities (e.g., number of EVSE subsidies and installations annually for R-2 customers, stakeholder engagement, implementation of stakeholder process recommendations) (MEDA Brief at 23-24). MEDA contends that including this measurement does not increase the amount of that incentive the Company receives through the EV PIMs (MEDA Brief at 23).

MEDA states that it does not encourage the adoption of the PBR Plan and PIMs, but, should the Department approve all or part of the PBR Plan, MEDA recommends the addition of a metric that would elevate the needs of the Company's low-income customers (MEDA Brief at 20). Additionally, MEDA requests that the Department direct the Company to create a metric to track the rate of involuntary disconnections of low-income customers (MEDA Brief at 21). Specifically, MEDA suggests that the Company identify its current level of disconnections for non-payment and track improvement along this measure (MEDA Brief at 21). MEDA recommends that this metric for rate of involuntary disconnections be included within the Customer Ease PIM so that the Company's incentive under that PIM would be contingent on both the customer ease score and demonstration that involuntary disconnections for non-payment were reduced or were held below a level to be established by the Department (MEDA Brief at 21-22). Alternatively, MEDA states that, if the Department chooses not to create a disconnection metric within an existing PIM, then the Department should establish a scorecard metric to measure involuntary disconnections (MEDA Brief at 22). MEDA acknowledges that the Company has made clear that it is willing to work with MEDA to develop a scorecard metric to assess the rate of involuntary disconnections as a measure of energy affordability (MEDA Reply Brief at 11, citing Company Brief at 148).

In addition, MEDA states that the Company raised the possibility of tracking the amounts of arrearages carried by low-income customers, rather than disconnections (MEDA Reply Brief at 11, citing Company Brief at 148). MEDA argues that any metric that tracks arrearages must also be paired with a measure of disconnections, as they both stem from the same underlying causes, i.e., insufficiency of household income to pay for basic necessities, and affordability challenges when paying for electric utility service (MEDA Reply Brief at 11-12). Therefore, MEDA asserts that tracking rates of involuntary disconnection of service is a more appropriate and meaningful scorecard metric than measuring rates and levels of customer arrearages (MEDA Reply Brief at 12). Additionally, if arrearages were to be tracked, that measure should be used only as a scorecard metric if paired with data that tracks involuntary disconnections (MEDA Reply Brief at 12).

i. NECEC

NECEC argues that the Company's proposed scorecard metrics should be modified to track actual performance and not commitments (NECEC Brief at 10). NECEC argues that three of the Company's proposed five actions to achieve the reductions with its transportation fleet under the proposed GHG emissions reduction scorecard metric are not appropriate (NECEC Brief at 10). NECEC states that the Company should remove the following actions: (1) Edison Electric Institute five-percent commitment to procuring EVs; (2) continuing to meet or exceed the requirements of the Energy Policy Act of 2005, Pub. L. 109-58; and (3) National Grid USA President, Dean Seavers, serving as co-chair of the Alliance to Save Energy Commission (NECEC Brief at 10). NECEC claims that the reductions associated with meeting the Federal Energy Policy Act will be met regardless of whether the scorecard metric is approved and will not result in any additional GHG reductions (NECEC Brief at 10-11). Similarly, the Company already has pledged to spend five percent of its annual procurement budget on plug-in EVs and technologies (NECEC Brief at 11). Lastly, NECEC states that, although Mr. Seavers efforts as co-chair may lead to incremental GHG reductions by other parties, the Company should not be able to claim emissions by other parties in the Company's scorecard metrics (NECEC Brief at 11).

NECEC argues that the metrics proposed within the Company's DER customer experience scorecard do not provide the information necessary to proactively identify problems or costs associated with interconnecting DER customers to the Company's distribution system (NECEC Brief at 11). NECEC recommends that the Company's proposed DER customer experience scorecard be expanded to include the following: (1) a survey of interconnecting customers; (2) a review of group studies; and (3) tracking of interconnection contributions in aid of construction ("CIAC") (NECEC Brief at 12). NECEC suggests that the survey should be similar to the survey that the Company detailed in its proposed Customer Ease PIM (NECEC Brief at 12). For a review of group studies, NECEC suggests that the Company track the following for each group study: (1) number of group members; (2) number of affected system operators; (3) nameplate capacity of each group member's interconnected facility; (4) aggregate capacity of group members' interconnected facilities; (5) timeline for review; (6) total interconnection costs, inclusive of costs of studies and system modifications; (7) study and system modification costs allocated to each group member; and (8) whether each project was ultimately interconnected (NECEC Brief at 14). NECEC states that tracking group studies will provide the information necessary to proactively identify problems or costs associated with interconnecting DER customers to the Company's distribution system to ensure minimal obstacles to continued DER interconnections (NECEC Reply Brief at 11). NECEC recommends that the Company track CIAC so that the Department and stakeholders have an accurate understanding of and transparency into CIAC for the interconnection of distributed generation (NECEC Brief at 15). Specifically, for all interconnections of distributed generation, NECEC proposes that the Company track: (1) individual CIAC; (2) aggregate CIAC; (3) individual CIAC carrying charges; (4) aggregate CIAC carrying charges; and (5) of the aggregated CIAC collected, the amount paid in taxes compared to the amount kept by National Grid (NECEC Brief at 15). NECEC states that tracking CIAC costs in a transparent manner, and with precise understanding of terminology, will be vital to understanding where those funds are found in the Company's accounting systems and whether and how they are being reconciled and repaid to customers based on actual incurred costs and liabilities (NECEC Reply Brief at 12).

NECEC suggests a scorecard metric to track the allocation of net metering credits and alternative on-bill credits so that the Department and stakeholders have a better understanding of these items (NECEC Brief at 16). NECEC states that the performance tracking would include the following: (1) the time to accrue net metering credits or alternative on-bill credit on the community solar provider's account; (2) the time to allocate the net metering credits or alternative on-bill credit from the community solar provider's account to recipient customers (3) any errors in the allocation process; (4) the time to provide reports to community solar providers on banked and allocated net metering credits and alternative on-bill credit; (5) the time to notify community solar providers of closed recipient customer accounts; and (6) the frequency with which community solar providers are allowed to update their allocation forms (NECEC Brief at 16-17). Accordingly, NECEC recommends that the Department require the Company to add this scorecard metric (NECEC Brief at 18).

Turning to the Company's proposed PIMs, NECEC supports the Peak Reduction PIM with the exclusion of (1) distribution system equipment and (2) Company actions associated with energy efficiency (NECEC Brief at 20). Further, NECEC recommends that the Department consider potential reward and penalty levels that are considerably higher and more meaningful than the magnitude of the current reward and current penalty under the timeline enforcement mechanism (NECEC Brief at 24-25).

NECEC further recommends that the Department find in this proceeding that the adoption of a full interconnection PIM within the Company's PBR Plan is reasonable and beneficial because it recognizes the following two factors that will be critical to improving the state of interconnection in National Grid's territory: (1) updating the rules governing the Company's processing and execution of distributed generation interconnection applications and (2) updating the financial incentives driving the Company's decision-making surrounding allocation of resources and overall distribution system planning (NECEC Brief at 22, 28). NECEC argues that the failure to acknowledge a growing distribution system interconnection problem by the entity that is the distribution system's manager highlights why it is imperative for the Department to require the Company to implement NECEC's interconnection PIM recommendations (NECEC Reply Brief at 6-7). NECEC states that such a finding will signal the need for immediate improvements to the Company's distributed generation interconnection process and lay the groundwork for the future implementation of a full, financially consequential interconnection PIM reflecting the most up-to-date policy and standards for interconnection (NECEC Brief at 23).

NECEC recommends that, until the adoption of an interconnection PIM, the Department should require the Company to immediately begin collecting, tracking, and reporting the following information that is currently not captured in the TEM: (1) actual calendar days and business days to count the duration between different interconnection milestones; (2) the number of days that an interconnection application is on hold; (3) the number of business days from submittal of interconnection application to commencement of an interconnection study; (4) the number of business days from commencement of an interconnection study to the issuance of an interconnect services agreement; (5) design and construction timelines of distribution-system modifications; (6) construction costs of distribution-system modifications; and (7) the number of business days from a customer's execution of an interconnection service agreement to the Company's issuance of an authorization to interconnect (NECEC Brief at 23-24).

NECEC proposes that the Department require the Company to (a) solicit non-wires alternative proposals when the "wires" solution is $500,000 or more and non-wires alternatives could meet one of the criteria identified in G.L. c. 164, § 146(b), and (b) screen projects for potential non-wires alternatives annually when it files its resiliency reports with the Department, and (c) solicit non-wires alternatives for the projects that meet the screening criteria (NECEC Reply Brief at 13). Furthermore, NECEC states that the Company should include in its resiliency reports a list of projects that did and did not meet the screening criteria, as well as a summary of the results of its non-wires alternatives (NECEC Reply Brief at 13). NECEC concludes that the Department should (1) make a finding that the adoption of an interconnection PIM under the Company's PBR Plan is reasonable and beneficial, (2) establish procedural steps to incorporate any relevant outcomes of Inquiry into Distributed Generation Interconnection, D.P.U. 19-55 (May 22, 2019) into an interconnection PIM before the end of the Company's five-year PBR Plan, and (3) require the Company to immediately begin tracking and reporting interconnection metrics (NECEC Brief at 29; NECEC Reply Brief at 7).

j. Tesla

Tesla proposes that the Department approve, with modifications, the proposed PIM that involves crediting the Company for an increase in the number of EVs in the

Commonwealth (Tesla Brief at 1). Tesla adopts the position it espoused in testimony that the PIM for EV adoption should reward improvements that are within the Company's control (Tesla Brief at 18).

k. Company

With regard to its proposed Customer Ease PIM, since the initial filing, the Company planned some additional projects to improve customer ease, including additional digital enhancements, interactive voice response, and customer touch point enhancements (Company Brief at 71). The Company argues that, although the benefits to customers of increased customer ease are not easy to quantify or monetize, the size of the proposed incentive is reasonable in providing a meaningful incentive that will drive management attention and Company performance, while ensuring that customers retain the majority of value created by customer ease actions (Company Brief at 72).

The Company disagrees with intervenors' assertions regarding the EV Adoption PIM (Company Brief at 130). The Company acknowledges that there are some factors outside of its control that influence a customer's decision to purchase an EV (Company Brief at 130). The Company states, however, that most of the intervenors assume these factors will all positively influence a customer's decisions to buy an EV and that the Company will be the passive beneficiary of those exogenous factors (Company Brief at 130). The Company argues that most intervenors ignore the many negative factors that cut against a customer's decision to purchase an EV, such as lower gasoline costs, a downturn in the economy, sunsetting of federal and state EV incentives and rebate programs (Company Brief at 130).

The Company states that it designed the EV Adoption PIM such that exogenous factors will not diminish the need for the Company to perform activities within its control to achieve the specified targets (Company Brief at 131). The Company concludes that one of the most important factors influencing a customer's decision in whether to buy an EV is the availability and convenience of charging infrastructure (Company Brief at 130; Company Reply Brief at 61).

The Company disagrees with the Attorney General's assertion that the EV Adoption PIM should be rejected because the incentive is not scaled to match the Company's actual activity within the broader EV market (Company Brief at 132-133). The Company argues that the Attorney General disregards both the scale of the proposed incentive and the role of the Company in the Phase II EV Program to provide a highly visible boost to the availability of EV charging, which should spur EV adoption (Company Brief at 133).

The Company also disagrees with the FSCS Coalition that the EV Adoption PIM should be rejected because it is extraordinarily sensitive to subjective changes in inputs (Company Brief at 133). The Company states that it developed the EV Adoption PIM based on a reasonable set of assumptions at the time of filing, primarily based on the 2018 U.S. Energy Information Administration Annual Energy Outlook (Company Brief at 133).

The Company disagrees with CLF's assertion that including usage of EV charging stations would be a superior metric to the EV Adoption PIM (Company Reply Brief at 63). The Company argues that CLF provides no detail or analysis in support of this proposal and that, at this time, current metering and data collection limitations make it impractical to pursue the "usage" metric contemplated by CLF (Company Reply Brief at 63). The Company asserts that because it does not currently have an off-peak charging rate or program, there is no way for the Company to influence customer utilization numbers (Company Reply Brief at 63). Further, the Company concludes that a metric based on EV charging usage is not suitable because it is not closely tied to the underlying policy goal of driving increased EV adoption in the Commonwealth and, therefore, it should be disregarded by the Department (Company Reply Brief at 63).

The Company states that the Clean Energy Parties' assertion that the EV Adoption PIM should be modified to focus on the realization of fuel cost savings from the use of electricity as a transportation fuel at both home charging units and the public charging stations supported by the Phase II EV Program is impractical because it does not account for the fact that gasoline prices fluctuate every day and vary from town-to-town, neighborhood-to-neighborhood, and station-to-station (Company Reply Brief at 63). The Company disagrees with the Clean Energy Parties' response that the Company could use U.S. Energy Information Administration projected gasoline and diesel prices to establish a baseline for measurement (Company Reply Brief at 63). The Company maintains that this response does not address the Company's argument that fuel costs cannot be measured in a practical manner that would yield meaningful data on fuel savings (Company Reply Brief at 63). The Company expects that while customers will use the charging stations deployed by the Company in its service territory, customers may also use charging stations already deployed in the Company's service territory and charging stations outside of the Company's service territory (Company Reply Brief at 64). In conclusion, the Company states that the Clean Energy Parties' proposal would not provide a complete picture of customer charging patterns for the purpose of accurately calculating total fuel savings and the proposal should be rejected because it does not present a more favorable alternative to the Company's proposal (Company Reply Brief at 64).

The Company disagrees with CLF and the Clean Energy Parties that the proposed EV Adoption PIM is not sufficiently ambitious (Company Reply Brief at 64). The Company states that CLF and the Clean Energy Parties fail to recognize the gulf that exists between current EV adoption levels and the Commonwealth's ZEV goals, as well as the relationship between the EV Adoption PIM and the size of the Phase I and Phase II EV Programs (Company Reply Brief at 64-65). The Company reasserts that it developed its EV Adoption PIM baseline starting with the actual EV vehicles in operation in its territory and forecasting expected baseline growth using the U.S. Energy Information Agency's forecast of EV adoption (Company Reply Brief at 65).

The Company disagrees with the Attorney General, Acadia Center, and CLF that the Department should either reject or modify the PIMs because they do not have a symmetrical penalty as part of their design (Company Brief at 116). The Company argues that in the context of energy efficiency programs, experience has shown that penalties create an adversarial environment, shift the focus from achieving goals, and affect implementation in counterproductive ways (Company Brief at 116). Additionally, the Company argues that, while developing the PIMs, the Company determined that incentives are structured to create customer value beyond threshold levels, but that, because areas of measurement and levels of influence that the Company may achieve are new, penalties would be inappropriate at this time (Company Brief at 117). Further, the Company argues that the introduction of penalties could have unintended consequences that would detract from the pursuit of regulatory and policy goals (Company Brief at 119). Lastly, the Company contends that investors and lenders could view a penalty as an increase in risk that could potentially result in a higher cost of capital for the Company, and ultimately for customers (Company Brief at 119).

The Company further argues that the delivery of the Phase II EV Program objectives will be subject to a prudence review by the Department and the Company is at risk of disallowance if costs are not prudently incurred, so there is no need to include a financial downside for under-delivery on the program objectives (Company Brief at 118). The Company also contends that, to the extent the Company spends funds outside of the Phase II EV Program budget to help meet the PIM goals, the Company would have a built-in downside risk of lower earnings if EV adoption did not meet or exceed the threshold level of the PIM (Company Brief at 118; Company Reply Brief at 57).

The Company disagrees with the Attorney General that the Company has inappropriately grafted an outdated 1995 Department precedent (i.e., D.P.U. 94-158) onto a vastly changed 2019 regulatory environment to support the approval of its PIMs (Company Brief at 119). The Company states that it has demonstrated that its PIMs comply with the broadly applicable principles articulated by the Department in D.P.U. 94-158, namely: (1) identifying the specific policy objective intended to be met by the targeted incentive;

(2) demonstrating why a broad-based proposal otherwise fails to meet these needs; and (3) showing that any inconsistency between the plan and its overall goals is minimized (Company Brief at 120, citing D.P.U. 94-158, at 62-63).

The Company disagrees with NECEC's proposed interconnection PIM and the associated metrics and claims they are not appropriate for several reasons (Company Brief at 139). The Company asserts that NECEC's proposal is inappropriately based on timelines that are largely out of the Company's control, such as interconnection process hold-ups due to customer or third-party delays and construction timelines, and are highly dependent on the complexity of the project, the completeness in the information submitted, and the amount of redesign and rework the customer undertakes to reduce system impact or to improve on preliminary designs (Company Brief at 139). The Company maintains that it already is subject to the timeline enforcement mechanism (Company Brief at 139). In addition, National Grid asserts that some aspects of the proposed interconnection PIM are largely redundant to the Company's proposed Peak Reduction PIM (Company Brief at 140). The Company argues that, if the interconnection PIM were adopted and it included penalties, the Company would shift focus from meeting or exceeding goals to ensuring that penalties are not incurred reducing the Company's appetite for innovation and change related to the interconnection process (Company Brief at 140). The Company asserts that the D.P.U. 19-55 proceeding is a more appropriate forum for resolution of timeline enforcement mechanism issues because it provides opportunity for key stakeholders that have not intervened in this proceeding to provide valuable input (Company Reply Brief at 69). The

Company contends that there is no basis for imposing an additional set of reporting requirements without additional stakeholder and other utility input (Company Brief at 141). Accordingly, the Company argues that the Department should not adopt NECEC's proposed additional reporting metrics (Company Brief at 141).

National Grid agrees with DOER, as discussed at the evidentiary hearing and in the Company's rebuttal testimony, that it can update its non-wires alternative screening criteria to be consistent with the New York guideline applicable to its affiliate Niagara Mohawk Corporation (Company Brief at 128, citing Exh. NG-PBRP-Rebuttal-1, at 9-10, 45-46; Tr. 8, at 1078-1079). The Company recommends that this reporting be included in its annual reliability report filed with the Department or in its annual electric distribution resiliency report required by recent Massachusetts energy legislation, An Act to Advance Clean Energy, Chapter 227 of the Acts of 2018 (Company Brief at 128).

The Company proposes a peak demand reduction PIM geared toward increasing the Company's focus and efforts on peak demand management and driving expanded or innovative Company efforts to provide these benefits to customers (Company Brief at 60). The Company agrees that reductions in peak demand can provide benefits to all customers largely through avoided capacity market and energy costs (Company Brief at 60, citing State of Charge: Massachusetts Energy Storage Initiative Study, published July 2016, Department of Energy Resources and Massachusetts Clean Energy Center). Over the course of the proceeding, the Company revised its base interconnection volume forecast to obtain a new minimum threshold, target, and maximum levels (Company Brief at 61, citing Tr. 8, at 1187-1188; RR-DPU-24). Also, the Company removed standard technology upgrades as part of the Peak Reduction PIM (Company Brief at 61, n 8, citing Exh. NG-PBRP-Rebuttal-1, at 5-6).

The Company is amenable to including some form of winter peak reporting as part of its annual reliability reports and in the annual PBR report as requested by DOER, but the Company does not agree with DOER that winter peak demand should be part of the Peak Reduction PIM (Company Brief at 127). The Company states that it considered including winter peak demand reduction in the Peak Reduction PIM but left it out because capacity expansion is driven by the system peaks and equipment capability limitations experienced during summer peak load periods (Company Brief at 127). The Company also argues that it would not be appropriate to include winter peak reduction in the Peak Reduction PIM because the Company is working with energy efficiency program administrators to develop demand response programs to address winter peak issues (Company Brief at 128).

The Company states that because intervenors did not oppose the Company's proposed customer engagement scorecard metrics, it should be approved by the Department (Company Brief at 143). The Company argues that the Department should not adopt NECEC's proposed modifications to the DER customer experience scorecard metric because the information for a survey of interconnecting customers, a review of group studies, or tracking of CIAC is either currently available or inappropriate due to the structure and subjectivity of the information requested (Company Brief at 144-145). The Company disagrees that it should include a customer survey as part of the DER customer experience scorecard metric because the Company regularly holds distributed generation seminars to explain the interconnection process and to take installer questions and comments (Company Brief 144). The Company also argues that such a survey would not result in the most useful or accurate feedback on the most important issues to distributed generation customers and, therefore, should not be adopted by the Department (Company Brief at 145).

The Company agrees with three of the five metrics proposed by DOER for the DER customer experience scorecard metric (Company Brief at 146). The Company agrees that it is reasonable and is willing to report the following: (1) the number of interconnection applications and the number of interconnection applications that result in signed interconnection service agreements; (2) the number of interconnection applications that go to transmission study and how many go to the Section I.3.9 process with ISO-NE; and (3) interconnection study timelines for all projects (Company Brief at 145-146). The Company disagrees with the fourth proposed reporting metric for cost of studies and the cost of upgrades identified in the study and the actual cost of upgrades required for interconnections. The Company states that, although the cost of upgrades as estimated and charged to distributed generation customer is available, the Company is not required to, and currently does not reconcile all project cost estimates with actual amounts after the completion of a project, and, therefore, the Company objects to any metrics that are based on actual amounts (Company Brief at 146). The Company also disagrees with DOER's fifth proposed metric, cost containment of interconnection requests (Company Brief at 146). The

Company maintains that this metric is inappropriate and would be highly problematic to construct and implement (Company Brief at 146).

The Company also asserts that the Department should reject NECEC's proposed modifications to the GHG emission reduction metric because it would result in an incomplete picture of the Company's GHG emissions reduction activities (Company Brief at 142). The Company states that it included the Edison Electric Institute commitment, Energy Policy Act of 2005 compliance, and Mr. Seavers' activities to provide a complete picture of the activities undertaken by the Company to achieve the corporate-wide emissions reduction of 80 percent reductions by 2050 (Company Brief at 142). Furthermore, the Company argues that the Edison Electric Institute pledge is appropriate because it is directly related to the Company's efforts to reduce transportation fleet emissions (Company Brief at 142-143).

The Company agrees with MEDA's recommendation and agrees that it would be informative and beneficial to track the rate of involuntary disconnections of residential customers as a scorecard metric (Company Brief at 147). The Company has some reservations about whether tracking the number of involuntary customer disconnections is the correct measurement to address MEDA's underlying intention, which the Company believes is to reduce the number of residential customers who are struggling to pay their bills (Company Reply Brief at 75). The Company also states that the development of this metric takes time and, as such, proposes to develop this metric in consultation with MEDA and the National Consumer Law Center as part of a compliance filing to be made after the conclusion of this proceeding (Company Brief at 148). Alternatively, the Company proposes that this metric be developed at the time of the Company's PBR Plan annual filing with the Department in 2020 (Company Brief at 148).

The Company agrees with DOER's recommendation to begin reporting data related to highly disruptive events that are currently excluded from the Company's existing reliability reporting requirements (Company Brief at 153). The Company is willing to report on highly disruptive events as a scorecard metric at the direction of the Department but notes that some information already is reported to the Department in the annual service quality report (Company Brief at 153). The Company further agrees with DOER that industry-wide resiliency metrics should be developed collaboratively, outside of the instant proceeding, with other Massachusetts utilities, DOER, and other interested stakeholders (Company Brief at 153).

The Company is willing to accept the recommendations of DOER to add the following additional scorecard metrics: (1) the number of interconnection applications and the number of interconnection applications that result in signed interconnection service agreements; (2) the number of interconnection requests that go to transmission study and how many go to the section I.3.9 process with ISO-NE; and (3) interconnection study timelines for all projects (Company Brief at 79, citing Exh. NG-PBRP-Rebuttal-1, at 33).

In response to NECEC's proposal to track the allocation of net metering credits and alternative on-bill credit, the Company contends that it is not appropriate in this instant proceeding to create a new scorecard metric tracking all of NECEC's proposed measures because it would be applicable only to the Company, and some of this information already is tracked elsewhere (Company Brief at 151). The Company states that in D.P.U. 17-140, the Department required the tracking of several net metering credit and alternative on-bill credit measures including (a) the time for bill credits to appear on a recipient customer bills, with a requirement of three billing cycles and (b) incentive and credit allocation errors and delays (Company Brief at 151).

The Company acknowledges DOER's recommendation for the Company and other electric distribution companies to take strategic electrification into account in system planning, in general, and resiliency planning in particular (Company Brief at 152). The Company states that DOER's recommendation should be explored further, but it is not well-developed enough at this stage to form the basis of a specific new scorecard metric in this proceeding (Company Brief at 153). Further, the Company states that the development of such a metric would be best explored outside the scope of this proceeding, with participation from other electric distribution companies and stakeholders (Company Brief at 153).

The Company contends that it is in the public interest for PIMs and scorecard metrics to be linked to policy objectives with high perceived customer value (Company Brief at 80). The Company concludes that both customers and the Commonwealth as a whole will benefit from more active and engaged utility efforts to achieve the policy objectives underlying the PIMs and scorecard metrics proposed by the Company (Company Brief at 80).

4. Analysis and Finding

a. Review Criteria

The Department has reviewed the application of incentive mechanisms in specific contexts.[44] Nonetheless, the Company's request to receive performance incentives within the context of a PBR proposal is an issue of first impression. In making its determination of whether a PIM is appropriate, the Department relies on a two-prong test: (1) whether the PIM satisfies certain threshold principles; and (2) whether the PIM meets the design guidelines.

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. 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. Conversely,

---

44 For example, the Department has adopted incentive mechanisms applicable to energy efficiency programs and gas supply planning actions. 2010 – 2012 Three-Year Energy Efficiency Plans, D.P.U. 09-116 through D.P.U. 09-120, at 124 (2010) (Department accepts electric Program Administrators' performance incentive mechanism structure and statewide incentive pool); Ratemaking Treatment of Margins Generated From Interruptible Transportation, Capacity Release, Off-System Sales, Interruptible Sales, Portfolio Management and Optimization Agreements, and Related Transactions, D.P.U. 10-62-A (2013) (Department allows sharing of margins between local gas distributions companies and ratepayers).

performance incentives are generally not appropriate where the affected activity is within the distribution company's public service obligations. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company, D.T.E./D.P.U. 06-107-B at 55-60 (2009); 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). Thus, the Department finds that in order to be considered on its design merits, a PIM must first 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.

Second, upon determining that a PIM meets these threshold principles, the Department must determine that the proposed incentive mechanism meets appropriate design guidelines. Here again the Department looks to past practice. 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 electric and gas distribution companies, 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. 17-13, at 42-43, 46; 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. The Department finds that it is appropriate to adopt these design guidelines to evaluate proposed PIMs.

b. Customer Ease

The Company's Customer Ease PIM is designed to award an incentive if the Company's Customer Ease score reaches certain thresholds in each year of the PBR term (Exh. NG-PBRP-1, at 54-55). The Company maintains that increasing customer satisfaction is important and aligns with customer interests (Exh. NG-PBRP-1, at 84-85).

As part of their public service obligation, distribution companies are responsible for providing low-cost and reliable service to customers. Massachusetts-American Water Company, D.P.U. 95-118, at 47 (1996); 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 service quality expectations in the course of their day-to-day business operations. Revised Service Quality Guidelines, D.P.U. 12-120-D (2015). The Department finds that the customer interactive elements of the Customer Ease 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 its customer ease score and rejects the Company's proposed Customer Ease PIM. Further, the Department finds that the customer engagement scorecard metric will provide appropriately sufficient information to accomplish the objective of the proposed Customer Ease PIM without imposing an additional reporting burden on the Company (Exh. NG-PBRP-1, at 85, 101). The Department addresses the adoption of this scorecard metric below.

c. Peak Reduction

The Company proposes a Peak Reduction PIM that tracks the average peak reduction from Company-influenced or Company–owned measures during the five top peak events in a given year (Exh. NG-PBRP-1, at 62-63). Approximately 94 percent of the estimated peak reduction from these measures stems from Company interconnection to its distribution system of solar and energy storage assets (RR-DPU-24, Att.). The remaining six percent of estimated peak reduction from these measures stems from the Company's implementation of volt/var optimization on its distribution system (RR-DPU-24, Att.). The Company would receive a performance incentive based on the amount of measured and estimated peak reduction achieved by interconnected assets and volt/var optimization performance (Exh. NG-PBRP-2 (Rev. 2); RR-DPU-24, Att.).

The Department recognizes that, in general, company-led system peak reduction actions can advance public policy goals of the Commonwealth, including reducing GHG emissions, and company actions taken specifically to reduce system peak demand are outside a distribution company's public service obligation (Exh. NG-PBRP-1, at 52-53, 63). Therefore, an incentive mechanism designed to drive Company actions that directly and measurably reduce system peak demand can satisfy the threshold principles.

Nonetheless, upon examination of its underlying design, the Department finds that the proposed Peak Reduction PIM is deficient in meeting the design guidelines. First, almost all of the Company's proposed peak reduction would originate from an increase in the rate of the Company's interconnection activities, but, by interconnection alone, the Company does not have a distinct and clear role in bringing about peak reduction because it does not have control over the customers' interconnected assets (Exh. NG-PBRP-1, at 65-66). Rather, it is up to the interconnected customers to take action in reducing peak and the Company's action of interconnecting itself does not directly lead to peak reduction. Second, the Company already would be rewarded with forward capacity market net revenue sharing on customer-owned assets under certain circumstances. D.P.U. 17-146-B at 56-59.[45] Third, the proposed Peak Reduction PIM provides a perverse incentive to the Company, because if National Grid earns the performance incentive on an energy efficiency customer's asset, that customer is restricted from participating in the active demand response program under the approved energy efficiency plan (Exh. NG-PBRP-1, at 68; Tr. 8, at 1172-1175). Lastly, the activities in the proposed Peak Reduction PIM are not activities that can be sufficiently monitored, quantified, and verified, because approximately 30 percent of the asset output would be estimated, not measured or verified (Exhs. NG-PBRP-1, at 75; DPU-NG 26-4; Tr. 8, at 1176-1179). In conclusion, the Company's proposed Peak Reduction PIM fails to meet many of the design guidelines. Therefore, we reject the Company's proposed Peak Reduction PIM because it fails the design guidelines related to (a) distinct action by the Company, (b) action rewarded through another mechanism, and (c) insufficient monitoring.

45 Electric distribution companies are allowed a 20-percent net revenue share through participation with distributed generation facilities in the forward capacity market administered by ISO-NE. D.P.U. 17-146-B at 59.

d. Transportation Electrification

In Section XI.D., below, the Department disallows the majority of the proposed Phase II EV Program. Consequently, we decline to approve any PIMs related to the Phase II EV Program. Nonetheless, we find it appropriate to include our conclusions regarding the Company's design of the proposed EV PIMs to provide guidance for future EV PIM proposals.

In evaluating the proposed EV PIMs, the Department finds that a reasonably designed transportation electrification PIM would generally meet the threshold principles, because a transportation electrification program is meant to support the advancement of the Commonwealth's public policy goals (Exhs. NG-PBRP-1, at 76, 83; NG-RS-1, at 4, 5). In addition, a transportation electrification program is outside of the Company's public service obligations (Exh. AC-1-4; Tr. 8, at 1046, 1096). Therefore, the EV PIMs proposed by the Company would generally meet the threshold principles. Nonetheless, we find that the proposed EV PIMs are not adequately designed and are inconsistent with the Department's PIM design guidelines.

There are additional design deficiencies with each of the proposed EV PIMs, as discussed below. For the EV Adoption PIM, although the Company states that the proposed Phase II EV Program will result in a significant expansion of EV charging infrastructure in the Commonwealth, we are concerned with the Company's proposal to base the performance incentive on the incremental number of EVs adopted (Exh. NG-PBRP-1, at 77-80). We agree with the Company that, the Phase II EV Program may have some effect on incremental

EV adoption in its service territory (Exhs. DPU-NG 24-7; Network 2-7; FSCS 2-7). Nonetheless, we find that merely deploying EV charging infrastructure is not the only factor, or the main factor, to spur EV adoption (Exh. AG-EAB at 38-39). There are many factors outside the Company's control that may contribute to spurring EV adoption, for example, EV purchase prices, government incentives, and availability of EVs (Exh. AG-EAB at 4, 38-39). In conclusion, by building EV charging infrastructure alone, the Company does not play a distinct and clear role in increasing EV adoption.

Regarding the EVSE Cost Containment PIM, the Department appreciates the Company's attempt to mitigate both capitalized costs and expenses (Exh. NG-PBRP-1, at 83). Nonetheless, the Department is concerned that the proposed EVSE Cost Containment PIM cannot be sufficiently monitored, quantified, and verified (Exh. AG-EAB at 41). In D.P.U. 17-13, the Department authorized cost recovery for the Phase I EV Program, urged National Grid to consider performance incentive designs in order to contain costs, and stated that we would closely monitor the Company's spending practices through the annual cost recovery filings and the stakeholder process. D.P.U. 17-13, at 45. The Department aimed to address cost containment as it related to the actual costs of the program and not the estimated costs. Nevertheless, the Company has based the EVSE Cost Containment PIM on estimated rather than actual costs from the Phase I EV Program (Exhs. AG-EAB at 10; AG 18-14; DPU-NG 8-10; Tr. 1, at 27). The proposed EVSE Cost Containment PIM does not use actual costs and, therefore, the Departments finds that the proposed EVSE Cost Containment PIM would not be able to be sufficiently monitored, quantified, or verified.

In conclusion, we decline to approve the Company's proposed EV PIMs because of their significant connection to the Company's proposed Phase II EV Program, which the Department has substantially denied. Furthermore, we find several design issues that are inconsistent with the Department's PIM design guidelines, as we have outlined above.

e. Scorecard Metrics

In evaluating scorecard metrics, the Department needs to determine an appropriate suite of metrics to evaluate the ratepayer benefits created under the Company's PBR mechanism (Exh. NG-PBRP-1, at 15, 51-52). First, regarding the proposed customer engagement scorecard metric, the Department finds that this scorecard metric tracks the quality and convenience of customer interaction with appropriately developed baselines (Exh. NG-PBRP-1, at 100-101). This metric will measure the progress that the Company makes to improve customer engagement over the term of the PBR Plan, and we approve it. Therefore, the Department directs the Company to implement the customer engagement scorecard metric and to include the results in its annual PBR filing.

Second, regarding the proposed GHG emissions reduction scorecard metric, NECEC argues that three of the five proposed actions within the transportation fleet measure of this metric should be removed: (1) Edison Electric Institute five-percent commitment to procuring EVs; (2) continuing to meet/exceed the Energy Policy Act of 2005 requirements; and (3) National Grid USA President, Dean Seavers, serving as co-chair of the Alliance to Save Energy Commission (NECEC Brief at 10-11, citing Exh. NG-PBRP-1, at 98). Acadia Center supports NECEC's argument to remove those three actions (Acadia Center Brief at 13). The Company argues that the Department should reject NECEC's recommendation because removal of the three actions would result in an incomplete picture of the Company's GHG emissions reductions activities (Company Brief at 142, citing Exh. NG-PBRP-Rebuttal-1, at 28-29). The Department agrees with NECEC and Acadia Center that these three actions would be met absent the PBR Plan, and the purpose of the scorecard metric is not to show a complete picture of the Company's GHG reduction efforts. Rather the properly designed metric provides an effective means to evaluate the ratepayer benefits created under the Company's PBR mechanism. Therefore, the Department directs the Company to remove these three measures from its GHG emissions scorecard metric. We find that the remaining items in the GHG emissions scorecard metric are appropriately designed to monitor the Company's progress over the term of the PBR Plan and we approve them. Therefore, we direct the Company to implement GHG emissions reduction scorecard metric as modified and to report on the results in in its annual PBR filing.

Third, intervenors provided suggestions to expand the DER customer experience scorecard metric, but they did not recommend rejecting any of the measures proposed by the Company. NECEC suggests that the Department require the Company to expand this metric to include: (1) a survey of interconnecting customers; (2) a review of group studies; and (3) tracking of interconnection CIAC (NECEC Brief at 11-15). Acadia Center supports NECEC's proposed modifications (Acadia Center Brief at 13). The Company argues that the Department should not adopt NECEC's proposed modifications because the information is either currently available or inappropriate due to the structure and subjectivity of the information requested (Company Brief at 144-145).

The Department agrees that it is inappropriate to address the issue regarding group studies in this instant proceeding because D.P.U. 17-164 is dedicated to this issue, and that proceeding allows other stakeholders and other utilities the opportunity to provide valuable input at an industry-wide level. Therefore, the Department declines to adopt NECEC's proposed modifications to the DER customer experience scorecard metric.

DOER offered additional metrics to include within the DER customer experience scorecard metric pertaining to the Company's interconnection process performance (DOER Brief at 37-39).[46] Consistent with the decision above, the Department concludes that adopting interconnection performance metrics in this instant proceeding is inappropriate because D.P.U. 19-55 is dedicated to this issue and that proceeding allows other stakeholders and other utilities the opportunity to provide valuable input at an industry-wide level. Therefore, the Department declines to adopt DOER's proposed modifications to the DER customer experience scorecard metric. Accordingly, the Department approves the Company's DER customer experience scorecard metric and directs the Company to implement it and include the results in in its annual PBR filing.

NECEC recommends creating a scorecard metric composed of several net-metering and alternative on-bill credit criteria (NECEC Brief at 16-18; Exh. NECEC–NP-1, at 27-28). The Department agrees with NECEC that much of the information it proposes to be tracked

---

46 Acadia Center supports DOER's proposed modifications (Acadia Center Brief at 14).

is valuable (Exh. NECEC-NP-1, at 28). Nonetheless, the Department addressed many of the issues that NECEC has raised here in the SMART proceeding, which is a program approved across all the Commonwealth's electric distribution companies. D.P.U. 17-140-A at 38, 45. Therefore, the Department finds that the instant proceeding is not the appropriate venue to address these issues. The SMART Program is a statewide, Department-approved program that was uniformly developed for all the Commonwealth's electric distribution companies. D.P.U. 17-140-A at 1-2, 211. Further, the Department's historical treatment of the net metering program is to create a standardized process, where the policies and regulations for net metering are created uniformly across all the electric distribution companies. 220 CMR 18.00; Single Parcel and Subdivision Rules Net Metering Inquiry, D.P.U. 17-22 (2017); D.P.U. 17-140-A; D.P.U. 17-146-A; D.P.U. 17-146-B. The requirement for the Company to report the information recommended by NECEC and to create a scorecard metric for DER allocation and billing, without the input of the Commonwealth's other electric distribution companies and stakeholders, would be inconsistent with the Department's uniform implementation of net metering policies. Consequently, the Department declines to adopt NECEC's recommendations on DER allocation and billing.

Some intervenors propose new stand-alone scorecard metrics. MEDA suggests that the Company track the rate of involuntary disconnections of low-income customers (MEDA Brief at 21). Acadia Center supports this additional metric (Acadia Center Brief at 14). The Company agrees that it would be informative and beneficial to track the rate of involuntary disconnections (Company Brief at 147-148; Exh. NG-PBRP-Rebuttal-1, at 27; Tr. 8, at 1080-1081). Nonetheless, the Company acknowledges that the details of this metric would take time to develop and proposes to work with MEDA and the National Consumer Law Center to develop a new metric (Company Brief at 147; Exh. NG-PBRP-Rebuttal-1, at 27). Therefore, the Department encourages the Company to work with stakeholders and other utilities to further refine a metric that would track the involuntary disconnections of low-income customers.

DOER recommend that the Company adopt a scorecard metric on the impact of strategic electrification on the distribution system (DOER Brief at 5).[47] DOER also recommends that the Company begin reporting data related to highly disruptive events that are currently excluded from the Company's existing reliability report (DOER Brief at 39). The Company acknowledged that both of these metrics could be explored further (Company Brief at 152-153). The Department finds that both of these metrics would be beneficial at the statewide industry level but are not appropriate to address in the instant proceeding. Therefore, the Department encourages the Company to work with intervenors, stakeholders, and the other electric distribution companies in the potential development of a strategic electrification metric and a resiliency metric.

Several intervenors make recommendations with respect to the Company's consideration of and reporting on non-wires alternatives. Acadia Center and NECEC both recommend that the Company be required to establish procedures and protocols for issuing non-wires solicitations as a condition of the Department's approval of its PBRM (Acadia

---

[47] Acadia Center supports DOER's recommendation (Acadia Center Brief at 14).

Center Brief at 6, NECEC Reply Brief at 13). DOER recommends that the Department order the Company to update its 2011 non-wires alternatives guidelines (DOER Brief at 34). In response to the intervenors, the Company agreed to update its guidelines to be consistent with the New York guideline applicable to its affiliate Niagara Mohawk Corporation (Company Brief at 128, citing Exh. NG-PBRP-Rebuttal-1, at 9-10, 45-46; Tr. 8, at 1078-1079). The Company also agreed to report annually on its non-wires alternatives screening activity and recommended that such reporting be included in its annual reliability report filed with the Department, its annual electric distribution resiliency report required by recent energy legislation, An Act to Advance Clean Energy, Chapter 227 of the Acts of 2018, or its annual PBR filing (Company Brief at 128, Company Brief, Appendix A at 22-23). The Department agrees with intervenors that the consideration of non-wires alternatives is important as a means to improve reliability, resilience, and modernize the electric grid and directs the Company to update its non-wires alternatives guidelines as it has agreed to as well as report on its non-wires alternatives screening activity and competitive solicitations in both its annual electric distribution resiliency report and its annual PBR filing.

III. RATE BASE

A. Overview

The Company's test-year rate base was \$2,106,476,030, based on a total utility plant in service of \$4,646,054,511 (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 1).[48] To this amount,

---

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

the Company proposes a normalizing adjustment of $123,405,973 and a known and measurable deduction of $11,390,700 for a total proposed rate base of $2,218,491,303 (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 1). The Company's total proposed rate base consists of: $2,792,955,877 in net utility plant in service, $24,926,145 in materials and supplies, $2,088,555 in prepayments, and $70,006,225 in cash working capital; less, $393,573,111 in deferred income taxes, $245,368,659 in excess deferred income taxes,[49] $6,255,608 in CIAC, and $26,288,121 in customer deposits (see Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 1).

B. Plant Additions

1. Introduction

In D.P.U. 09-39, the Department approved the first iteration of the Company's current CIRM, which allows recovery of the revenue requirement associated with the Company's annual capital expenditures, net of the amount recovered in base distribution rates through depreciation expense. D.P.U. 09-39, at 79, 82.[50] The Department also established an investment cap, which limited the amount of capital spending the Company could recover through the CIRM to an annual investment of $170 million. D.P.U. 09-39, at 82.[51]

49 The Department addresses excess deferred income taxes in Section V., below.

50 The initial capital investment recovery mechanism was referred to as the CapEx mechanism. D.P.U. 09-39, at 12. In D.P.U. 15-155, the name of the mechanism was changed to CIRM but CapEx was maintained as the name of the factors. D.P.U. 15-155, M.D.P.U. No. 1303.

51 While the Department limited the Company's allowed recovery under the CIRM to an annual investment of $170 million, we made no determination on how much capital investment the Company should make. D.P.U. 09-39, at 82-83. The Department found that if National Grid's capital expenditures exceeded the amount it could

Subsequently, in D.P.U. 15-155, the Department increased the investment cap to an annual investment of $249 million. D.P.U. 15-155, at 56.

Pursuant to D.P.U. 09-39, at 85, the Company files a capital investment report ("CIRM filing") by July 1st of each year containing information and project documentation relating to the capital placed in service during the prior calendar year. Pursuant to D.P.U. 15-155, at 87, and the Company's CIRM tariff, M.D.P.U. No. 1303, at 2, the Company also files, by January 15th of the following year, its capital expenditures ("CapEx") factors that incorporate the costs associated with the capital placed in service, up to the allowed investment cap, into a rate adjustment effective March 1st of the same year.

From 2016 through 2018, National Grid made three CIRM filings and proposed annual CapEx factors to recover capital additions made between July 1, 2015, and December 31, 2017, up to the allowed cap. The Company's annual CIRM filings were docketed as Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 16-91 (July 1, 2015, through December 31, 2015, additions) (decision issued April 19, 2018), Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 17-110 (calendar year 2016 additions) (decision issued December 19, 2018), and Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 18-46 (calendar year 2017 additions) (pending). The Department previously found that costs for projects between July 1, 2015, and December 31, 2016, were prudently incurred and the resulting plant was used and

---

recover through its CIRM, the Company could seek to include such investment in rate base in its next base distribution rate proceeding. D.P.U. 09-39, at 82-83.

useful. D.P.U. 16-91-A at 1, 17; D.P.U. 17-110-A at 1, 17. Thus, in this case, National Grid seeks a determination of the prudence and used and usefulness of the capital additions that were the subject of D.P.U. 18-46 (i.e., the CIRM filing for investments made during calendar year 2017) plus any capital additions made between July 1, 2015, and December 31, 2017, that exceeded the applicable investment caps in each calendar year, in order for those additions to be included in rate base (Exh. NG-PCE-1, at 11).[52] Additionally, National Grid proposed that the Department approve the "rolling in" of these CIRM investments to rate base as well as approve the associated ratemaking treatment (Exh. NG-RRP-1, at 94-96).

Specifically, the Company proposed to include the CIRM investments recorded as in service between July 1, 2015, and December 31, 2017, in rate base in this case (Exh. NG-PCE-1, at 11). The Company proposed to recover through the CapEx factors revenue requirements associated with the time period between the end of the test year, i.e., December 31, 2017, and the beginning of the rate year, i.e., October 1, 2019 (Exh. NG-RRP-1, at 95-96). To prevent double recovery of these investments through the CapEx factors and base distribution rates, the Company proposed an adjustment to rate base to reflect this collection (Exh. NG-RRP-1, at 95-96). Specifically, the Company proposed to roll forward the depreciation and ADIT on the CIRM investments to reflect a September 30, 2019, rather than December 31, 2017, net plant balance for CIRM investments

52 Because the Company seeks review of the same capital additions in both D.P.U. 18-46 and the instant proceeding, the Department has suspended the procedural schedule for D.P.U. 18-46, pending the outcome of this proceeding. D.P.U. 18-46, Notice of Suspension of Procedural Schedule (March 11, 2019).

(Exh. NG-RRP-1, at 95-97). The effect of such adjustments was a reduction to National Grid's rate base of $26,843,103[53] (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 3). Of note, CIRM investments that exceeded the investment cap and, thus, were not included for recovery through the CapEx factors, are not subject to this proposed rate base adjustment and reflect a December 31, 2017, net plant balance.

2. Investment Activity

From July 1, 2015, though December 31, 2017, National Grid completed $666,765,966 in plant additions and incurred $61,642,590 in cost of removal, which resulted in an increase in utility plant of $728,408,555 (Exh. NG-PCE-1, at 6). National Grid identified 1,276 capital projects completed during this period (Exh. DPU-NG 25-7). National Grid groups its capital projects into three categories: (1) specific projects; (2) blanket projects; and (3) program or other annual projects (Exhs. NG-PCE-1, at 6; NG-PCE-2). As part of its initial filing, the Company provided the filings made in each of the previous CIRM dockets (Exh. NG-PCE-3 (CY 2015), (CY 2016), (CY 2017)). For each project the Company seeks to include in rate base, National Grid provided spreadsheets with the project number, a brief project description, the total amount authorized, the total amount expended, and the total amount closed to plant (Exh. DPU-NG 25-8, Atts. 1, 2). The Attorney General does not challenge the used and usefulness or the prudency of National Grid's capital

53 $694,152 in deferred income taxes + $26,148,950 in accumulated depreciation = total rate base reduction of $26,843,103 (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 3).

additions. No intervenor commented to the Company's instant proposal to include in rate base capital additions placed into service between July 1, 2015, and December 21, 2017.

3. Project Documentation

With exceptions noted below, the Company provided the following documentation for specific projects over $50,000 and for all blanket and program projects: (1) a project summary sheet that includes project number, project descriptions, approved amount, total to date project spending, project status, approval history, and in-service additions and cost of removal figures; (2) a project approval report showing approval amounts and dates and screen-prints from the PowerPlan system;[54] (3) documentation relating to the approved amounts (such as walk-in documents, re-approval forms, distribution capital investment group papers, United States Sanctioning Committee sanction paper, and study documents); (4) a retirement report showing any retirements related to the project in the relevant year; (5) a direct/indirect summary report for in-service additions showing project-level costs for property placed in service during the relevant year; (6) a work order asset addition report showing closings to plant in service; and (7) a project cost summary showing project spending for a given year (see, e.g., Exh. NG-PCE-3 (CY 2015), (CY 2016), (CY 2017)). For blanket and program projects, the Company also provided a fiscal year variance analysis

[54] The PowerPlan system is a project and asset reporting subledger system that National Grid began using in November 2012 (Exh. NG-PCE-3 (CY 2015), at 33).

report and a fiscal year closure paper (Exh. NG-PCE-3 (CY 2015), (CY 2016), (CY 2017)).[55] No intervenor commented on the Company's project documentation.

4. Positions of the Parties

National Grid argues that it has properly supported the net plant in service through December 31, 2017, with actual computations and thousands of pages of supporting documentation (Company Brief at 277, citing Exhs. NG-PCE-3 (CY 2015), (CY 2016), (CY 2017); NG-PCE-4). The Company explains that the supporting documentation includes project cover sheets, approved amounts, actual costs, cost variance information, project sanction, re-sanction, and closure papers (Company Brief at 277, citing Exh. NG-PCE-1, at 8-9). Thus, National Grid maintains that the record demonstrates that the Company's capital additions submitted for approval in this case, including specific projects, blanket projects, and program projects, are prudently incurred and used and useful in providing service to customers (Company Brief at 277-278). Additionally, the Company argues that its capital budgeting and authorization process assures cost containment (Company Brief at 279, citing Exh. NG-PCE-1, at 9-10). National Grid purports that its capital investment reports, submitted in this case, outline cost containment mechanisms in place to ensure cost control with capital additions (Company Brief at 279, citing Exh. NG-PCE-3 (CY 2015), (CY 2016), (CY 2017)). Thus, National Grid contends that its capital projects through December 31,

55 National Grid uses a fiscal year of April 1 through March 31 (Exh. NG-RRP-1, at 20, 123).

2017, should be included in rate base (Company Brief at 282). No intervenor commented on these issues on brief.

5. 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 a return. D.P.U. 85-270, at 25-27.

A prudence review involves a determination of whether the utility's actions, based on all that the utility knew or should have known at that time, were reasonable and prudent in light of the extant circumstances. Such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the Department merely to substitute its own judgment for the judgments made by the management of the utility. Attorney General v. Department of Public Utilities, 390 Mass. 208, 229-230 (1983). A prudence review must be based on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known, or reasonably should have been known, at the time a decision was made. Boston Gas Company, D.P.U. 93-60, at 24-25 (1993); D.P.U. 85-270, at 22-23; Boston Edison Company, D.P.U. 906, at 165 (1982). A review of the prudence of a company's actions is not dependent upon whether budget estimates later proved to be accurate but rather upon whether the assumptions made were reasonable, given the facts that were known or that should have been known at the time. 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; The Berkshire Gas Company, D.P.U. 92-110, at 24 (1993); see also 376 Mass. 294, 304; Metropolitan District Commission v. Department of Public Utilities, 352 Mass. 18, 24 (1967).[56] In addition, the Department 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.

6. Analysis and Findings

The Company reported a total of $666,765,966 in rate base additions and $61,642,590 in cost of removal for a combined capital investment total of $728,408,555 from July 1, 2015, through December 31, 2017 (Exhs. NG-PCE-1, at 6; NG-PCE-2, at 1, 61; NG-PCE-3

---

[56] The burden of proof is the duty imposed on a proponent of a fact whose case requires proof of that fact to persuade the fact finder that the fact exists, or where a demonstration of non-existence is required, to persuade the fact finder of the non-existence of that fact. D.T.E. 03-40, at 52 n.31, citing D.T.E. 01-56-A at 16; Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 7 (2001).

(CY 2015), (CY 2016), (CY 2017); DPU-NG 25-7). As noted above, National Grid groups its capital projects into three categories: (1) specific projects; (2) blanket projects; and (3) program or other annual projects (Exhs. NG-PCE-1, at 6; NG-PCE-2). National Grid reported 1,165 specific projects for $375,530,691; 64 blanket projects for $221,035,588; and 47 program projects for $70,199,686 (Exhs. NG-PCE-3 (CY 2015), (CY 2016), (CY 2017); DPU-NG 25-7).

In support of its capital additions, the Company provided a summary spreadsheet of all projects placed into service between July 1, 2015, and December 31, 2017, categorized by project number, project type, description, and plant in service and cost of removal dollars by calendar year (Exh. NG-PCE-2). Additionally, National Grid provided documentation supporting project sanctions, re-sanctions, closure papers, and variance analyses (Exhs. NG-PCE-2; NG-PCE-3 (CY 2015), (CY 2016), (CY 2017)). Finally, National Grid responded to several Department information requests seeking more information on and clarification of the supporting documentation (see, e.g., Exhs. DPU-NG 25-9; DPU-NG 25-12; DPU-NG 25-20; DPU-NG 25-23).

National Grid maintains a written delegation of authority, policy, and written sanctioning procedures for specific, blanket, and program projects (Exhs. AG 13-28 & Atts.; AG 13-29, Att.). The Company also provides explanations of the procedures and paperwork required for projects (Exh. NG-PCE-3 (CY 2015), at 34-48). Costs and spending for specific projects are approved at the outset of project implementation and during construction of the specific project through the re-authorization process, if necessary (Exh. NG-PCE-3

(CY 2015), at 23). Specific projects are initially authorized with either an investment grade or conceptual estimate following preliminary engineering (Exh. NG-PCE-3 (CY 2015), at 26). Reauthorization is required if the project cost is expected to exceed the estimate plus an approved tolerance (Exh. NG-PCE-3 (CY 2015), at 26-27). In contrast, costs and spending for blanket and program projects are approved by fiscal year (Exh. NG-PCE-3 (CY 2015), at 23). Reauthorization is generally not required for blanket and program projects if the forecast is trending towards exceeding the approved amount (Exh. NG-PCE-3 (CY 2015), at 42). Rather, the closure paper will note reasons for over-spend within categories, and the Company will adjust estimation and spending processes accordingly (Exh. NG-PCE-3 (CY 2015), at 42-43).

In managing projects, a project or program manager manages and balances both project cost and project schedule, within a total project cost (Exh. NG-PCE-3 (CY 2015), at 22). Additionally, the resource planning group monitors projects monthly against authorized levels (Exh. NG-PCE-3 (CY 2015), at 27). For specific projects, National Grid provides an explanation of variances between approved spending and total spending to date for those specific projects with spending variances greater than twenty percent (Exh. NG-PCE-3 (CY 2015), at 23, 25). For blanket and program projects, National Grid provides an explanation of variances between approved fiscal year spending and actual fiscal year spending (Exh. NG-PCE-3 (CY 2015), at 24).

Based on the review of National Grid's project authorization policies, the Department determines that National Grid's project authorization and review policies are appropriate.

Additionally, the Department finds that the Company has provided sufficient and reviewable evidence demonstrating that it has controlled costs. The Department has also reviewed the documentation provided for the projects National Grid proposes to include in rate base, and we find that the project costs were prudently incurred and that the projects are used and useful. Therefore, the Department will include the Company's proposed capital additions placed in service between July 1, 2015, and December 31, 2017, in rate base. In addition, the Department accepts the Company's proposal to adjust rate base to reflect a September 30, 2019, rather than December 31, 2017, net plant balance for CIRM investments placed into service between July 1, 2015, and December 31, 2017.

C. Prepayments

1. Introduction

As of the end of the test year, National Grid recorded $1,445,404 in prepayments, including expenses related to energy efficiency, life insurance, rent, lease, property taxes, and Department assessments (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 1, 5). National Grid proposed to include a 13-month average of prepayments in rate base, equal to $2,088,555, composed of the monthly balances of prepayments from December 2016 through December 2017 (Exhs. NG-RRP-1, at 94; NG-RRP-2 (Rev. 4), Sch. 11, at 1, 5; DPU-NG 17-26). Thus, the Company proposed an adjustment of $643,151 to rate base (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 5).

2. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should continue its well-established precedent and deny the Company's request to include prepayments in rate base (Attorney General Brief at 18-19, citing D.P.U. 10-55, at 212-213; D.P.U. 93-60, at 60; Boston Gas Company, D.P.U. 88-67 (Phase I) at 62–63 (1988); Western Massachusetts Electric Company, D.P.U. 84-25, at 60–61 (1984); Attorney General Reply Brief at 5). The Attorney General also asserts that the Company was unable to cite to any precedent since 1984 where the Department has allowed the inclusion of prepayments in rate base (Attorney General Reply Brief at 4, citing Company Brief at 160-164).

The Attorney General asserts that the Department should deny the request for several additional reasons (Attorney General Brief at 17). First, the Attorney General maintains that customers already pay for the cash working capital associated with each of the expenses included in the prepayment balance (Attorney General Brief at 17, citing Exh. NG-RRP-3 (Rev. 2), at 2a; Tr. 15, at 1818-1819). Second, the Attorney General purports that National Grid did not demonstrate that all prepayments are necessary and provide benefits to customers (Attorney General Brief at 17, citing Tr. 9, at 1300-1301). Third, the Attorney General contends that, if granted prepayments, National Grid will be charging customers twice for energy efficiency expenses because the Company already has separate, fully reconciling charges to recover energy efficiency costs (Attorney General Brief at 17, citing Tr. 9, at 1313-1314). Finally, according to the Attorney General, granting prepayments would create an imbalance in rate base by allowing the Company to add expenses that are prepaid but not subtract expenses that involve a delay in payment, including reserves for general liability, auto claims, and worker's compensation claims (Attorney General Brief at 17-18, citing Exh. AG 1-63). Thus, the Attorney General argues that the Department should deny the Company's request to include prepayments in rate base and reduce the Company's rate base by $2,088,555 (Attorney General Brief at 18-19). Alternatively, the Attorney General proffers that, if the Department allows the Company to include prepayments in rate base, the Department should also require the Company to deduct the test-year-end balances of insurance reserves, equal to $9,193,269, from rate base to maintain a balanced ratemaking treatment (Attorney General Brief at 18, citing Tr. 9, at 1302-1303; Attorney General Reply Brief at 4-5).

b. Company

National Grid contends that its prepayments, associated with energy efficiency, life insurance, rent, lease, property tax, and Department assessment expenses, are properly included in rate base (Company Brief at 161-163). National Grid explains that it has met the Department's two-part standard of review for the inclusion of prepayments in rate base (Company Brief at 161, citing D.P.U. 88-67 (Phase I) at 62; D.P.U. 84-25, at 60-61; Essex County Gas Company, D.P.U. 87-59, at 25 (1987)).

The Company argues that, in compliance with the standard of review, it has demonstrated that its lead-lag study does not include prepayments associated with energy efficiency programs, life insurance, rent, lease, or Department assessments (Company Brief at 163, citing Exhs. DPU-NG 17-23; DPU-NG 17-24; AG 3-6; Tr. 15, at 1814; RR-DPU-35). The Company notes that, while the lead-lag study does reflect property tax payments before the midpoint of the service period, the Company's prepaid property tax balances relate only to the portion of property tax assessments paid over the amount incurred during the applicable tax period (Company Brief at 163, citing Exhs. DPU-NG 17-24; DPU-NG 17-28). Thus, National Grid claims that the Attorney General's allegation that it will be double-recovering prepayment costs through cash working capital is incorrect and should be disregarded (Company Brief at 163).

The Company also contends that, in compliance with the standard of review, it has demonstrated that its prepayments provide benefits to customers (Company Brief at 161, citing Exh. NG-RRP-Rebuttal-1, at 13-15; RR-DPU-35). National Grid maintains that, because there are numerous calls on the Company's financial resources, the decision to prepay an expense at all indicates that there was a benefit to be gained by doing so (Company Brief at 161, citing RR-DPU-35). Additionally, National Grid claims that energy efficiency prepayments yield benefits to customers because the Company procures the most advantageous agreements by agreeing to prepay these expenses (Company Brief at 162, citing Exh. DPU-NG 17-30; Tr. 15, at 1796-1798). The Company adds that the separate reconciling mechanism only recovers program expenses and does not recover prepaid cash amounts, contrary to the Attorney General's accusation that the Company is double recovering these expenses (Company Brief at 162-163). National Grid continues that prepaying life insurance, rent, and lease expenses benefits customers because it prevents the customers from being charged vendors' implicitly or explicitly added carrying costs associated with anticipated collection lag (Company Brief at 161-162, citing RR-DPU-35). According to the Company, prepayments of Department assessments benefit customers because the Department gains access to the funds, which are used to regulate the operations of the Company and other utilities, earlier (Company Brief at 161, citing RR-DPU-35). Finally, National Grid contends that prepaying property taxes prevents customers from paying penalties and interest payments that are assessed if the payment is not received in advance of the due date (Company Brief at 162, citing RR-DPU-35).

In response to the Attorney General's claim that the Company does not subtract insurance reserves, National Grid maintains that there is record evidence to the contrary (Company Brief at 163, citing Tr. 15, at 1306). National Grid asserts that it does not include these items in rate base, and it only receives compensation from customers through rates on a cash basis, after claims are made (Company Brief at 164). Thus, the Company requests that the Department disregard the Attorney General's recommendation (Company Brief at 164).

3. Analysis and Findings

The Department has previously found that, in the absence of evidence that prepayments provide benefits to ratepayers, they are to be excluded from rate base because they are but one of a myriad of positive and negative offsets that are recognized in a company's cash working capital allowance. D.P.U. 10-55, at 212-213; D.P.U. 93-60, at 60; D.P.U. 88-67 (Phase I) at 62-63; D.P.U. 84-25, at 60-61. The Department has also stated that, should a company wish to include prepayments as a separate rate base item, it should also file a full lead-lag study that specifically excludes prepayments. D.P.U. 88-67 (Phase I) at 62-63. Therefore, we will evaluate National Grid's proposal to include prepayments in rate base by first determining whether the Company (1) excluded prepayments from its lead-lag study and (2) demonstrated that the prepayments yield direct benefits to ratepayers. First, however, we will address energy efficiency prepayments separately.

Of the $2,088,555 proposed prepaid balance, energy efficiency prepayments account for $1,793,023 (see Exh. DPU-NG 17-28, Att.).[57] An Act Relative to Green Communities, St. 2008, c. 169, specifies that energy efficiency-related costs must be collected through a fully reconciling mechanism, and the Department has approved the energy efficiency surcharge for this purpose. G.L. c. 25, §§ 19(a), 21(b)(2)(vii); D.P.U. 08-50-B, Guidelines, Section 2.9, 3.2.1; D.P.U. 15-155, at 143 & M.D.P.U. 1340. The Company acknowledges that the energy efficiency recovery factor recovers National Grid's energy efficiency expenses (Tr. 7, at 975-976). National Grid, however, states that the mechanism does not allow the Company to recover costs until they are expensed, and, as such, prepaid expenses are appropriately included in base distribution rates (Tr. 7, at 975-976). The Department disagrees. The Department has repeatedly found that costs that have their own reconciling mechanism should be excluded from base distribution rates. D.P.U. 15-155, at 143-144; D.P.U. 88-67 (Phase I) at 77-78; D.P.U. 87-59, at 6. Accordingly, the Department

57 Taking the 13-month average of the prepaid services – energy efficiency balances listed in Exhibit DPU-NG 17-28 yields $1,793,023.

disallows the inclusion of the energy efficiency prepayment in rate base and reduces the Company's rate base by $1,793,023.

Turning to the other proposed prepayments, National Grid provided detailed discovery responses and oral testimony supporting the computation of its lead-lag study (Exhs. DPU-NG 17-23; DPU-NG 17-24; DPU-NG 17-25; Tr. 7, at 977-978). The Company explicitly excluded prepayments related to energy efficiency, insurance, rent, lease, and Department assessments (Exhs. DPU-NG 17-23; DPU-NG 17-24; DPU-NG 17-25; Tr. 7, at 977-980). Although the lead-lag study does reflect some property tax payments before the midpoint of the service period, the prepaid balance for which the Company requests recovery only relates to the portion of property tax assessments paid above and beyond the amount incurred during the applicable tax period (Exh. DPU-NG 17-24). Accordingly, the Department is satisfied that the Company has excluded prepayments from the lead-lag study.

Next, we evaluate whether the Company has demonstrated direct ratepayer benefits from each of the following prepayment categories: insurance; rent; lease expense; property taxes; and Department assessments. Regarding insurance, rent, and lease expense, the Company testified that some vendors might require prepayment for their services (Tr. 15, at 1801). Additionally, the Company offered that prepaying the expenses may result in the vendor waiving implicit or explicit carrying costs associated with anticipated collection lag, but the Company did not provide the Department with a quantification of those savings (RR-DPU-35). The Department has previously found that while prepayments may be a requirement of a particular vendor, it is difficult to ascertain the benefit to ratepayers.

D.P.U. 87-59, at 25. As such, the possibility that National Grid's insurance, rent, and lease expense vendors may require prepayments is irrelevant to the instant question of whether the prepayments yield direct ratepayer benefits. Given that National Grid did not provide a quantification of the savings that may or may not occur with the prepayments, the Department finds that the Company has not demonstrated direct ratepayer benefits. In the absence of evidence that accurately represents the benefit that ratepayers receive from a prepayment, we find that the Company's proposed inclusion of insurance, rent, and lease expense prepayments in rate base must be disallowed. D.P.U. 87-59, at 25; D.P.U. 84-25, at 60-61. Of the $2,088,555 proposed prepaid balance, insurance, rent, and lease expense prepayments account for $220,035 (see Exh. DPU-NG 17-28).[58] Accordingly, the Department reduces the Company's rate base by $220,035.

Regarding property taxes, National Grid offered that it commonly takes an extended period of time for payments to be recorded by respective municipalities, and prepaying avoids potential penalties that are assessed if the payment is not received in advance of the due date (RR-DPU-35). Again, the Department finds that the Company's provision of un-quantified, potential penalties is not a sufficient demonstration of direct ratepayer benefits. D.P.U. 87-59, at 25; D.P.U. 84-25, at 60-61. Of the $2,088,555 proposed prepaid balance,

58 Taking the sum of each of the thirteen-month averages of the prepaid life insurance, prepaid rent, and prepaid long-term lease balances listed in Exhibit DPU-NG 17-28 yields $220,035.

property tax expense prepayments account for $2,795 (see Exh. DPU-NG 17-28).[59] Accordingly, the Department reduces the Company's rate base by $2,795.

Regarding Department assessments, National Grid explained that the amount of the assessment levied on the Company does not change with prepayment (RR-DPU-35). As such, the Department finds that the Company has not demonstrated direct ratepayer benefits from prepaying Department assessment expenses and disallows their proposed inclusion in rate base. Of the $2,088,555 proposed prepaid balance, Department assessment prepayments account for $72,702 (see Exh. DPU-NG 17-28).[60] Accordingly, the Department reduces the Company's rate base by $72,702.

In conclusion, the Department reduces National Grid's rate base by $2,088,555 related to prepayments. Because the Department has excluded prepayments from rate base, it is necessary to re-introduce these items to the cash working capital calculations to ensure National Grid is adequately compensated for the use of its funds. The adjustment to cash working capital will be addressed in Section III.D.3., below.

D. Cash Working Capital Allowance

1. Introduction

In their day-to-day operations, utilities require funds to pay for expenses incurred in the course of business, including O&M expenses. These funds are generated internally by a

---

59 Taking the 13-month average of the prepaid property tax balances listed in Exhibit DPU-NG 17-28 yields $2,795.

60 Taking the 13-month average of the prepaid Department assessment balance listed in Exhibit DPU-NG 17-28 yields $72,702.

company or through short-term borrowing. 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, citing Western Massachusetts Electric Company, D.P.U. 87-260, at 22-23 (1988). This reimbursement is accomplished by adding a cash working capital component to the rate base calculation.

Cash working capital costs have been determined through either the use of a lead-lag study or a conventional 45-day O&M expense allowance. D.T.E. 03-40, at 92. In the absence of a lead-lag study, the Department has previously relied on a 45-day convention as reasonably representative of O&M working capital requirements. D.T.E. 05-27, at 98; D.P.U. 88-67 (Phase I) at 35.[61] The Department has expressed concern that the 45-day convention, first developed in the early part of the 20th century, may no longer provide a reliable measure of a utility's working capital requirements. D.T.E. 03-40, at 92, citing Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 15 (1998); D.P.U. 96-50 (Phase I) at 27. In recent years lead-lag studies have resulted in savings for ratepayers by reducing the cash working capital requirement below the 45-day convention. Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 163 (2011), citing New England Gas Company, D.P.U. 10-114, at 108 (2011); D.P.U. 10-70, at 78; D.P.U. 10-55, at 204-205; D.P.U. 09-39, at 114; D.P.U. 09-30, at 151-152; New England Gas Company,

---

61 When a fully developed and reliable lead-lag study is not available, FERC applies a 45-day convention to determine the cash working capital allowance. Carolina Power and Light Company, 6 FERC ¶ 61,154, P 61, 296 (1979). As a result, companies occasionally refer to the 45-day convention as the "FERC convention." Fitchburg Gas and Electric Light Company, D.P.U. 11-01/D.P.U. 11-02, at 150 n.81 (2011).

D.P.U. 08-35, at 38 (2009); D.T.E. 05-27, at 99-100. For those reasons, 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.

National Grid conducted a lead-lag study to determine its cash working capital requirements (Exhs. NG-RRP-1, at 95, 105; NG-RRP-3). Consistent with the lead-lag study conducted in D.P.U. 09-39, at 108, the cash working capital associated with purchased power expense will be recovered through the Company's basic service cost adjustment provision, and the cash working capital associated with other operating expenses will be recovered through inclusion in the Company's rate base (Exhs. NG-RRP-1, at 74; NG-RRP-3). The Company initially proposed a cash working capital allowance for other operating expenses of $71,478,512 using a net lead-lag factor of 6.83 percent, or 24.93 days (Exhs. NG-RRP-1, at 105-106; NG-RRP-3, at 1; DPU-NG 17-35, Att.).[62] Throughout the course of the proceeding, the Company updated its proposed cash working capital allowance to account for changes in its operating expenses and municipal taxes (Exh. NG-RRP-3 (Rev. 4)). The Company ultimately proposed a cash working capital allowance of $70,006,225, using a net lead-lag factor of 6.78 percent, or 24.75 days (Exhs. NG-RRP-3 (Rev. 4), at 1; NG-RRP-5 (Rev. 4), at 7).[63]

---

62 The Company reported a total distribution working capital requirement of $71,478,512 from a total dollar amount of $1,046,832,162 resulting in a cash working capital factor of 6.83 percent, which equates to 24.93 days (6.83 percent * 365 days in a year) (Exh. NG-RRP-3, at 1).

63 The Company reported a total distribution working capital requirement of $70,006,225 from a total dollar amount of $1,032,904,596 resulting in a cash working

To determine its proposed cash working capital allowance, National Grid first identified the following expense categories: (1) purchased power expense; (2) contract termination charges;[64] (3) O&M expense; (4) transmission expense; (5) municipal taxes; (6) federal unemployment taxes; (7) state unemployment taxes; (8) Federal Insurance Contributions Act ("FICA") expense (both weekly and monthly);[65] (9) FICA and federal withholding (weekly and monthly); (10) state income tax withholding (weekly and monthly); and (11) incentive thrift (weekly and monthly)[66] (Exhs. NG-RRP-1, at 105-106; NG-RRP-3 (Rev. 4), at 1). The Company then determined a dollar-weighted period of time between the end date for the receipt of service from the supplier and the payment date, producing expense

---

capital factor of 6.78 percent, which equates to 24.75 days (6.78 percent * 365 days in a year) (Exh. NG-RRP-3 (Rev. 4), at 1).

64 The contract termination charges resulted from a FERC-approved wholesale settlement that restructured the wholesale contractual relationship between New England Power Company and MECo in the context of restructuring the electric utility industry in Massachusetts. New England Power Company terminated its all-requirements contractual agreement with MECo in exchange for the payment of contract termination charges by MECo. New England Power Company, FERC Docket Nos. ER97-678-000 (1997) and ER98-6-000 (1998); New England Power Company/Massachusetts Electric Company/Nantucket Electric Company, D.P.U./D.T.E. 97-94, at 11 (1998).

65 Under FICA, an employer withholds three separate taxes from employees' wages: (1) Social Security tax; (2) Medicare tax; and (3) Medicare surtax. 26 U.S.C. Chapter 21. FICA also requires that the employer pay a matching employer share of (1) Social Security tax and (2) Medicare tax. 26 U.S.C. Chapter 21.

66 The incentive thrift plan expense adjustment relates to the cost charged to O&M for the employer's match for employee 401(k) plan contributions (Exh. NG-RRP-1, at 32). The 401(k) plan matching contribution applies to the Company's employees, and to NGSC and other affiliated company employees who charge time to the Company (Exh. NG-RRP-1, at 32).

lag factors as a percentage of total days in a calendar year ranging between a negative 3.42 percent for municipal taxes and 23.01 percent for federal unemployment tax (Exhs. NG-RRP-1, at 105-106; NG-RRP-3 (Rev. 4), at 13, 14).

Next, National Grid developed separate revenue lags for MECo and Nantucket Electric representing the time delay between the mailing of customers' bills and the receipt of the billed revenues from customers (Exhs. NG-RRP-1, at 105-106; NG-RRP-3 (Rev. 4), at 3, 26). The revenue lags were obtained by first averaging the twelve-month balances of accounts receivable and then dividing the result by the average monthly electric revenues, producing collection lag components of 32.28 days associated with MECo and 23.20 days associated with Nantucket Electric (Exhs. NG-RRP-1, at 105-106; NG-RRP-3 (Rev. 4), at 3, 26). National Grid then added a billing lag of 1.41 days, representing the average lag from the date a meter is read for the customer's electric usage to the date the bill is sent to the customer (Exhs. NG-RRP-1, at 105-106; NG-RRP-3 (Rev. 4), at 3, 26). The Company also added a service lag of 15.21 days, representing the average lag from the date between the mid-point of the service period and the meter reading date for that service period (Exhs. NG-RRP-3 (Rev. 4), at 3, 26; DPU-NG 16-15; DPU-NG 25-3). The sums of the collection lags, billing lags, and service lags, represented as a percentage of the number of days in a calendar year, are 13.40 percent for MECo's overall expenses and 10.91 percent for Nantucket Electric's overall expenses (Exh. NG-RRP-3 (Rev. 4), at 3, 26).

National Grid then subtracted the respective expense lag factors determined above from their respective revenue lag factors and then blended the results for MECo and

Nantucket, producing consolidated cash working capital factors for each expense category ranging between a negative 9.61 percent for federal unemployment taxes and 16.82 percent for municipal taxes (Exh. NG-RRP-3 (Rev. 4), at 1-2b). These cash working capital factors were then multiplied by the pro forma expense associated with these expense categories, producing a total cash working capital allowance associated with operating expenses other than purchased power and contract termination charges of $30,813,863 (Exh. NG-RRP-3 (Rev. 4), at 1). The Company repeated this process for transmission expenses, incentive thrift, and tax expenses and summed these individual cash working capital allowances to arrive at its final requested cash working capital allowance of $70,006,225 (Exh. NG-RRP-3 (Rev. 4), at 1).

2. Positions of the Parties

a. Attorney General

The Attorney General contends that the Company's lead-lag study overstates the cash working capital allowance (Attorney General Brief at 15). Specifically, the Attorney General argues that the Company has inappropriately included the hardship accounts regulatory asset in the monthly balance of accounts receivable that it uses to determine the revenue lag portion of its net lag factor (Attorney General Brief at 15, citing Exh. NG-RRP-3). According to the Attorney General, the Department previously granted the Company amortization of its hardship protected accounts receivable (Attorney General Brief at 15, citing D.P.U. 15-155, at 249-252). The Attorney General also purports that the Department has determined that non-cash items such as depreciation and amortizations should not be included in the working capital allowance (Attorney General Brief at 15, citing Nantucket Electric Company, D.P.U. 91-106/91-138-B at 5-6 (1992); Western Massachusetts Electric Company, D.P.U. 88-250, at 20, 196 (1989)). Since the hardship protected accounts are now a regulatory asset that is being recovered through an amortization, the Attorney General argues that these costs should be excluded from the monthly accounts receivable balance used to calculate the revenue lag (Attorney General Brief at 15).

The Attorney General alleges that National Grid's new position that its initial filing excludes these accounts, provided after the close of evidentiary hearings, is not sufficient (Attorney General Reply Brief at 7, citing Company Brief at 168-169, citing Exhs. DPU-NG 17-32 (Supp.); DPU-NG 17-33 (Supp.); RR-AG-19 (Supp.)). The Attorney General argues that the Company's contradictory statements call into question the validity of its new position (Attorney General Reply Brief at 7). In particular, the Attorney General points out that, with the Company's new position, National Grid simultaneously asserts (1) that removing the hardship protected accounts would be inappropriate, and (2) that its lead-lag study effectively eliminates hardship protected accounts (Attorney General Reply Brief at 7, citing Company Brief at 168). Additionally, the Attorney General posits that National Grid cannot simultaneously claim that the hardship protected accounts included in the study are "fully offset" by the credit amount in Account 144[67] and that the amounts in

---

67 The FERC system of accounts applicable to electric utilities are set forth at 18 CFR Subchapter C, Part 101, "System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act." Account 144 is "accumulated provision for uncollectible accounts – credit."

Account 144 are "estimates" of customer accounts receivable that will not be collected (Attorney General Reply Brief at 7). Rather, the Attorney General maintains that National Grid provided the lead-lag study removing the hardship protected accounts in response to a record request (Attorney General Brief at 15-16, citing RR-AG-19, Att. 2). Accordingly, the Attorney General recommends that the Department reject National Grid's proposed lead-lag study that includes the hardship protected accounts and instead use the lead-lag study provided in response to her record request (Attorney General Brief at 15, citing RR-AG-19, Att. 2; Attorney General Reply Brief at 6).

b. Company

National Grid contends that it did not make any adjustment to its lead-lag study to account for the recovery of hardship protected accounts receivable aged greater than 360 days (Company Brief at 166, citing Exh. NG-RRP-1, at 106). The Company asserts that it did not make any adjustment because the recovery of a cash working capital allowance and historic balances of hardship protected accounts receivable serve distinct ratemaking purposes (Company Brief at 1, 66, citing Exhs. NG-RRP-1, at 106; DPU-NG 17-32; DPU-NG 17-32 (Supp.)). National Grid maintains that the cash working capital allowance, which includes a revenue lag measured using historical data, compensates the Company for the "float" that it must fund on a day-to-day basis,[68] while the amortization of test-year hardship accounts receivables aged greater than 360 days provides recovery of historical amounts that have no

68 In this context, "float" generally means the delays by a bank in processing checks between receipt and funds clearance in the account.

other cost of service mechanism by which to be recovered (Company Brief at 166-167). National Grid contends that the amortization of hardship protected accounts receivable does not alter the relationship between sales and the accrual and eventual payment of accounts receivable related to sales (Company Brief at 167, citing Exh. DPU-NG 17-32).

In response to the Attorney General, National Grid offers that, in addition to the two categories having distinct ratemaking purposes, the Company employs the same billing and collection practices for hardship protected accounts as it does all other customer accounts (Company Brief at 167-168, citing Tr. 15, at 1804, 1807). The Company, therefore, contends that removing the hardship protected accounts would make the revenue lag calculation, and the resulting cash working capital allowance, unrepresentative of the actual and necessary cash working capital allowance (Company Brief at 168, citing Tr. 15, at 1804, 1807). Additionally, National Grid alleges that it uses the monthly balances of accounts receivable in Account 142,[69] net of the monthly balance of the accumulated provision for uncollectible accounts-credit in Account 144 to arrive at the accounts receivable balance used in its lead-lag study, thus, effectively eliminating the hardship protected accounts receivables to which the Attorney General objects (Company Brief at 168-169, citing Exhs. DPU-NG 17-32 (Supp.); DPU-NG 17-33 (Supp.); RR-AG-19 (Supp.); Company Reply Brief at 86). National Grid contends that the Attorney General's recommendation would result in an inconsistent and unrealistic calculation of the revenue lag and the cash working

[69] Under the applicable FERC Uniform System of Accounts, Account 142 is "customer accounts receivable."

capital allowance and that the Department should reject it (Company Brief at 169-170; Company Reply Brief at 86-87).

3. Analysis and Findings

The Attorney General argues that the Department should adjust the Company's cash working capital allowance to remove any recovery of hardship protected accounts receivable balance aged greater than 360 days. The Attorney General made a similar argument in the Company's previous base distribution rate case. D.P.U. 15-155, at 140-141. In that case, the Department approved the Company's proposal to amortize the test-year balance of hardship protected accounts aged greater than 360 days. D.P.U. 15-155, at 143, 250-251. The Department determined that there was no need to recalculate the revenue lag because, to the extent that the amortization recovery might affect the revenue lag, any changes would be incorporated in future cash working capital studies. D.P.U. 15-155, at 143.

National Grid explained that, to implement the approved amortization, it created a regulatory deferral and credited both revenues and the deferral each month (Exh. DPU-NG 17-34). Neither the creation of a regulatory deferral nor the crediting of the deferral and revenues accounts results in any changes to the status of hardship protected accounts, the balances of overdue payments, or the number of days the balances are past due, which are the metrics captured by the revenue lag calculation (Exh. DPU-NG 17-34). As such, absent a specific ratemaking adjustment, the process of recovering amortized hardship protected accounts receivable balances does not have any impact on the revenue lag calculations performed to arrive at the cash working capital allowance. The Department will determine now whether such a ratemaking adjustment is warranted.

The Department's standard on cash working capital is intended to allow a utility to recover legitimate working capital expense outlays that must be made while waiting for collection of revenues. D.P.U. 93-60, at 47-48. Additionally, if the cash working capital requirements are determined through a lead-lag study, all cash items are included in the lead-lag study. D.P.U. 88-250, at 18-20. The Department has held that non-cash items, such as depreciation expense, deferred income taxes, amortization, investment tax credits, and gains/losses on the sale of utility property, are not normally included in the lead-lag study. D.P.U. 88-250, at 18-20. Once an amortization is granted for hardship protected accounts receivables aged greater than 360 days, the data associated with those accounts, including the outstanding balances and the collection lags, become inextricably linked to an amortization. Further, although National Grid maintains that amortizations and the cash working capital allowance serve different regulatory purposes, the Department is not convinced that this specific amortization, which grants dollar-for-dollar recovery of balances whose data have a direct impact on the calculations that determine working capital requirements, is wholly unrelated to the Company's working capital needs. Therefore, the Department finds that companies for whom the Department has approved amortization of hardship protected accounts receivables aged greater than 360 days must also exclude all such accounts from their lead-lag studies and resulting cash working capital allowance calculations.

In accordance with the above finding, the Department seeks to derive the cash working capital allowance using a lead-lag study that excludes hardship protected accounts receivable balances aged greater than 360 days. National Grid stated for much of the proceeding that it did not adjust its lead-lag study to exclude hardship protected accounts receivable and that it would be inappropriate to do so (Exhs. NG-RRP-1, at 106-107; DPU-NG 17-32; DPU-NG 17-33; DPU-NG 17-34; Tr. 15, at 1803-1804; RR-AG-19). In investigating the propriety of including hardship protected accounts receivable balances aged greater than 360 days in the lead-lag study, the Department and the Attorney General solicited, and the Company provided, illustrative versions of the lead-lag study that excluded hardship protected accounts (Exh. DPU-NG 17-33, Att. 1; RR-AG-19, Att. 2).

In response to a Department record request, however, National Grid informed the parties that its direct testimony, information request responses, oral testimony, and previous record request responses were incorrect because its initial filing revenue lag calculation did subtract some portion of hardship protected accounts receivable data (RR-DPU-34; see also Exhs. DPU-NG 17-32 (Supp.); DPU-NG 17-33 (Supp.); RR-AG-19 (Supp.)). National Grid now represents that its proposed lead-lag study already excludes the accounts and any responses providing illustrative lead-lag studies "excluding" the accounts actually exclude them twice and, as such, should be ignored (RR-DPU-36). The Company elaborated that the accounts receivable balance included in the revenue lag calculation portion of the lead-lag study was actually a net balance of Account 142 and Account 144 (Exhs. DPU-NG 17-32 (Supp.); DPU-NG 17-33 (Supp.)). National Grid described Account 144 as the Company's best estimate of the amount of customer accounts receivable that will ultimately not be collected and asserted that the hardship protected accounts receivable balances aged greater than 360 days are among the least likely amounts that the Company will ever collect (Exhs. DPU-NG 17-32 (Supp.); DPU-NG 17-33 (Supp.)).

In attempting to verify National Grid's new position, the Department discovered differences between the lead-lag study's December 31, 2017 balances for Account 142 and Account 144 and the Company's FERC Form 1 December 31, 2017 balances for Account 142 and Account 144 (Exhs. NG-RRP-3, at 24, line 13 & 43, line 13; NG-RRP-3 (Rev. 4), at 24, line 13 & 43, line 13; WP NG-RRP-1, at 2, lines 40, 42). For example, in the lead-lag study, Account 142 has over $100 million less than is shown in FERC Form 1 (Exhs. NG-RRP-3, at 24, line 13 & 43, line 13; WP NG-RRP-1, at 2, line 40, 42).[70] The Department was unable to investigate or reconcile these differences because National Grid provided its new position after the close of evidentiary hearings (Exhs. DPU-NG 17-32 (Supp.); DPU-NG 17-33 (Supp.); RR-AG-19 (Supp.); RR-DPU-34; RR-DPU-36). Despite this circumstance, it is evident that the accounts receivable balance used in the lead-lag study removes a significant portion of accounts, likely including some or all of the hardship

---

[70] For Account 142, the lead-lag study shows $370,582,364 and $1,542,025 for MECo and Nantucket Electric, respectively, while the FERC Form 1 shows $471,885,881 and $2,159,883 for MECo and Nantucket Electric, respectively (Exhs. NG-RRP-3, at 24, line 13 & 43, line 13; NG-RRP-3 (Rev. 4), at 24, line 13 & 43, line 13; WP NG-RRP-1, at 2, lines 40, 42). For Account 144, the lead-lag study shows $140,094,666 and $174,535 for MECo and Nantucket Electric, respectively, while the FERC Form 1 shows $117,212,849 and $179,960 for MECo and Nantucket Electric, respectively (Exhs. NG-RRP-3, at 24, line 13 & 43, line 13; NG-RRP-3 (Rev. 4), at 24, line 13 & 43, line 13; WP NG-RRP-1, at 2, lines 40, 42).

protected accounts receivable balances aged greater than 360 days (Exhs. NG-RRP-3, at 24, line 13 & 43, line 13; NG-RRP-3 (Rev. 4), at 24, line 13 & 43, line 13; WP NG-RRP-1, at 2, lines 40, 42). As such, the Department accepts National Grid's proposed lead-lag study under the explicit assumption that it excludes hardship protected accounts receivable balances aged greater than 360 days. The Department directs National Grid to make a detailed demonstration that it has excluded these accounts from its lead-lag study and cash working capital calculation in the initial filing of its next base distribution rate case. The Department also notes that any company granted amortization of hardship protected accounts receivable balances aged greater than 360 days is expected to exclude these accounts from future lead-lag studies and cash working capital calculations and should include detailed documentation demonstrating this exclusion in the initial filing of its base distribution rate case.

Finally, in accordance with the Department's earlier directives to remove prepayments from rate base, the Department will make a concordant adjustment to National Grid's cash working capital allowance. Specifically, the Department will introduce prepayments to the lead-lag study. Introducing prepayments to the lead-lag study mainly affects the "Other O&M" expense lead, reducing the lead from 49.72 days to 46.69 days (RR-DPU-36). This change in the expense lead results in a Department-approved cash working capital factor of 6.83 percent (Exh. NG-RRP-3 (Rev. 4), at 1; RR-DPU-36, Att. 1). Application of the cash working capital factor of 6.83 percent to the level of O&M and taxes other than income tax expense authorized by this Order produces a cash working capital allowance of $70,171,861 for the Company, which is used to calculate the Company's revenue requirement (Exh. NG-RRP-3 (Rev. 4), at 1; RR-DPU-36, Att. 1). The derivation of this cash working capital allowance is provided in Schedule 6 of this Order.

IV. CAPITAL INVESTMENT RECOVERY MECHANISM

A. Introduction

In D.P.U. 09-39, the Department approved the first iteration of the Company's current CIRM, which was called the capital expenditure mechanism ("CapEx Mechanism"). The CapEx Mechanism allowed the Company to recover an annual revenue requirement on incremental capital investments up to a $170 million cap (hereinafter referred to as the "investment cap"). D.P.U. 09-39, at 82. Incremental capital investment for each year since the CapEx Mechanism commenced is defined as annual capital investment less the Company's depreciation expense allowed in its last base distribution rate proceeding (Exh. NG-HSG-13, Current M.D.P.U. 1303, § I (Actual Net Capital Expenditures) (Bates Stamp 180)). National Grid calculates each investment vintage year's revenue requirement using an average rate base method, incorporating accumulated depreciation and accumulated deferred income taxes ("ADIT") associated with that vintage year's investments (Exh. NG-HSG-13, Current M.D.P.U. 1303, § I (Cumulative Revenue Requirement) (Bates Stamp 180)). The CIRM does not allow for the recovery of the revenue requirement for the first year of investments for each vintage year, and the Company recovers the revenue requirement for the second year of each vintage year beginning March 1st of the subsequent year (Exh. NG-HSG-13, Current M.D.P.U. 1303, § II (CapEx Factors) (Bates Stamp 181)).

In the Company's last base distribution rate case, the Department continued National Grid's CapEx Mechanism with modifications, including changing the name to CIRM. D.P.U. 15-155, at 51-61. The Department separated the CIRM from the Company's revenue decoupling mechanism and approved a one-percent annual revenue cap on any increase to the CIRM revenue requirement. D.P.U. 15-155, at 54-55. Additionally, the Department increased the investment cap to an annual investment of $249 million and approved the inclusion of property taxes in the calculation of the CIRM revenue requirement. D.P.U. 15-155, at 56, 58-59, 61.

B. Company Proposal

If the Department approves the Company's PBR proposal, National Grid proposes only to continue the CIRM by collecting the revenue requirement on incremental capital additions placed into service in calendar years 2018, 2019, and January through September 2020 through the CIRM factors (Exh. NG-PBRP-1, at 49). National Grid proposes to apply the current annual investment cap of $249 million to the aforementioned investments (Exh. NG-PBRP-1, at 49). Additionally, the Company proposes to roll into base distribution rates all capital investments, including those above the CIRM investment cap, placed into service in calendar years 2018, 2019, and January through September 2020 as part of the PBR mechanism adjustments effective October 1, 2020, October 1, 2021, and October 1, 2022, respectively (Exh. NG-PBRP-1, at 49-50). National Grid proposes to cease recovery through the CIRM factors for the current year's revenue requirement as of October 1 each year and continue the reconciliation component of the mechanism (Exhs. NG-PBRP-1, at 50; DPU-NG 19-1, Att. 1; DPU-NG 19-4; DPU-NG 19-5; DPU-NG 19-6).

In the event that the Department denies the Company's PBR proposal or modified it to a degree that the Company could not commit to the five-year stay-out provision, National Grid proposes to continue the CIRM with modifications (Exh. NG-PBRP-1, at 51). Specifically, the Company proposes to increase the annual investment cap from the cap of $249 million to $295 million (Exhs. NG-PBRP-1, at 51; NG-PCE-1, at 12). The Company calculated the proposed investment cap using the historical average of annual capital spending for the past three years (Exh. NG-PCE-1, at 15). National Grid's proposed investment cap of $295 million reflects annual capital spending, plus the cost of removal, of $302 million in calendar year 2015, $261 million in calendar year 2016, and $321 million in calendar year 2017 (Exhs. NG-PCE-1, at 15; NG-PCE-4).

C. Positions of the Parties

1. Attorney General

The Attorney General argues that the Department should reject National Grid's proposal to continue the CIRM through the end of the rate year if it is granted a PBR mechanism because the Company will double recover costs (Attorney General Brief at 19, citing Exh. NG-PBRP-1, at 49). The Attorney General elaborates that the initial base distribution rates effective during the rate year are designed to recover incremental capital investment costs, and that the PBR rate adjustments to begin at the end of the rate year provide incremental carrying costs on the initial amount (Attorney General Brief at 19). The

Attorney General claims that allowing the Company to extend the CIRM beyond the end of the test year will allow the Company to recover incremental carrying costs incurred during the rate year through both the CIRM and the PBR mechanism revenue increase (Attorney General Brief at 20). Additionally, the Attorney General maintains that the Company's proposal to continue the CIRM during the PBR stay-out period flies in the face of the PBR mechanism's purpose and the PBR mechanism's financial incentives (Attorney General Brief at 20). Therefore, the Attorney General contends that, if the Department approves a PBR mechanism, it must also end the CIRM on October 1, 2019, which is the effective date of new base distribution rates (Attorney General Brief at 20).

The Attorney General also posits that if the Department allows National Grid to roll any post-test-year investment into base distribution rates, it also must require National Grid to recognize the depreciation that will be collected on existing assets during the same time period (Attorney General Brief at 14). The Attorney General explains that, while National Grid will incur new capital investment during the period between the test year and the end of the rate year, it also will collect depreciation expense during this period at an annual rate of approximately $140 million (Attorney General Brief at 12, citing Exh. NG-RRP-2, Sch. 6, at 1). According to the Attorney General, National Grid will collect approximately $245 million in depreciation expense between the end of the test year and the beginning of the rate year and $385 million in depreciation expense between the end of the test year and the end of the rate year (Attorney General Brief at 12). The Attorney General objects to the Company's proposal to add capital investment into rates during its PBR stay-out period without recognizing the accumulated depreciation recovery because it presents a one-sided view of capital investment (Attorney General Brief at 12). The Attorney General adds that in addition to the above depreciation collection, the process of existing assets depreciating lowers the Company's return on rate base, federal corporate income taxes, state business taxes, and municipal property taxes, but the Company does not propose to include any of these changes in rates (Attorney General Brief at 13). Thus, the Attorney General objects to National Grid's proposal to include post-test-year additions to rate base while failing to recognize post-test-year deductions from rate base (Attorney General Brief at 12-13).

In conclusion, the Attorney General recommends that, if the Department allows National Grid to roll into base distribution rates the investments made between the end of the test year and the beginning of the rate year, it should require National Grid to reduce base distribution rates by the accrued depreciation of $245 million (Attorney General Brief at 14). The Attorney General recommends that, if the Department allows National Grid to roll into base distribution rates investments made between the end of the test year and the end of the rate year, it should require National Grid to reduce base distribution rates by the accrued depreciation of $385 million (Attorney General Brief at 14).

2. Company

National Grid argues that its proposal to continue the CIRM if granted a PBR mechanism is essential to create a bridge between the transition from the CIRM to the PBR mechanism to ensure that it can make incremental investments in the distribution system to maintain safe, reliable, and efficient electric distribution service (Company Brief at 54;

Company Reply Brief at 8). The Company maintains that the proposed transition is consistent with Department precedent (Company Brief at 54; Company Reply Brief at 8). Specifically, National Grid highlights the Company's transition from the CapEx mechanism to the CIRM in D.P.U. 15-155 as well as the transition from the targeted infrastructure replacement factor ("TIRF") program to the gas system enhancement program ("GSEP")[71] to support its proposal to continue recovering through the CIRM capital additions placed into service between the end of the test year and the end of the rate year (Company Brief at 54, citing Exh. DPU-NG 13-6, at 2). Additionally, National Grid contends that it should be allowed to continue the CIRM because, were it not proposing a PBR mechanism and instead proposing to continue the CIRM, it would be allowed to recover through the CIRM capital investments placed into service after the test year (Company Brief at 54; Company Reply Brief at 8). The Company argues that, if it were prohibited from collecting the revenue requirement on capital additions made in 2018, 2019, and part of 2020, it is unlikely that the Company could or would commit to the five-year stay-out provision in its proposed PBR mechanism (Company Reply Brief at 8). According to National Grid, premature cessation of the CIRM eliminates its recovery of hundreds of millions of dollars and places pressure on the Company to file a base distribution rate case during the five-year stay-out (Company Reply Brief at 8). Therefore, the Company argues that, if the Department allows the PBR

[71] The TIRF and GSEP are programs managed by the Company's affiliates Boston Gas and Colonial Gas Company subject to the Department's jurisdiction.

mechanism, it also should allow for a reasonable CIRM transition (Company Reply Brief at 9).

In response to the Attorney General's argument on rolling into base distribution rates the costs of post-test-year and rate year plant additions recovered through the CIRM, the Company asserts that the Attorney General's characterization of its proposal is flawed (Company Brief at 158). The Company maintains that its proposal is consistent with the Department's precedent on adjusting rate base to reflect the recovery of capital additions made through TIRFs and GSEPs from the end of the test year to the beginning of the rate year (Company Brief at 158, citing Boston Gas Company/Colonial Gas Company, D.P.U. 17-170, at 43, 48 (2018)). According to the Company, the Department accepted the proposal of the Company's affiliates to adjust rate base to reflect accumulated depreciation and ADIT as of the rate-year-end net plant balance on TIRF and GSEP investments to avoid double recovery of costs associated with these projects (Company Brief at 158-159, citing D.P.U. 17-170, at 40-41, 48). Accordingly, the Company maintains that it has made and will make appropriate adjustments to ensure that there is no double recovery between the CIRM and base distribution rates (Company Brief at 158-160, citing Exhs. NG-RRP-2 (Rev. 3), Sch. 1, at 3; NG-RRP-1, at 95-96; NG-PBRP-1, at 51). Therefore, the Company asserts that the Department should disregard the Attorney General's recommendation to roll forward all components of rate base if the Department allows the Company to include post-test-year and rate-year capital additions through the CIRM and PRB mechanisms (Company Brief at 160, citing Attorney General Brief at 16).

National Grid maintains that its alternative proposal, should the Department reject the proposed PBR, which is to continue the CIRM with an increased investment cap, is consistent with Department precedent (Company Brief at 54-55, citing D.P.U. 15-55, Exh. MLR-1). The Company affirms that its requested annual investment cap of $295 million is derived using actual, average annual capital expenditures from 2015 through 2017 per the Department's directives in the Company's last base distribution rate proceeding (Company Brief at 54-55, 457, citing D.P.U. 15-55, at 56 n.31). National Grid claims a continued need to recover incremental capital costs between base distribution rate cases, driven by factors including declining sales, changing regulatory requirements requiring increased or different investments, initiative to speed deployment of DER, investments to improve storm resilience or adapt to climate change, and aging and obsolete assets (Company Brief at 54-55, 456 citing Exh. NG-PCE-1, at 12-13, Tr. 8, at 1041).

D. Analysis and Findings

1. 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, cost related to system reliability, and capital expansion projects. D.P.U. 11-01/D.P.U. 11-02, at 73-74, 107; D.P.U. 10-70, at 47. 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 to adjust the 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. The Department noted that such ratemaking proposals could be similar in structure to the PBR mechanisms that electric and gas companies had in place during the decoupling proceeding. D.P.U. 07-50-A at 50.

In prior cases, when deciding whether to adopt 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. 13-90, at 36; D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 51-52; D.P.U. 09-39, at 80-84.[72] The Department has allowed capital cost recovery mechanisms in cases where a company adequately demonstrated its need to recover incremental costs associated with capital expenditure programs between base distribution rate proceedings. D.P.U. 10-55, at 121-122, 132-133; D.P.U. 09-39, at 79-80; D.P.U. 09-30, at 133-134. Conversely, without compelling evidence of lost growth in sales, the Department has declined to approve a capital

---

[72] National Grid was the first electric distribution company to receive approval for 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.

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 interest of ratepayers. D.P.U. 11-01/D.P.U. 11-02, at 111; D.P.U. 10-70, at 50, 52.

2. CIRM Transition

National Grid proposed, in the event that the Department approved its proposal to implement a PBR mechanism, it continue to collect through the CIRM the revenue requirement for capital additions placed into service between the end of the test year (i.e., December 31, 2017) and the end of the rate year (i.e., September 30, 2020) (Exh. NG-PBRP-1, at 49). In Section II.4., above, the Department approved the Company's proposal to implement a PBR mechanism, and, as such, we turn to whether, and to what extent, continuation of the CIRM is appropriate.

When establishing rates for the companies under its jurisdiction, the Department relies on historical test-year data adjusted for known and measurable changes. Eastern Edison Company, D.P.U. 1580, at 13-17, 19 (1984); Massachusetts Electric Company, D.P.U. 136, at 3 (1980); Chatham Water Company, D.P.U. 19992, at 2 (1980); Massachusetts Electric Company, D.P.U. 18204, at 4 (1975); New England Telephone and Telegraph Company, D.P.U. 18210, at 2-3 (1975); Boston Gas Company, D.P.U. 18264, at 2-4 (1975). The selection of a historical twelve-month period of operating data as the basis for setting rates is intended to provide a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will serve as a proxy for future operating results. Fitchburg Gas and Electric Light Company, D.T.E. 99-118, Interlocutory Order Regarding Scope of Proceeding and Motion to Compel Discovery at 8 (2001); Assabet Water Company, D.P.U. 95-92, at 28 (1996); D.P.U. 84-25, at 68-69; D.P.U. 1580, at 13-17; Ashfield Water Company, D.P.U. 1438/1595, at 3-4 (1984). Accordingly, the revenue requirement and resulting base distribution rates approved in this proceeding are designed to provide the Company sufficient funds to recover all of its prudently incurred distribution costs and the underlying expenses that are not recovered through reconciling charges between base distribution rate cases.

In establishing revenue decoupling, however, the Department stated that it would consider company-specific proposals to adjust the target revenues to account for capital spending and inflation, and we noted that such ratemaking proposals could be similar in structure to the PBR mechanisms that certain electric and gas companies had in place during the decoupling proceeding. D.P.U. 07-50-A at 50. Following the base distribution rates established through this proceeding, the Company will annually adjust base distribution rates in accordance with the PBR mechanism approved in this case. The PBR mechanism rate adjustments are designed to provide the Company sufficient funds to meet its service obligations while also providing the Company with incentives to be efficient in how it spends these funds. D.P.U. 17-05, at 379.

The currently effective CIRM factors went into effect on March 1, 2019, and are recovering nine months of the 2019 revenue requirement for July to December 2015 investments; nine months of the 2019 revenue requirement for 2016 investments; nine months of the 2019 revenue requirement for 2017 investments; and twelve months of the 2018 revenue requirement for 2017 investments. D.P.U. 18-46, at 3-4 & Exh. NG-2, at 1. The Company proposes to increase accumulated depreciation to capture the depreciation that will occur on those assets between the end of the test year, i.e., December 31, 2017, and the beginning of the period in which new base distribution rates are effective, i.e., October 1, 2019 (Exh. NG-RRP-1, at 95-96). Further, the Company proposes to adjust ADIT to roll forward deferred taxes related to pre-2018 investments recovered through the CIRM (Exh. NG-RRP-1, at 97). The Department allowed these adjustments in Section III.B.6., above. The Company has incurred and will continue to incur costs for investments made after the end of the test year, i.e., December 31, 2017, that are not included in the base distribution service revenue requirement approved in this case, were not collected through the CIRM, and would not be recovered through the PBR Mechanism. Accordingly, the Department determines it is appropriate to provide National Grid with some relief to transition from the CIRM to the PBR Mechanism. The Department finds it reasonable to allow National Grid to continue the CIRM by collecting the revenue requirement on capital additions placed into service in calendar year 2018 and calendar year 2019 through the CIRM factors with the current CIRM annual investment cap of $249 million (Exh. NG-PBRP-1, at 49). Further, the Department allows the Company to roll into base distribution rates all capital investments, including those above the CIRM investment cap, placed into service in calendar year 2018 and calendar year 2019 as part of the PBR Mechanism adjustments effective October 1, 2020, and October 1, 2021, respectively (Exh. NG-PBRP-1, at 49-50). The Department directs National Grid to cease recovery through the CIRM factors for the current year's revenue requirement as of October 1 each year and to continue the reconciliation component of the mechanism (Exhs. NG-PBRP-1, at 50; DPU-NG 19-1, Att. 1; DPU-NG 19-4; DPU-NG 19-5; DPU-NG 19-6). To avoid any double recovery, the Company shall adjust the PBR Mechanism revenue requirement, as recommended by the Attorney General, for the depreciation, return on rate base, associated federal and state income taxes, and property taxes for all existing assets ending December 31, 2018, for the October 1, 2020 PBR Mechanism adjustment and ending December 31, 2019, for the October 1, 2021 PBR Mechanism adjustment.

In addition, G.L. c. 164, § 94I, 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.[73] The

[73] An Act Relative to Competitively Priced Electricity in the Commonwealth, St. 2012, c. 209, § 20, inserted G.L. c. 164, § 94I:

> In each base distribution rate proceeding conducted by the [D]epartment under Section 94, the [D]epartment shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any [one] customer class would be more than [ten] percent, the [D]epartment shall phase in the elimination of any cross subsidies between rate classes on a revenue neutral basis phased in over a reasonable period as determined by the [D]epartment.

Department reaffirms its rate structure goals that are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 15-80/D.P.U. 15-81, at 298; Bay State Gas Company, D.P.U. 13-75, at 333 (2014); Bay State Gas Company, D.P.U. 12-25, at 447 (2012); D.P.U. 09-39, at 404. In this instance, the Department considers the PBR rate adjustments, which include the CIRM roll-ins, to be a change to base distribution rates where the ten-percent cap for any one customer class as a result of the change in revenue requirement is applicable. Accordingly, the Department directs the Company, in its first and second annual PRB Mechanism filings, to evaluate its proposal to determine whether the resulting impact for any one customer class is no more than ten percent, and if so, to propose a change that is in compliance with G.L. c. 164, § 94I.

We emphasize the importance of the Company providing systematic, ample, and contemporaneous documentation of all 2018 and 2019 plant additions in its CIRM filings that it seeks to roll into the PRB mechanism. A failure to provide clear, cohesive, and reviewable evidence demonstrating eligibility in a timely manner may result in disallowance of these costs in the PBR mechanism. Grid Modernization, D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 221 (2018); D.P.U. 95-40, at 7; D.P.U. 93-60, at 26-27; D.P.U. 92-210, at 24. The Department, therefore, expects the Company to provide a timely, organized, clear, and comprehensive filing of all supporting documentation of such 2018 and 2019 costs, which includes, but is not limited to (1) project descriptions, (2) project sanctioning papers, (3) construction work orders, (4) project closure reports, (5) variance analyses explaining the reasons for cost overruns and for demonstrating prudency, and (6) a summary of all proposed projects. Finally, the Department directs the Company in its compliance filing to adjust its PBR adjustment formula and modify its proposed PBR provision to incorporate the above directives (Exh. NG-HSG-13, Proposed M.D.P.U. No. 1400 (Bates Stamp 285)).

V. EXCESS ADIT

A. Introduction and Relevant Procedural History

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 ("2017 Tax Act") was signed into law.[74] Among other things, the 2017 Tax Act reduced the federal corporate income tax rate from 35 percent to 21 percent, effective January 1, 2018. Pub. L. No. 115-97, § 13001. On February 2, 2018, the Department, pursuant to G.L. c. 164, §§ 76, 93, 94 and G.L. c. 165, §§ 2, 4, opened an investigation into the effect on rates of the decrease in the federal corporate income tax rate on the Department's regulated utilities. Effect of Reduction in Federal Income Tax Rates on Rates Charged by Electric, Gas, and Water Companies, D.P.U. 18-15 (February 2, 2018).[75]

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, at 4. Thus, as part of the investigation, certain regulated utilities, including the Company, were directed to file a

---

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

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

proposal to refund to ratepayers the balance of excess ADIT as of December 31, 2017. D.P.U. 18-15, 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 property-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 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" to be included as a separate reconciling component in the Company's annual rate adjustment/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 rates established in the instant 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.[76] Finally, the

---

[76] 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

Department 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.

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.[77] D.P.U. 18-15-E, Compliance Filing at 2 & Att. 1 (Rev.) (January 15, 2019). 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 are proposed to take effect in the instant case. 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

---

Grid to itemize all ADIT amounts associated with specific reconciling mechanisms in its annual rate adjustment/reconciliation filing. D.P.U. 18-15-E at 36 n.32.

77 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.

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," 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 approved the Company's credit of excess ADIT for the period of January 1, 2019 through September 30, 2019. Massachusetts Electric Company/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.

B. Company Proposal

In its initial filing, National Grid proposed an annual amortization of total excess ADIT of $6,797,006 to be included in base distribution rates, based on an excess ADIT balance that included $247,688,552 in protected and unprotected excess ADIT (Exhs. NG-RRP-2, Sch. 10 at 3; NG-RRP-5, at 8). During the course of the proceedings, National Grid made several adjustments to its excess ADIT totals and proposed different amortization periods for several classifications of its excess ADIT (Exhs. NG-RRP-2

(Revs. 1-3), Sch. 10, at 3 & Sch. 11, at 1; DPU-NG 10-2 & Supps. 1, 2; DPU-NG 21-16; RR-AG-20, Att. at 1). Based on the revised calculations of excess ADIT and proposed amortization periods, National Grid now proposes an annual amortization of total excess ADIT of $4,457,239, based on a total excess ADIT balance at September 30, 2019, of $259,796,675 (Exhs. NG-RRP-2 (Rev. 4), Sch. 10, at 3; NG-RRP-5 (Rev. 4), at 9; RR-AG-20, Att. at 1).

The Company's total excess ADIT balance at September 30, 2019 of $259,796,675 is comprised of the following: (1) $218,740,467 in protected property-related excess ADIT; (2) a $42,930,674 net operating loss ("NOL")[78] balance, which the Company proposes to apply as an offset to the protected property-related excess ADIT; (3) $67,843,677 in unprotected property-related excess ADIT; (4) $15,122,667 in unprotected non-property-related excess ADIT; and (5) $1,020,538 in unprotected excess ADIT associated with NGSC (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3; RR-AG-20, Att. at 1-2).[79] This total excess ADIT balance includes amounts associated with the CIRM, Pension/PBOP, solar, and smart grid pilot reconciling mechanisms (Exh. DPU-NG 10-2 (Supp. 2); RR-AG-20, Att. at 1).

---

[78] A business may have an NOL for tax purposes if its tax deductions for the year are more than its business income. Internal Revenue Service ("IRS") Publication 5318 for tax year 2018.

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

With respect to amortization periods, the Company now proposes to amortize its protected property-related excess ADIT balance over an average service life of 39 years rather than 50 years, for an annual amortization amount of $5,613,805 (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3). Further, the Company proposes to amortize its NOL balance over approximately eight years, which produces an annual offset of $5,385,101 to be applied against the protected property-related excess ADIT annual amortization amount (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3). National Grid proposes to amortize all of its unprotected excess ADIT over the average remaining service lives of the underlying assets, which it calculates as 20.1 years, rather than over different periods for MECo and Nantucket Electric (Exhs. NG-RRP-1, at 101-102; NG-RRP-2 (Rev. 4), Sch. 10, at 3). This results in an annual amortization of $3,367,562 for the Company's unprotected property-related excess ADIT balance and an annual amortization of $750,645 for the Company's unprotected non-property-related excess ADIT balance (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3). Finally, the Company proposes to amortize the excess ADIT associated with NGSC over approximately 9.3 years, for an annual amortization amount of $110,328 (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3).

Based on the above revised calculations of excess ADIT and proposed amortization periods, National Grid's proposes an annual excess ADIT amortization of $4,457,239 (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3). In addition to this proposed excess ADIT pass back, National Grid proposes an adjustment to rate base of $4,478,297 to account for the excess ADIT amortization that will take place during the Company's rate year ending September 30, 2020 (Exhs. NG-RRP-2, at 97; NG-RRP-2 (Rev. 4) Sch. 11, at 1, 4).[80]

C. Position of the Parties

1. Attorney General

The Attorney General raises several issues with the Company's proposed excess ADIT-related adjustments. First, the Attorney General argues that the $15,122,667 in unprotected non-property-related excess ADIT should be amortized over five years (Attorney General Brief at 26; Attorney General Brief at 13). She reasons that there is no particular logic for amortizing the unprotected non-property related excess ADIT over the average remaining life of the assets, as non-property related excess ADIT is, by definition, not related to plant (Attorney General Brief at 29). Further, the Attorney General notes that the turn-around for non-property related excess ADIT is generally less than the amortization period proposed by the Company (Attorney General Brief at 29). In addition, the Attorney General disagrees with the Company's claim that it is administratively easier to use the same amortization period for all unprotected excess ADIT, as she notes that the use of a different

---

80 The Company proposed a deduction to rate base for adjusted test-year excess ADIT balance of $249,846,956, which is comprised of the following: (1) $132,353,804 in protected excess ADIT associated with base distribution rates; (2) $40,646,650 in protected excess ADIT associated with the CIRM; (3) $2,210,667 in protected excess ADIT associated with solar; (4) $625,533 in protected excess ADIT associated with smart grid pilot; (5) $59,607,560 in unprotected excess ADIT associated with base distribution rates; and (6) $14,402,740 in unprotected excess ADIT associated with the CIRM (Exh. DPU-NG 10-2 (Supp. 2)). The Company proposed what it considered to be a known and measurable adjustment of $4,478,297 to account for the annual amortization of excess ADIT, which results in a total deduction to rate base for excess ADIT of $245,368,659 (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 1, 4).

amortization period would be "nothing more than a simple accounting mechanism" (Attorney General Brief at 28). The Attorney General also argues that the Company's reliance on the Department's findings in D.P.U. 17-170 to support its proposal is misplaced, as the proper amortization period for unprotected non-property-related excess ADIT was not specifically at issue in that case (Attorney General Brief at 28-29). Rather, the Attorney General points to the Department's decision in D.P.U. 15-155, and she argues that the Company's proposal is inconsistent with the Department's finding in that case that a five-year amortization period was appropriate for the non-plant related ADIT (Attorney General Brief at 29, citing D.P.U. 15-155, at 257-258; Attorney General Reply Brief at 13). The Attorney General asserts that the effect of amortizing the $15,122,667 in unprotected non-property-related excess ADIT over five years is to increase the annual amortization of excess ADIT by $2,273,888 and to decrease the Company's revenue requirement by $3,171,445 (Attorney General Brief at 29-30, citing Exh. AG-DJE, Schs. DJE-1 (Rev. 2), DJE-4 (Rev. 2)).

Second, the Attorney General challenges the Company's proposal to accelerate the amortization period of the NOL balance associated with protected property-related excess ADIT (Attorney General Brief at 30-34). The Attorney General notes that the Company's proposed annual amortization of its protected property-related excess ADIT is $5,613,805, and its proposed annual amortization of the associated NOLs is an offset of $5,385,101 (Attorney General Brief at 33, citing Exh. NG-RRP-2 (Rev. 2), Sch. 10, at 3). She claims that the difference of $228,704 represents the amortization of excess ADIT associated with the Company's solar program and smart grid pilot, neither of which has associated NOL balances (Attorney General Brief at 33, citing Exh. NG-RRP-2 (Rev. 2), Sch. 10, at 3). Thus, according to the Attorney General, the Company's proposed amortization of its NOL balance essentially "zeroes out" the amortization amounts attributable to the protected property-related excess ADIT and leaves only a "relatively minor" amortization of excess ADIT related to the solar program and the smart grid pilot available to be refunded to ratepayers (Attorney General Brief at 32-33, citing Exh. DPU-NG 10-2). The Attorney General argues that the Company provided insufficient justification for this change and should not be allowed to deny current ratepayers the benefit of the return of the protected property-related excess ADIT by disproportionately amortizing the related NOLs over a different period of time (Attorney General Brief at 33-34; Attorney General Reply Brief at 13-14). The Attorney General asserts that the Company should be required to amortize the NOLs over the same 39-year period as the plant-related protected excess ADIT (Attorney General Brief at 34; Attorney General Reply Brief at 14). According to the Attorney General, a consistent method of amortizing the NOLs and plant-related protected excess ADIT would result in an annual NOL amortization of $1,101,783, or an increase of $4,283,318 to the current proposed annual amortization amount (Attorney General Brief at 34, citing Exh. NG-RRP-2 (Rev. 3), Sch. 10, at 3; AG-DJE-Surrebuttal-1, Sch. DJE-R-4 (Rev. 2)). She asserts that this correction to the Company's amortization of its NOL balance reduces the Company's revenue requirement by $5,974,043[81] (Attorney General Brief at 34-35, citing Exh. AG-DJE-Surrebuttal-1, Sch. DJE-R-1 (Rev. 2)).

81 This proposed adjustment consists of $4,283,318, plus associated income taxes and

Third, the Attorney General argues that the Department should reject the Company's proposed adjustment to rate base to record the excess ADIT amortization that will take place during the rate year (Attorney General Brief at 24). According to the Attorney General, such a "selective adjustment" is inappropriate because it takes into account changes only to one component of the Company's rate base after the test year (Attorney General Brief at 24-25; Attorney General Reply Brief at 5).[82] Alternatively, the Attorney General contends that, if the Department allows the Company's proposed rate base adjustment, reasoned consistency requires the Company to make corresponding adjustments for other expense accruals that reduce rate base (Attorney General Brief at 24, citing Boston Gas Company v. Department of Public Utilities, 367 Mass. 92, 104 (1975); Boston Gas Company v. Department of Public Utilities, 368 Mass. 780, 802 (1975); Attorney General Reply Brief at 5-6). In particular, the Attorney General asserts that the Department should require the Company to deduct from rate base the post-test year depreciation expense accrual associated with the balance of accumulated depreciation, which she calculates as $143,361,821 (Attorney General Brief at 25).

---

bad debt (Exh. AG-DJE-Surrebuttal-1, Sch. DJE-R-1 (Rev. 2)).

82 The Attorney General distinguishes this proposed adjustment from the Company's proposal to roll forward deferred taxes related to pre-2018 investments recovered through the CIRM, smart grid, and solar phase II mechanisms (Attorney General Brief at 24-25, citing Exh. AG-DJE-18; AG 3-7). According to the Attorney General, the roll forward related to CIRM, smart grid, and solar phase II mechanisms are "derivative adjustment" associated with adjustments to plant and accumulated depreciation and are intended to synchronize the test-year rate base with the recovery of CIRM, smart grid, and solar phase II investments (Attorney General Brief at 25, citing Exh. AG-DJE-18).

2. Company

On brief, National Grid summarized the aforementioned excess ADIT amounts and proposed amortization periods (Company Brief at 170-172). The Company also responded to the Attorney General's arguments discussed above. First, National Grid asserts that it "takes no position" on the Attorney General's argument that the $15,122,667 in unprotected non-property-related excess ADIT should be amortized over five years, rather than 20.1 years as the Company proposed (Company Brief at 173). National Grid, however, notes that, in the event of a future income tax increase, the Company would need to recover the amounts amortized over the course of the Attorney General's proposed five years (Company Brief at 173).

Second, National Grid disputes the Attorney General's claim that the Company changed the amortization method applicable to the NOL balance (Company Brief at 173-174; Company Reply Brief at 88). National Grid argues that, at the time of its initial filing, it was unable to separate protected from unprotected property-related excess ADIT balances or to provide definitive amounts of property-related excess ADIT (Company Brief at 174; Company Reply Brief at 88). Thus, the Company asserts that it provided a high-level estimate of a "reasonable amortization amount that did not violate the 2017 [Tax Act] normalization rules" (Company Brief at 174, citing Exh. NG-RRP-1, at 101; Company Reply Brief at 88). Further, the Company claims that it did not choose a specific amortization method, as there were "too many unknown variables while the base rate proceeding was still pending" (Company Brief at 174; Company Reply Brief at 88). National Grid asserts that, upon its filing of its 2018 income tax return and with the implementation of the deferred tax module in PowerTax,[83] the Company was finally able to provide a final balance for the protected and unprotected property-related excess ADIT (Company Brief at 174, citing Exh. NG-RRP-1, at 100-101; Company Reply Brief at 88).

Third, National Grid asserts that its proposal to adjust rate base to account for the annual amortization of excess ADIT is appropriate because the increase is a unique, one-time adjustment necessitated by the 2017 Tax Act, and not subject to ebb and flow (Company Brief at 172; Company Reply Brief at 83). Thus, while National Grid concedes that other items included in rate base experience positive and negative changes throughout the year, the Company claims that the excess ADIT balance will only decrease over time by a known and measurable amount, and there will be no other changes or offsets to this balance throughout the year (Company Brief at 172-173; Company Reply Brief at 83). The Company argues that it would be inappropriate to adjust other rate base items, such as accumulated depreciation, to offset the proposed excess ADIT adjustment, because the rate year activities in those accounts are not known and measurable (Company Brief at 173).

[83] PowerTax is tax preparation software that allows the Company to match up the historical book depreciation amounts by vintage year of investment and by asset type preparation (Exh. NG-RRP-1, at 101). This module also is used to accurately determine the timing of reversal of the underlying plant related book/tax timing differences, which enables the Company to determine the timing for the passback to customers (Exh. NG-RRP-1, at 101).

D. Analysis and Findings

1. Introduction

Deferred income taxes are accrued when a company has a current deduction or credit for tax purposes, but not for book purposes. The Berkshire Gas Company, D.P.U. 90-121, at 136 (1990). The ADIT balance is a source of interest-free funds provided by ratepayers[84] that a company can use without incurring borrowing costs or invest and accrue interest until the balance is needed to fund the taxes due and payable in later years. Therefore, for ratemaking purposes, ADIT represents an offset to a company's rate base. D.P.U. 87-59, at 63; AT&T Communications of New England, Inc., 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).

As a result of the reduction in the federal corporate tax rate, the Company will restate all of its net ADIT liability balances based on the new 21-percent federal income tax rate (Exh. NG-RRP-1, at 99). Thus, excess ADIT represents the portion of ADIT that is no longer owed to the government by virtue of the lower tax rates effective January 1, 2018, and is subject to refund to ratepayers consistent with Internal Revenue Service ("IRS") normalization rules to avoid creating a normalization violation (Exh. NG-RRP-1, at 101).[85]

---

84 Income tax expense is a part of a company's cost of service recovered through rates charged to customers. See, e.g., Galveston Electric Company v. City of Galveston, 258 U.S. 388, 399 (1922).

85 In general, normalization is a system of accounting used by regulated public utilities to reconcile the tax treatment of accelerated depreciation of public utility assets with their regulatory treatment. Safe Harbor for Inadvertent Normalization Violations,

2. Excess ADIT Balances and Amortization Periods

National Grid has provided what it considers its final total excess ADIT balance of $259,796,675 at September 30, 2019, and it proposes to return an annual amortization amount to ratepayers of $4,457,239 based on various proposed amortization periods (Exhs. NG-RRP-2 (Rev. 4), Sch. 10, at 3; DPU-NG 10-2 (Supp. 2); Tr. 7, 1007-1008; RR-AG-20, Att. at 1-2). The Attorney General did not challenge the Company's calculation of its total excess ADIT balance of $259,796,675 or the components of the total balance. The Department has reviewed the Company's excess ADIT amounts and supporting documentation, and we find them to be acceptable at this time (Exhs. NG-RRP-2 (Rev. 4), Sch. 10, at 3; DPU-NG 10-2 (Supp. 2); DPU-NG 10-3; RR-AG-20, Att.). As such, the Department approves the Company's total excess ADIT balance of $259,796,675 for the purposes of calculating the annual amortization amount to ratepayers.

The Department recognized that the amortization periods approved in D.P.U. 18-15-E were subject to change once National Grid's audited financial statements for its fiscal year ending 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 Attorney General does not challenge the Company's proposal to amortize (1) protected property-related excess ADIT over an average service life

---

Revenue Procedure 2017-47, at 1 (September 7, 2017); Boston Edison Company, D.P.U. 10774 (1953). Under normalization, a utility receives the tax benefit of accelerated depreciation in the early years of an asset's regulatory useful life and passes that benefit through to ratepayers ratably over the regulatory useful life of the asset in the form of reduced rates. Revenue Procedure 2017-47, at 1-2.

of 39 years, (2) unprotected property-related excess ADIT over an average service life of 20.1 years, or (3) unprotected NGSC-related excess ADIT over approximately 9.3 years (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3). The Attorney General, however, challenges the Company's proposed amortization periods applicable to its unprotected non-property-related excess ADIT and its NOL balance (Attorney General Brief at 26, 34; Attorney General Brief at 13-14).

While the IRS has prescribed the method by which a company passes back excess ADIT related to protected items,[86] the Department has greater discretion in determining the appropriate amortization period for excess ADIT related to unprotected items for ratemaking purposes. See, e.g., D.P.U. 15-155, at 257; NSTAR Gas Company, D.P.U. 14-150, at 241-242 (2015); D.P.U. 90-121, at 136-140; D.P.U. 92-210, at 86-89. In determining an appropriate amortization period, the Department must balance the interests of the company and its ratepayers, taking into consideration such factors as the amount under consideration for amortization, the value of such an amount to ratepayers based on certain amortization periods, and the effect of the adjustment on the utility's finances and income. Fitchburg Gas and Electric Light Company, D.P.U. 09-09, at 57 (2009); Fitchburg Gas and Electric Light Company, D.T.E. 99-66-A at 28-29 (2001). Amortizations are based on a case-by-case review of the evidence and underlying facts. Aquarion Water Company of Massachusetts,

86 Under IRS normalization rules, reserves for excess ADIT associated with protected property are reduced over the life of the associated property. Pub. L. No. 115-97, § 1561(d) (1), (2). A violation of these normalization rules could have adverse tax consequences for the public utility, including potential tax penalties under the 2017 Tax Act. See Pub. L. No. 115-97, § 1561(d) (3), (4).

D.P.U. 08-27, at 99 (2009); see also Barnstable Water Company, D.P.U. 93-223-B at 14 (1994); D.P.U. 84-145-A at 54.

Based on our review of the record, the Department approves the Company's proposal to amortize its protected property-related excess ADIT over an average service life of 39 years, subject to our additional findings below (Exhs. NG-RRP-2 (Rev. 4), Sch. 10, at 3; DPU-NG 10-2 & (Supp. 2)). Further, we find that Company's proposal to amortize its unprotected property-related excess ADIT over an average service life of 20.1 years and its unprotected NGSC-related excess ADIT over approximately 9.3 years, strikes a reasonable balance between the interests of the Company and its ratepayers, taking into account such factors as the amount under consideration for amortization, the value of such an amount to ratepayers based on certain amortization periods, and the effect of the adjustment on the utility's finances and income. D.P.U. 09-09, at 57; D.T.E. 99-66-A at 28-29. As such, these amortization periods are approved, subject to our additional findings below.

With respect to the Company's unprotected non-property-related excess ADIT, the Attorney General argues that the $15,122,667 balance should be amortized over five years rather than the 20.1 years proposed by the Company (Attorney General Brief at 26; Attorney General Brief at 13). National Grid takes no position on this issue, but asserts that, in the event of a future income tax increase, the Company would need to recover the amounts amortized over the course of the Attorney General's proposed five years (Company Brief at 173). The Department finds that a shorter turnaround period associated with the Company's portion of unprotected non-property-related excess ADIT is both reasonable and consistent with Department precedent. D.P.U. 15-155, at 257-258; D.P.U. 14-150, at 241-242; Oxford Water Company, D.P.U. 88-171, at 34-36 (1989); Hingham Water Company, D.P.U. 88-170 (1989). Cf. D.P.U. 18-15-D at 10, 18-19 (20-year amortization accepted because of tentative nature of excess ADIT balances). In this regard, we find that a five-year amortization period strikes a reasonable balance between the interests of the Company and its ratepayers, taking into consideration the aforementioned factors. D.P.U. 09-09, at 57; D.T.E. 99-66-A at 28-29. As such, we approve a five-year amortization period applicable to the Company's unprotected non-property-related excess ADIT. Using a five-year amortization period for the Company's unprotected non-property-related portion of excess ADIT results in an annual amortization of $3,024,533 (i.e., $15,122,667/5 years) as opposed to the Company's proposed annual amortization of $750,645 (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3).

Regarding the NOL balance, the Attorney General argues that the Company should not be allowed to accelerate the amortization period, and instead it should be required to amortize the NOL balance over the same 39-year period applicable to the protected plant-related excess ADIT (Attorney General Brief at 34; Attorney General Reply Brief at 14). National Grid argues that it did not change the amortization method applicable to the NOL balance because the Company never selected a specific amortization method prior to filing its 2018 income tax return and the implementation of the deferred tax module in PowerTax (Company Brief at 174, citing Exh. NG-RRP-1, at 100-101; Company Reply Brief at 88).

The Company's proposal allows it to utilize the NOL balance to the fullest extent possible to offset the taxable income generated by the amortization of the protected plant-related excess ADIT balances, until the NOL balance is fully utilized (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3). There is nothing on the record to suggest that the Company's proposal violates any current IRS normalization regulations. Further, we find that the Attorney General's argument to amortize the NOL balance over 39 years is unpersuasive, as it would extend the amortization period over many decades into the future, long after any existing NOL can be used as an offset. Thus, it is the Attorney General's proposed amortization period that would create an intergenerational inequity where present customers would be required to share benefits with future customers, although the underlying activity provided no benefit to these future customers. See D.P.U. 11-01/D.P.U. 11-02, at 249. Based on these considerations, the Department approves National Grid's proposed amortization period applicable to its NOL balance, subject to our additional findings below.

3. Ratemaking Treatment of Excess ADIT

The Company proposes an annual amortization amount of $4,457,239, to be included in base distribution rates (Exhs. NG-RRP-2 (Rev. 4), Sch. 10, at 3; NG-RRP-5 (Rev. 4), at 9; RR-AG-20, Att. at 1). Further, the Company's total excess ADIT balance, from which the annual amortization amount is derived, includes excess ADIT associated with NGSC and the CIRM, Pension/PBOP, solar program, and smart grid pilot reconciling mechanisms (Exhs. NG-RRP-2 (Rev. 4), Sch. 10, at 3; DPU-NG 10-2 (Supp. 2)).

As noted above, in D.P.U. 18-15-E, the Department determined that the Company's approved Tax Credit Provision would remain in effect until the total excess ADIT balance is transferred to the new base distribution rates established in the instant proceeding, unless the Department ordered otherwise. D.P.U. 18-15-E at 36 n.31. Further, the Department determined that it would investigate in the instant case 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).

On May 7, 2019, the IRS issued a Request for Comments on Necessary Clarifications to Normalization Requirements for Excess Tax Reserves Resulting from the Corporate Tax Rate Decrease, Notice 2019-33 ("Notice 2019-33"). According to Notice 2019-33, the Department of the Treasury and the IRS, following an opportunity to comment, intend to issue guidance under Section 168 of the Internal Revenue Code (26 U.S.C. § 168) to clarify the normalization requirements for excess tax reserves resulting from the decrease in the federal corporate income tax. Notice 2019-33, at 1, 8-10. On the surface, it appears that some of the issues upon which the Department of the Treasury and IRS seek comment could affect the excess ADIT balances and amortization method used by the Company to derive the amortization periods approved in this Order. Notice 2019-33, at 8-10.[87] As of the date of

[87] For instance, the Department of Treasury and IRS seek comment on alternative methods for accounting for excess ADIT; whether depreciation-related NOLs as of December 31, 2017, must be analyzed for normalization purposes; and the method of

this Order, the Department is unaware of any official decision from the Department of Treasury and the IRS.[88]

Given the potential changes to National Grid's amortization method, and, consequently, the annual amortization amount, based on the anticipated clarification of normalization requirements by the Department of Treasury and IRS, the Department finds that it is more appropriate for the Company to retain the Tax Credit Provision. As such, the Company shall continue to return to ratepayers excess ADIT through the Tax Credit Provision. In addition, consistent with the Department's findings in Section VII.C., below, the Company is directed to return to ratepayers the excess ADIT associated with the smart grid pilot through the smart grid adjustment provision (Exh. DPU-NG 10-2 (Supp. 2)).

4. Rate Base Adjustment

In addition to the foregoing issues, the Attorney General also challenges the Company's proposed rate base adjustment to account for the annual amortization of excess ADIT. The Attorney General argues that the Company's proposal is inappropriate because it takes into account changes to only one component of the Company's rate base after the test year (Attorney General Brief at 24-25; Attorney General Reply Brief at 5). National Grid

---

reversing protected (by the normalization rules) versus unprotected ADIT as a result of the 2017 Tax Act. Notice 2019-33, at 8-10.

88 The deadline for submitting comments was July 29, 2019. Notice 2019-33, at 10. The Department notes that on August 12, 2019, the IRS issued Bulletin 2019-33, which, in part addressed certain accounting procedures under the 2017 Tax Act. The bulletin, however, does not appear to implicate any of the 2017 Tax Act-related matters discussed in Notice 2019-33.

counters that the proposal is appropriate because it represents a unique, one-time adjustment necessitated by the 2017 Tax Act, and it is not subject to ebb and flow (Company Brief at 172; Company Reply Brief at 83). As a result of the Department's decision directing National Grid to retain the Tax Credit Provision, the Company's rate base adjustment proposal is effectively moot. Nevertheless, even if the Department had determined that the Company could adjust rate base by the annual amortization amount of excess ADIT, we are not persuaded that such an adjustment would be appropriate.

A test year is intended to provide a representative level of a company's revenues and expenses which, when adjusted for known and measurable changes, will 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; D.P.U. 95-92, at 28; D.P.U. 84-25, at 68-69; D.P.U. 1580, at 13-17; D.P.U. 1438/1595, at 3-4.

We find that National Grid's excess ADIT balances are no more unique than the balances of its other rate base components. To update one element of a company's cost of service independently, such as the ADIT component of rate base, would disrupt the balance achieved between costs and revenue requirement by using an historical test year. D.P.U. 13-75, at 107; see also D.P.U. 1350, at 18-19. While the underlying 2017 Tax Act is a known and measurable event (D.P.U. 18-15-A at 29, 49), the effects of the 2017 Tax Act on the Company's rate base are no different than the plethora of other potential post-test year adjustments, such as plant additions and retirements, depreciation accruals, inventory balances, and changes to other rate base offsets such as customer deposits and advances.

Boston Gas Company, D.T.E. 98-67 (Phase I) at 27-28 (1988); Massachusetts-American Water Company, D.P.U. 1700, at 3-6 (1984). Moreover, as noted above, the Company's calculated excess ADIT has been modified several times over the course of these proceedings (Exhs. NG-RRP-2 (Revs. 1-3), Sch. 10, at 3; NG-RRP-2, Sch. 11, at 1 (Revs. 1-3); DPU-NG 10-2 & (Supps. 1, 2); RR-AG-20, Att. at 1). These revisions, in conjunction with potential of further clarifications to normalizing requirements for excess tax reserves resulting from the 2017 Tax Act contemplated by Notice 2019-33, would render the Company's proposed adjustment as insufficiently established so as to warrant the unusual treatment of a post-test year rate base adjustment. Cf. D.P.U. 13-75, at 130-132 (company outsourcing of inventory requirements warranted elimination of test year-end materials and supplies balance from rate base).

Based on all the foregoing considerations, the Department finds that even if we were to determine that National Grid could adjust rate base for the annual amortization of excess ADIT, the Company has not provided sufficient justification to warrant the adoption of its proposal. Accordingly, the Company's proposed rate base is reduced by its proposed annual amortization amount of $4,478,297.

5. Conclusion

As a result of the Department's decisions above, the Company's unprotected non-property-related excess ADIT shall be amortized over five years, which produces an annual amortization of $3,024,533 (Exh. NG-RRP-2 (Rev. 4), Sch. 10, at 3). In addition, because the Company's total excess ADIT balance includes excess ADIT associated with the

Company's reconciling mechanisms, the Company shall remove from the total excess ADIT the amount of $625,533 in excess ADIT associated with the smart grid pilot (Exh. DPU-NG 10-2 (Supp. 2)). National Grid is directed to submit in its compliance filing a revised Exhibit NG-RRP-2 (Rev. 4), Schedule 10 showing these changes and the calculation of the new annual amortization amount.

Further, the Company shall include in its compliance filing a Tax Credit Provision designed to return to ratepayers a total excess ADIT amount of $259,171,142 ($259,796,675 less $625,533 associated with the smart grid pilot), plus tax gross up, over the amortization periods approved herein and consistent with the other findings herein. National Grid shall allocate the excess ADIT to be returned to ratepayers among rate classes using the distribution revenue allocators approved in this proceeding, and the Company shall refund the amounts to customers through a volumetric rate credit.

Finally, as noted above, the Company's proposed rate base is reduced by $4,478,297 associated with the annual amortization amount. The Company shall adjust its income taxes to account for the recovery of the annual amortization amount through the Company's Tax Credit Provision. The effect of the rate base reduction on the Company's revenue requirement is provided in the Schedules appended to this Order.

VI. SOLAR PHASE II ROLL-IN

A. Introduction

National Grid proposes to include 18 facilities associated with its solar phase II program in its base distribution rates and close out the solar phase II reconciling mechanism

(Exhs. NG-RRP-1, at 8, 10; WP NG-RRP-2, at 3-4; WP NG-RRP-3b, at 1). National Grid included in its proposed cost of service these expenses associated with the solar phase II facilities: (1) $758,069 in O&M expense; (2) $773,381 in income taxes; (3) $574,894 in property taxes; and (4) $2,829,385 in depreciation expense (Exh. AG 16-5, Att.). The Company proposes to include $36,653,148 in rate base comprised of: (1) $49,657,919 in plant in service; (2) a credit of $6,530,950 related to accumulated depreciation; and (3) a credit of $6,473,821 related to ADIT (Exh. AG 16-5, Att.). These costs are offset by $1,812,454 from the revenue produced from these facilities during the test year from sales of energy through the ISO-NE market and the market value of the solar renewable energy certificates generated by the solar phase II facilities (Exh. WP NG-RRP-3b (Rev. 4), at 1, 3). The Company calculated the revenue requirement associated with the solar phase II facilities as of September 30, 2019, to coincide with the October 1, 2019, effective date of new base distribution rates (Exhs. NG-RRP-1, at 8; WP NG-RRP-2, at 3-4).

The Company states that six of the 18 solar phase II facilities that it proposes to include in rate base were put into service after the end of the test year (Exhs. NG-RRP-1, at 10; WP NG-RRP-2, at 3-4). The Company acknowledges that the revenue included in its base distribution rate revenue requirement calculation does not include any revenues generated from the six post-test-year facilities or received in the ISO-NE forward capacity market (Exh. DPU-NG 1-1). Accordingly, the Company proposes to continue to include any revenue in excess of the $1,812,454 included in base distribution rates from its solar phase II facilities in its solar phase III annual reconciliation for recovery until the Company's next distribution rate case (Exh. DPU-NG 1-1).

B. Position of the Parties

On brief, the Company reiterates its proposal to roll into rate base the cumulative capital investment made in relation to the solar phase II program through December 31, 2018 (Company Brief at 157, 249). The Company notes that its proposal includes an adjustment to test-year utility plant in service of six solar phase II sites that went into service in 2018 (Company Brief at 157 n.50, 249-250). No other party commented on this issue on brief.

C. Analysis and findings

The Department allows the Company to roll-in to its base distribution rates the costs related to the twelve solar phase II facilities completed prior to the end of the test year.[89] The Department does not recognize post-test-year additions or retirements to rate base, unless the utility demonstrates that the addition or retirement represents a significant investment that has a substantial effect on its rate base. D.P.U. 96-50-C at 16-18, 20-21; D.P.U. 96-50 (Phase I) at 15-16; D.P.U. 95-118, at 56, 86; D.P.U. 85-270, at 141 n.21; D.P.U. 1700, at 5-6. As a threshold requirement, a post-test-year addition to plant must be known and measurable, as well as in service. Dedham Water Company, D.P.U. 84-32, at 17 (1984); D.P.U. 906, at 7-11. The Department has historically judged the significance of an

[89] The Department has previously ruled on these investments' prudency in solar cost adjustment provision proceedings. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 16-33-A (2017); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 16-153-A (2017); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 17-42-A (2018).

investment by comparing the size of the addition in relation to rate base and not based on the particular nature of the addition. Western Massachusetts Electric Company, D.P.U. 1300, at 14-15 (1983).

The Company has filed for cost recovery of the six post-test-year facilities in two separate dockets in accordance with its solar cost adjustment provision tariff (M.D.P.U. No. 1406). Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 18-23 (filed March 1, 2018); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 18-93 (filed August 31, 2018). In those dockets, the Department is reviewing and has not ruled on the underlying capital costs and whether the Company acted prudently in constructing the facilities. Therefore, the Department finds that the Company's proposal fails to satisfy the threshold requirement of being known and measurable as well as in service.[90]

Even if the Company had supported its proposal to include post-test-year costs in rate base in this proceeding, National Grid has failed to demonstrate that the facilities represent significant investments that have a substantial effect on its rate base. When considering the significance of post-test-year addition, the Department has previously found it appropriate to evaluate individual post-test-year projects rather than to evaluate projects in aggregate.

---

90 There is a discrepancy between the in-service dates for the two projects submitted in D.P.U. 18-23 and in this proceeding. In D.P.U. 18-23, the Company states that the two facilities were in service on December 30, 2017. D.P.U. 18-23, Exh. WFJ-1, at 3. In this proceeding, the Company states that these same two facilities were in service after December 31, 2017 (Exhs. NG-RRP-1, at 10; WP NG-RRP-3 (Rev. 4), at 3). We rely on the record in this proceeding in making our decision.

D.P.U. 17-05, at 102; D.P.U. 13-75, at 108-109; Oxford Water Company, D.P.U. 1699, at 4 (1984); D.P.U. 1700, at 5-6.

Investment costs for National Grid's six post-test-year solar phase II facilities proposed for inclusion are \$3,773,074, \$3,699,006, \$3,669,379, \$2,910,056, \$3,061,207, and \$2,438,710 (see Exh. WP NG-RRP-2 (Rev. 4), at 3, col. (d) & col. (g)). The Company's adjusted test-year rate base was \$2,229,882,003 (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 1). The Department finds that, when compared to the adjusted test-year rate base of \$2,229,882,003, none of these facilities represent significant additions (Exhs. NG-RRP-2 (Rev. 4), Sch. 11, at 1; WP NG-RRP-2 (Rev. 4), at 3).[91] Because the Department finds that the post-test-year solar phase II facilities do not meet the Department's significance requirement, we disallow their inclusion in base distribution rates. See, e.g., D.P.U. 17-05, at 103-104; D.P.U. 13-75, at 105-109; Milford Water Company, D.P.U. 12-86, at 77-78 (2013).

Based on the foregoing, the Department denies the Company's proposal to include post-test year solar phase II investments in its base distribution rate revenue requirement and, accordingly, we decrease its plant by \$19,551,432, decrease its accumulated depreciation by \$1,233,204, decrease its ADIT by \$2,097,928, and decrease its depreciation expense by \$1,143,094 (Exhs. NG-RRP-2 (Rev. 4), Sch. 6, at 1; WP NG-RRP-2 (Rev. 4), at 3, line 21,

---

91 Even if the Department considered the six solar phase II facilities in aggregate, they would constitute only 0.80 percent of the Company's test-year-end rate base (Exhs. NG-RRP-2 (Rev. 4), Sch. 11, at 1; WP NG-RRP-2 (Rev. 4), at 3).

col. (d) & col. (g); WP NG-RRP-2 (Rev. 4), at 4; AG 16-5, Att.).[92] In addition, the Department directs the Company to modify its solar cost adjustment provision tariff to retain the six post-test-year solar phase II facilities.[93]

VII. SMART GRID PILOT PROGRAM ROLL-IN

A. Introduction

In 2012, the Department approved National Grid's smart grid pilot program. Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 11-129 (2012). This program was established as part of An Act Relative to Green Communities, St. 2008, c. 169 to explore the effectiveness of smart meters, automated load management systems embedded with current demand-side management programs, remote status detection and operation of distribution equipment, and time-of-use pricing to reduce peak and average load of those participating in the program. D.P.U. 11-129, at 2. In D.P.U. 11-129, at 101-102, the Department approved National Grid's proposal to recover customer-facing smart grid pilot program costs from the Company's basic service customers through smart grid customer cost

---

92 For the six post-test-year solar phase II facilities, the Company included utility plant costs of $14,989,250 for panels, $3,747,733 for inverters, and $814,449 for battery storage (see Exh. WP NG-RRP-2 (Rev. 4), at 3, line 21, col. a & col. e (panels), col. b & col. f (invertors), col. c (storage)). The Department calculated depreciation expense on these plant costs using depreciation rates of five percent on panels, 8.33 percent on inverters, and ten percent on battery storage to calculate these depreciation adjustments (Exh. NG-RRP-2 (Rev. 4), Sch. 6, at 1).

93 We also note that the Company has recognized that any revenue in excess of the $1,812,454 included in base distribution rates from its solar phase II facilities will be included in its solar phase III annual reconciliation for recovery until the Company's next distribution rate case (Exh. DPU-NG 1-1).

adjustment factors and grid-facing smart grid pilot program costs from its distribution customers through smart grid distribution adjustment factors, and approved an allocation methodology between the two components for shared capital expenses.[94] The Department allowed for the recovery of all capital investments associated with the smart grid pilot program over a five-year period, as well as the recovery of incremental O&M costs. D.P.U. 11-129, at 94-102.

National Grid proposes to roll the smart grid pilot program costs into base distribution rates (Exh. NG-RRP-1, at 94). For capital items, the Company proposes to roll into rate base items that were used and useful as of the end of the test year (i.e., December 31, 2017), using depreciation and ADIT levels that reflect the end of the of the rate year (i.e., September 30, 2020) (Exh. NG-RRP-2 (Rev. 4), Sch. 11, at 1, 3; WP NG-RRP-2 (Rev. 4), at 5). The Company's proposal results in the addition of approximately $3,956,650 to the annual revenue requirement through the Company's return on rate base (Exhs. NG-RRP-2 (Rev. 4), Sch. 1, at 1 & Sch. 11, at 1, 3; WP NG-RRP-2 (Rev. 4), at 5). In addition, the Company proposes to include in base distribution rates test-year-end depreciation expense, property taxes, and O&M expense related to the smart grid pilot

94 The smart grid pilot program's customer-facing component included a dynamic pricing, or smart pricing, program as well as the installation of advanced metering infrastructure and in-home energy management technologies. D.P.U. 11-129, at 4, 57, 62. The smart grid pilot program's grid-facing component included the deployment of advanced distribution automation and control, automated distribution system monitoring technologies, fault location devices, and advanced capacitors on the Company's electric distribution system within the smart grid pilot program area. D.P.U. 11-129, at 4, 57, 62.

program (Exhs. AG 16-7 (Supp.), Att.; DPU-NG 15-10, Att.; DPU-NG 5-3; DPU-NG 27-1).

B. Position of the Parties

On brief, the Company reiterates its proposal to roll into rate base the cumulative capital investment made in relation to the smart grid pilot program through December 31, 2017 (Company Brief at 157). The Company states that these investments will be rolled into rate base effective October 1, 2019 (Company Brief at 157). No other party commented on this issue on brief.

C. Analysis and Findings

The Department currently has six open dockets related to the Company's smart grid pilot program: Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 14-109 (2012 and 2013 cost recovery); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 15-21 (2014 cost recovery); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 16-28 (2015 cost recovery); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 17-53 (2016 cost recovery); Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 18-28 (stranded 2015 and 2016 cost recovery, invoiced in 2017); and Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 18-29 (2017 cost recovery). To date, the Department has not ruled on the prudency of the Company's smart grid pilot program investments in those dockets. Given that there are a number of open dockets related to smart grid pilot program cost recovery and that the smart grid pilot program just concluded in December 2018, the

Department does not find it appropriate to include smart grid pilot program investments in base distribution rates at this time.

In addition, rolling customer-facing costs into base distribution rates is inconsistent with the cost recovery requirements established by the Department. The smart grid pilot program recovery is outlined in two tariffs: M.D.P.U. No. 1342 (smart grid adjustment provision) and M.D.P.U. No. 1341 (tariff for basic service). The smart grid adjustment provision, which addresses grid-facing[95] cost recovery through the smart grid distribution adjustment factors, is charged to all customers. M.D.P.U No. 1342, Sheet 1. By contrast, the tariff for basic service, which includes provisions that addresses customer-facing[96] pilot costs through the smart grid customer cost adjustment factors, is only charged to customers on basic service. M.D.P.U. No. 1341, § 9(a). The decision to recover smart grid pilot program costs through two separate tariffs was established in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-32, at 92-93 (2010), where the Department determined that it was inappropriate for customers who were not served via basic service to be responsible for customer-facing costs. The Company's proposal in the instant proceeding would have all customers pay for customer-facing investments, which make up

---

95 Distribution grid-facing technologies are those that are intended to improve the operating efficiency and reliability of the distribution grid, while at the same time providing the foundation necessary to enable greater numbers of distribution resources. D.P.U. 11-129, at 4, 11; Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 09-32, at 11 (2010).

96 Customer-facing technologies refers to the advanced digital meters and in-home customer information and energy management technologies accompanying the dynamic pricing program. D.P.U. 11-129, at 4, 7-8; D.P.U. 09-32, at 8.

the bulk of the costs related to the pilot program (Exhs. DPU-NG 5-1, at 2; DPU-NG 5-4; DPU-NG 15-3). We, therefore, find the Company's proposal to be inconsistent with the cost recovery requirements established by the Department.

Further, the Department does not intend for cost recovery of the Company's smart grid pilot program investments to continue beyond the term of the pilot. The Department established a five-year depreciation rate on all capital investments so that customers would not be paying for these investments long after the smart grid pilot program concluded. D.P.U. 11-129, at 99; D.P.U. 09-32, at 89-90. By including these investments in base distribution rates, cost recovery of these investments would continue well beyond the conclusion of the smart grid pilot (Exh. DPU-NG 5-3(a)). Moreover, given that the smart grid pilot has ended, the Department finds it inappropriate to establish a test-year level of O&M costs associated with the pilot program included in base distribution rates (Tr. 7, at 995-996).

For these reasons the Department does not approve National Grid's proposal to roll smart grid pilot program costs into base distribution rates. Accordingly, the Department directs National Grid to remove all costs associated with its smart grid pilot program from the Company's revenue requirement. Therefore, the Department directs the Company to decrease O&M expense by $2,062,076, decrease labor expense by $104,968, decrease property taxes by $165,927, decrease utility plant by $20,602,648,[97] decrease accumulated

[97] In Exhibit AG 16-7 (Supp.), Att., utility plant for smart grid pilot program projects is listed at $20,588,919 (Exh. AG 16-7 (Supp.), Att.). The Department has reviewed Exhibit NG-RRP-2 (Rev. 4), Sch. 6, at 1, and found that the Company omitted plant

depreciation by $17,204,979, increase ADIT by $80,686, and decrease amortization by $677,223 (Exhs. NG-RRP-2 (Rev. 4), Sch. 6, at 1-2; WP NG-RRP-2 (Rev. 4), at 6; AG 16-7 Att. (Supp.); RR-DPU-19; RR-DPU-20, Att.; RR-DPU-21, Att.). The Department will work to conclude the open dockets tied to the cost recovery of smart grid pilot investments in a forthcoming Order(s), and the Company should expect to recover all smart grid pilot program costs deemed to be eligible for cost recovery by the Department through the existing cost recovery mechanisms.

VIII. OPERATION AND MAINTENANCE EXPENSES

A. Employee Compensation

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

account 365.01 "Overhead Conductors and Devices" and subsequently added the $13,728 to the smart grid pilot program utility plant total, producing a utility plant balance of $20,602,648.

components of a company's employment compensation package, however, will be appropriately left to the discretion of a company's management. D.P.U. 92-250, at 55-56.

A company is required to provide a comparative analysis of its compensation expenses to enable a determination of reasonableness by the Department. D.P.U. 96-50 (Phase I) at 47. The Department evaluates the per-employee compensation levels, both current and proposed, relative to the companies in the utility's service territory 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-MPH-1, at 5). The Total Rewards Program encompasses base pay, variable pay, medical and dental insurances, life and long-term disability insurances, vacation and holiday pay, a pension plan, a 401(k) plan,[98] and other post-retirement benefits (Exh. NG-MPH-1, at 5-6, 23-24).[99]

2. Union Wages

a. Introduction

During the test year, National Grid booked $70,932,253 in payroll expenses for union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2 (Rev. 4),

98 A 401(k) plan is a retirement savings sponsored by an employer an organized under the requirements of the Internal Revenue Code. 26 UCS § 401(k).

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

Sch. 12, at 4-6). For union payroll expenses, $59,735,276 was directly incurred, $8,842,354 was allocated from NGSC, and $2,354,623 was allocated from other National Grid affiliates (Exhs. NG-RRP-2 (Rev. 4), Sch. 12, at 4, line 8; NG-RRP-2 (Rev. 4), Sch. 12, at 5, line 12; NG-RRP-2 (Rev. 4), Sch. 12, at 6, line 12). 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-MPH-1, at 14-15). Accordingly, the Company increased its test-year union payroll expense by $7,703,001, attributable as follows: (1) $6,536,527 in direct costs; (2) $1,023,918 allocated from NGSC; and (3) $142,556 from National Grid affiliates (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4-6).[100]

b. Positions of the Parties

National Grid claims that union wage increases are set through the collective bargaining process, involving negotiations between the Company and its union employees to establish wages, benefits, and conditions of employment (Company Brief at 261, citing Exh. NG-MPH-1, at 14). The Company maintains that union wages included in its revenue requirement include wage increases through April 1, 2020[101], which are already committed to union employees by virtue of the currently effective collective bargaining agreements (Company Brief at 261-262, citing Exh. NG-MPH-1, at 14-15; RR-DPU-9, Att.). The

---

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

[101] April 1, 2020 represents the midpoint of the rate year, which is the twelve months following the effective date of the rates established with the issuance of Department's final Order in this proceeding.

Company notes that International Brotherhood of Electrical Workers ("IBEW") Local 97's collective bargaining agreement expires on March 28, 2020, and, thus, the Company included a placeholder assuming a new contract will be in place (Company Brief at 262).

The Company argues that, to determine whether these rates are competitive with the market, it compared hourly union wages to the hourly pay rate from surrounding utilities (Company Brief at 262, citing Exh. NG-MPH-8). National Grid contends that this analysis shows that the hourly rates paid to National Grid union employees are within the range of these other utilities (Company Brief at 262, citing Exh. NG-MPH-8). As a result, the Company asserts that it demonstrated that the union wage levels included in the revenue requirement calculation are reasonable (Company Brief at 262). 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.

In this proceeding, April 1, 2020 represents the midpoint of the rate year. Only wage increases that are scheduled to occur prior to the midpoint of the rate year are eligible for recovery in base distribution rates. The Department finds that, for the union contract for United Steelworkers ("USW") Local 12431, the Company included an increase effective June 8, 2020, which is after the midpoint of the rate year (Exh. WP NG-RRP-5 (Rev. 4), at 12). Therefore, the Department denies National Grid the costs associated with the 2.75-percent increase effective June 8, 2020 for USW Local 12431.

In addition, the Company stated that it signed a new contract for Transport Workers Union ("TWU") Local 101 effective October 16, 2019; however, the Company failed to provide documentation of the wage increase for the agreement reached with TWU Local 101 (Company Brief at 262).[102] Further, the record shows that the contract for IBEW Local 97 has not yet been executed and the proposed amounts are simply placeholders (Tr. 7, at 1014-1015). Based on these factors, any post-test-year wage adjustments for these two unions are not known and measurable. Given that the wage increases are neither known nor measurable, the Department denies National Grid the costs associated with the 2.75-percent wage increase for TWU Local 101 assumed to take effect October 16, 2019, and the 2.5-percent wage increase for IBEW Local 97 assumed to take effect on March 29, 2020.

The Company's remaining proposed adjustments relate to increases effective before April 1, 2020, the midpoint of the first twelve months after the Department's Order in this proceeding, including the union payroll increases that occurred in 2018 and 2019 based on

---

102 While the Company maintains on brief that a three-year agreement was reached with TWU Local 101, it did not cite to any record evidence for support (Company Brief at 262).

signed collective bargaining agreements between the Company and the respective unions (Exhs. NG-MPH-1, at 14-15; DPU-NG 33-1 (Supp.), Att.; RR-DPU-9, Att.).

Further, 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-MPH-8). 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-MPH-8). Thus, we find that the Company has demonstrated the reasonableness of the union wage increases.

Based on the above, the Department finds that National Grid has demonstrated, except for the June 8, 2020 2.75-percent increase for USW Local 12431, the 2.75-percent increase for TWU Local 101, and the placeholder 2.5-percent expected wage increase for IBEW Local 97, the following: (1) the union salary increases are scheduled to become effective no later midpoint of the rate year; (2) there is sufficient documentation granting union wage increases that are scheduled to occur after the date of this Order; and (3) the union wage increases are reasonable. Accordingly, the Department denies a combined $153,088 associated with the three increases referenced above (Exhs. NG-RRP-2 (Rev. 4), Schs. 8, 12, 14, 15; WP NG-RRP-5 (Rev. 4), at 13). This $153,088 reduction to the cost of service represents a $140,166 decrease to wages, a $1,364 decrease to group life insurance, a $5,603 decrease to thrift costs, and a $5,955 decrease to payroll taxes[103] (Exhs. NG-RRP-2 (Rev. 4), Schs. 8, 12, 14, 15; WP NG-RRP-5 (Rev. 4), at 13).[104]

3. Non-Union Wages

a. Introduction

During the test year, National Grid booked $73,009,794 in payroll expenses for non-union personnel, including base wages, variable pay, and overtime pay (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4-6). Of this booked amount, $7,042,558 was directly incurred, $65,493,948 was allocated from NGSC, and $473,288 was allocated from other National Grid affiliates (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4-6). The Company proposes to increase test-year non-union payroll expense by $8,306,804 to account for increases that were effective July 1, 2018, and October 1, 2018, in addition to raises effective July 1, 2019, all of which occurred after the end of the test year (Exh. NG-RRP-1, at 26). This proposed increase is comprised of the following: (1) $166,832 increase in direct costs; (2) $8,145,644

---

103 No party objected to the Company's proposed group life insurance, thrift costs, or payroll taxes. Except for the amounts disallowed here, the Department has reviewed the remaining group life insurance costs, thrift costs, and payroll taxes, and we find them to be appropriate.

104 To calculate these values, the Department adjusted Workpaper NG-RRP-5 (Rev. 4), at 12-13, to exclude the identified wage increases for USW Local 12431, TWU Local 101, and IBEW Local 97. This calculation resulted in lower weighted union wage increases. The new increases were then input in Exhibit NG-RRP-2 (Rev. 4), Sch. 12, at 4-6, which resulted in the revised union wage adjustments.

increase from NGSC; and (3) $5,672 decrease allocated from all other affiliated companies (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4-6).[105]

b. Positions of the Parties

National Grid claims that, in setting compensation and benefit levels, its strategy is focused on developing and delivering a market competitive compensation and benefit package that is reasonable, recognizes and rewards excellence, maintains fair and competitive market pay and benefits for employees, and encourages employees to improve skills while balancing the interests of customers with respect to cost containment (Company Brief at 260, citing Exh. NG-MPH-1, at 6). National Grid states that it aims to set pay at the median level of the marketplace (Company Brief at 260, citing Exh. NG-MPH-1, at 9). To determine median pay level, the Company asserts that it benchmarks certain positions within each salary band and compares overall pay for these benchmarks to the 50th percentile of overall pay for comparable jobs in similarly sized companies based on market surveys (Company Brief at 260, citing Exh. NG-MPH-1, at 9). National Grid states that pay increases, which it asserts have been historically granted annually, are awarded based on individual performance and a comparison to the 50th percentile of the marketplace (Company Brief at 260, citing Exh. NG-MPH-1, at 8). Based on the above considerations, National Grid asserts that it has demonstrated that the non-union salary increases are reasonable and should be approved by the Department (Company Brief at 261). No other party addressed this matter on brief.

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

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

In addition, 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 2009 (Exh. NG-MPH-7). Between 2009 and 2018, National Grid granted union wage increases between 2.5 percent and 3.5 percent, and non-union wage increases between 0.43 percent and 3.64 percent (Exh. AG 1-41, Att. 1). Based on this information, the Department finds that a sufficient correlation exists between union and non-union wage increases. Fitchburg Gas and Electric Light Company, D.P.U. 07-71, at 76-77 (2008); D.P.U. 87-59-A at 18.

With respect to the reasonableness of the non-union wages, the Company tests the competitiveness of their 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-MPH-1, at 11). Specifically, the Company aims to set pay at the median level of the marketplace (Exh. NG-MPH-1, at 9). 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-MPH-1, at 9). This comparison shows that for National Grid, non-union salary compensation is one percent below market median, while total compensation is one percent above the market median (Exh. NG-MPH-2, at 5). The Department finds that the Company has demonstrated that their total proposed compensation is competitive with the market median and, therefore, reasonable (Exh. NG-MPH-2, at 5).

The Company provided a management commitment letter stating that a 3.35-percent payroll increase for non-union employees will take effect on July 1, 2019 (Exh. DPU-NG 21-2, Att.). Based on this information, the Department finds that the July 1, 2019, non-union salary increase is scheduled to become effective prior to issuance of our Order and that there is a commitment by management to grant the increase.

Based on the above, the Department finds that National Grid has demonstrated the following: (1) that there is a historical correlation between union and non-union payroll increases; (2) that the non-union wage increases are reasonable; (3) that non-union salary increases are scheduled to become effective no later than six months after the date of the Department's Order; and (4) that there is an express commitment by management to grant a 3.35 percent non-union wage increase that is scheduled to occur prior the date of this Order. Accordingly, the Department allows the Company's adjusted non-union payroll expense.

4. Incentive Compensation

a. Introduction

There are three components to National Grid's incentive compensation program, which is known as the annual performance plan ("Performance Plan"): (1) performance metrics focused on overall company financial health, including earnings per share ("EPS"), and ROE; (2) performance metrics and goals focused on individual objectives; and (3) performance metrics and goals focused on improving customer deliverables such as customer satisfaction, safety, and reliability (Exh. NG-MPH-1, at 18-20).

For Band A and Band B employees, 40 percent of incentive compensation is based on individual performance, while the remaining 60 percent is based on financial performance (Exh. NG-MPH-1, at 19-20).[106] 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-MPH-1, at 4 n.1, 21).[107] For Band C through Band F employees, 50 percent of incentive compensation is based on the safety, reliability, and customer responsiveness components, and 50 percent of incentive compensation is based on

---

106 Band A refers to the Company's top officers, including jurisdictional presidents and senior vice presidents; Band B refers to less senior officers, e.g., vice presidents (Exh. NG-MPH-1, at 7).

107 For the 2017/2018 performance year, National Grid changed the structure of the Performance Plan (Exh. NG-MPH-1, at 19). As of April 1, 2017, officer (i.e., Bands A and B) payouts are tied to the achievement of financial objectives and individual objectives with a split of 60/40 (Exh. NG-MPH-1, at 19-20). Directors (i.e., Band C) will no longer have any financial objectives (Exhs. NG-MPH-1, at 19-20; NG-MPH-5).

the individual objectives component (Exh. NG-MPH-1, at 19-20).[108] For union employees, the individual objectives relating to customer satisfaction, safety, and reliability account for 100 percent of incentive pay (Exh. NG-MPH-1, at 19).

During the test year, National Grid booked $2,372,394 in incentive compensation for union employees, attributable as follows: (1) $2,110,249 in direct costs; (2) $186,426 allocated from NGSC; and (3) $75,719 allocated from other National Grid affiliates (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4-6). For union employees, National Grid proposes an increase of $135,237 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 $2,507,631 (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4, line 34, column (c), Sch. 12, at 5, line 43, Sch. 12, at 6, line 39, column (c)).

During the test year, National Grid booked $8,041,229 in incentive compensation for non-union employees, attributable as follows: (1) $545,932 in direct costs; (2) $7,451,540 allocated from NGSC; and (3) $43,757 allocated from other National Grid affiliates (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4-6). 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

---

[108] Bands C through F are designated as follows: (1) Band C is 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 to a director or manager; (3) Band E is for supervisors who have at least one direct report and who report to a director or manager; and (4) Band F is for general administrative staff (Exh. NG-MPH-1, at 7).

(Exhs. NG-RRP-1, at 20; NG-RRP-2 (Rev. 4), Sch. 12, at 3). The Company proposes an increase of $482,378 to the non-union incentive compensation for National Grid, based on (1) targeted results for the test year and (2) escalating incentive compensation expenses based on post-test-year wage increases, which result in a proposed incentive compensation expense for non-union employees of $8,523,607 for National Grid (Exh. NG-RRP-2 (Rev. 4), Sch. 12, at 4, line 34, column (d), Sch. 12, at 5, line 43, column (d), Sch. 12, at 6, line 39, column (d)).

b. Position of the Parties

The Company maintains that, for both its union and non-union employees, the Performance Plan is based on individual performance of the employee or targeted goals for safety, reliability, customer and community responsiveness, and cost control (Company Brief at 263, citing Exh. NG-MPH-1, at 18-19). At the same time, the Company asserts that the corporate objectives of the Performance Plan are linked to the U.S. business strategy and are built around three key areas: customers; communities; and people that will foster the enhancement of the Company's connection with its customers and stakeholders (Company Brief at 263-264, citing Exh. NG-MPH-1, at 18-19).

National Grid argues that using this approach aligns the employee's pay with the health and performance of the Company (Company Brief at 265). In addition, the Company maintains that the revenue requirement does not include the variable pay component for National Grid's Band A or B officers that is tied to the achievement of financial metrics (Company Brief at 265, citing Exh. NG-MPH-1, at 21).

The Company argues that incentive compensation is a necessary mechanism for the Company to remain competitive in the labor market (Company Brief at 265). Additionally, the Company states, variable pay gives employees a stake in the Company's performance and provides direct incentives for employees to strive to meet or exceed metrics tied to safe, reliable, and efficient performance (Company Brief at 265).

Based on the foregoing, the Company argues that it has demonstrated that the use of the Performance Plan is reasonable and works to the benefit of customers and, thus, should be allowed (Company Brief at 265). No other party commented on this issue on brief.

c. Analysis and Findings

The Department has traditionally allowed incentive compensation expenses to be included in a utility's cost of service if (1) the amounts are reasonable and (2) the incentive plan is reasonably designed to encourage good employee performance. D.P.U. 07-71, at 82-83; Massachusetts Electric Company, D.P.U. 89-194/195, at 34 (1990). 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 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 20; NG-RRP-2 (Rev. 4), Sch. 12, at 3). 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 (Rev. 4), Sch. 12, at 3). Based on our review of this evidence, the Department finds that National Grid has demonstrated that the costs associated with the Performance Plan 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-MPH-1, at 21; NG-MPH-4, at 1). National Grid has not sought to recover the variable pay component that is tied to the achievement of financial metrics for Band A and Band B non-union employees. Incentive payment to the employee in Band A and Band B is based on the employee's performance against pre-determined goals, such as evaluated by EPS, ROE, and value-added (Exh. NG-MPH-4, at 2). Individual performance is determined and evaluated by his or her manager (Exh. NG-MPH-4, at 1-2). Incentive payment for employees falling within Bands C through F is based instead on focus measures for U.S. business operations (customers, community, and people) and individual performance (Exhs. NG-MPH-1, at 19-20; NG-MPH-5). Thus, the Performance Plan encourages good employee performance directly by rewarding non-union employees for achieving personal goals and by contributing to the financial success of National Grid (Exhs. NG-MPH-1, at 4-5; NG-MPH-4; NG-MPH-5). Further, National Grid 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-MPH-1, at 18-19; NG-MPH-4, at 1; NG-MPH-5, at 1). Moreover, National Grid has provided comprehensive analyses of base salaries and target total compensation compared to the market (Exhs. NG-MPH-1, at 4; NG-MPH-2; NG-MPH-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, with the following exception. Based on the Department's finding above rejecting certain post-test-year union wage adjustments, the Department denies $3,187[109] of the proposed incentive compensation adjustment.

B. Financial Accounting Standard No. 112

1. Introduction

The Company records the cost of post-employment benefits provided to non-retired employees who are in an inactive work status, such as employees who are on long-term disability, pursuant to the requirements of Financial Accounting Standard No. 112

---

109 To calculate this value, the Department adjusted Workpaper NG-RRP-5 (Rev. 4), at 12-13 to exclude the rate year wage increases for USW Local 12431, TWU Local 101, and IBEW Local 97. This calculation resulted in lower weighted union wage increases. The new increases were then input in Exhibit NG-RRP-2 (Rev. 4), Sch. 12, at 4-6, which resulted in the revised union wage adjustments. Incentive compensation is one of those adjustments, and the $3,187 is included in the total wage adjustment in Section VIII.A.2.c., above.

("FAS 112") (Exh. NG-RRP-1, at 36-37).[110] The Company specified that these benefits include income replacement, life insurance, and health care benefits for the inactive employees and their dependents (Exh. NG-RRP-1, at 37). During the test year, the Company booked a negative $491,676 in FAS 112 expense (Exhs. NG-RRP-1, at 36; NG-RRP-2 (Rev. 4), Sch. 16). The Company proposed to increase these expenses such that its proposed cost of service would have $0 expense for FAS 112 expense (Exhs. NG-RRP-1, at 37; NG-RRP-2 (Rev. 4), Sch. 16).

The Company states that both the test-year average and the five-year average for FAS 112 expense were negative, because adjustments in any year can increase or decrease the reserve (resulting in a positive or negative expense) (Exh. NG-RRP-1, at 37). The Company emphasized that it does not expect decreases to the reserve to continue on a sustained basis (Exh. NG-RRP-1, at 37). Further, the Company stated that reflecting a negative accrued expense and the resulting positive income in the cost of service would not provide a reasonable representation of the long-term effect of providing benefits to inactive employees (Exh. NG-RRP-1, at 37). Thus, the Company incorporated a normalizing adjustment to FAS 112 expense to offset the negative amount (Exh. NG-RRP-1, at 37). This proposed normalizing adjustment results in a $0 FAS 112 expense incorporated in the Company's revenue requirement (Exhs. NG-RRP-1, at 37; NG-RRP-2 (Rev. 4), Sch. 16).

---

[110] FAS 112 establishes accounting standards for employers who provide benefits to former or inactive employees after employment but before retirement (referred to as post-employment benefits).

2. Position of the Parties

a. Attorney General

The Attorney General argues that the normalized five-year average FAS 112 expense should be included in the Company's revenue requirement (Attorney General Brief at 21). The Attorney General contends that the Department had concluded that the Company's FAS 112 expense "should be calculated based on a five-year average, taking into account fiscal year 2012 through fiscal year 2016" (Attorney General Brief at 21, citing D.P.U. 15-155, at 264). The Attorney General asserts that, in the present case, the Company again calculated a normalized five-year average based on fiscal years 2014-2018, resulting in a credit of $1,101,513 for FAS 112 (Attorney General Brief at 21, citing Exh. NG-RRP-2 (Rev. 3), Sch. 16, at 4). She asserts that rather than reflecting the normalized five-year average in its revenue requirement, the Company proposes a pro forma FAS 112 expense of $0 (Attorney General Brief at 21-22).

The Attorney General maintains that reasoned consistency requires that the Department apply the same rationale when utilities determine pro forma expense amounts based on historical averages (Attorney General Brief at 22, citing 367 Mass. 92, 104; 368 Mass. 780, 802. She contends that the Department should not allow the Company to include the normalized FAS 112 expense in its revenue requirement when that expense is positive and then turn around and exclude the normalized FAS 112 credit when the expense is negative (Attorney General Brief at 22, citing Duquesne Light Company v. Barasch, 488 U.S. 299, 315 (1989)). The Attorney General contends that the Company has not provided evidence to reflect that it is reasonable to expect that an increase to the reserve and a resulting positive expense will occur on a sustained basis over time either, as three of the last five years in the five-year average used by the Company show a negative expense (Attorney General Brief at 22, citing Exh. AG-DJE-1, at 6-7). Thus, the Attorney General maintains that the most reasonable expectation is that the average FAS 112 expense over time will be no more than $0 (Attorney General Brief at 23).

The Attorney General maintains that, based on this most reasonable expectation, it is inappropriate and inconsistent to include the five-year average in the revenue requirements when the five-year average is positive but then to include $0 in the revenue requirement when the five-year average is negative (Attorney General Brief at 23). The Attorney General contends that, in three out of the last five years, the Company charged customers $78,733, and the Company's shareholders, in fact, profited, since the expense was negative (Attorney General Brief at 23). She argues that the five-year average FAS 112 expense should be included in the Company's revenue requirement in the present case, as it was in D.P.U. 15-155 (Attorney General Brief at 23).

The Attorney General asserts that including the five-year average FAS 112 expense reduces the pro forma test-year O&M expense by $1,101,513 (Attorney General Brief at 23). Further, the Attorney General contends that if the Department does not reflect the actual average FAS 112 expense in this case, when the five-year average is negative, then in future cases, it should not include FAS 112 expense in the Company's revenue requirement if the five-year average is positive (Attorney General Brief at 23-24).

b. Company

The Company argues that the Department should disregard the Attorney General's recommendation and approve the Company's proposal to use a $0 expense amount when the five-year FAS 112 average is negative (Company Brief at 193). The Company states that its proposal is consistent with Department precedent (Company Brief at 193). National Grid asserts that in D.P.U. 17-170, at 111, the Department agreed with the Company's affiliates Boston Gas and Colonial Gas Company ("Colonial Gas") that they would not expect continuing decreases to the reserve and the resulting negative expense on a prolonged basis, nor the resulting positive income in the cost of service (Company Brief at 193).[111] The Company asserts, in that proceeding, the Department found that the minimum expected cost for FAS 112 for ratemaking purposed would be $0 (Company Brief at 193, citing D.P.U. 17-170, at 111).

The Company maintains that the argument of the Attorney General that FAS 112 would be expected to be negative or no more than $0 in the future is based on a short period of history (Company Brief at 194). The Company argues it has demonstrated that, contrary to the Attorney General's claim, FAS 112 is not expected to be negative over the long-term (Company Brief at 194, citing Exhs. NG-RRP-Rebuttal-1, at 4-6; NG-RRP-Rebuttal-2; NG-RRP-Rebuttal-4). The Company asserts that the record was updated after the initial filing with an additional year of actuarially determined FAS 112 expense for the Company's

111 The Company applies the same accounting and ratemaking treatment for FAS 112 expense as Boston Gas and Colonial Gas Company.

fiscal year ended March 31, 2019, which was a positive expense for the second year in a row, and for three of the last six years (Company Brief at 194). The Company states that further record evidence reflecting a longer view of history showed that FAS 112 expense was positive six of the last nine years (Company Brief at 194). The Company contends that FAS 112 is normally a positive expense as opposed to negative expense as the record has shown, although FAS 112 expense can be negative in certain years due to claimant experience, an increase in the discount rate, and changes for other assumptions (Company Brief at 194, citing Exh. NG-RRP-Rebuttal-1, at 5). Additionally, National Grid asserts that the Attorney General's claim also fails to recognize that FAS 112 benefits paid to inactive employees increase over time (Company Brief at 194).

Lastly, the Company asserts that the Attorney General's claim that the Company has profited for the positive allowance approved in D.P.U. 15-155 as compared to the amount of expense it has incurred is false (Company Brief at 194). The Company maintains that it demonstrated that the positive rate allowance that it has been collecting for FAS 112 expense has been insufficient since rates went into effect on October 1, 2016, and that the Attorney General either chose to ignore the facts or did not see the Company's calculations (Company Brief at 194, citing Exh. NG-RRP-Rebuttal-5).

The Company maintains that a negative accrued expense resulting in positive income in the cost of service is not a reasonable assumption about the long-term effects of providing post-employment benefits, and, thus, the Company has made an appropriate adjustment by setting the level of FAS 112 expense in the cost of service to $0 (Company Brief at 195, citing Exh. NG-RRP-1, at 37). Accordingly, the Company contends the Department should (1) disregard the Attorney General's recommendation and (2) approve the Company's proposal to avoid an anomalous result (Company Brief at 195).

3. Analysis and Findings

The Company's FAS 112 expenses are volatile in nature, as they are affected by the actuarial assumptions employed to arrive at the annual level of expense (Exh. NG-RRP-Rebuttal-1, at 4). D.P.U. 17-170, at 110; D.P.U. 15-155, at 263. These assumptions include the discount rate, mortality, termination rates, disablement rates for active employees, health care cost trend rates, and the cost of medical coverage (Exh. NG-RRP-Rebuttal-1, at 4). D.P.U. 17-170, at 110; D.P.U. 15-155, at 263. Adjustments on these assumptions in any given year can increase or decrease the reserve resulting in a positive or negative expense (Exh. NG-RRP-1, at 37).

While the Department previously has found that it is appropriate to calculate FAS 112 expense for ratemaking purposes by taking a five-year average, the Department also has allowed normalizing adjustments to FAS 112 expense to offset the negative expense amount when the test-year average and the five-year average for FAS 112 expenses are negative. D.P.U. 17-170, at 111; D.P.U. 15-155, at 264. Based on the historical FAS 112 expense over the Company's last nine fiscal years, the Department finds that the Company recorded a positive expense for the second year in a row with a positive FAS 112 expense during fiscal year 2019 as well as for six of the last nine fiscal years (Exh. NG-RRP-Rebuttal-4). The normalizing adjustment to zero out the remaining test-year balance in order to offset the negative FAS 112 expense is consistent with the Department's finding in D.P.U. 17-170, at 111, stating that we would not expect continuing decreases to the reserve and the resulting negative expense on a prolonged basis, nor the resulting positive income in the cost of service (Exh. NG-RRP-1, at 37). As such, the minimum expected cost for FAS 112 for ratemaking purposes would be \$0. Therefore, the Department allows the proposed normalization adjustment to FAS 112 expense to offset the negative expense amount for the Company (Exh. NG-RRP-2 (Rev. 4), Sch. 16). The result is a \$0 FAS 112 expense in the Company's cost of service.

C. Health Care Expenses

1. Introduction

During the test year, National Grid booked \$19,478,081 in health care expenses (Exh. NG-RRP-2 (Rev. 4), Sch. 13, at 1). The Company then made a normalizing adjustment to test-year health care expense to redistribute major storm costs, which resulted in a \$608,699 reduction to health care expense (Exh. NG-RRP-2 (Rev. 4), Sch. 13, at 1, 3). This adjustment resulted in an adjusted test-year health care expense of \$18,869,382, of which \$8,958,421 were direct costs, \$9,732,393 was allocated from NGSC, and \$178,568 was allocated from other National Grid affiliates (Exh. NG-RRP-2 (Rev. 4), Sch. 13, at 1).

National Grid further proposed revisions for an increase of \$452,116, of which \$1,438,642 was directly allocated, and a reduction of \$986,526 attributed to NGSC (Exh. NG-RRP-2 (Rev. 4), Sch. 13, at 2). The Company's proposed adjustments to test-year health care expense reflect changes based on the Company's individual plan cost rates that will be in effect for calendar year 2019 (Exh. NG-RRP-1, at 30). The Company calculated these adjustments by: (1) calculating an average health care expense per employee using the 2019 working rates;[112] and (2) multiplying that amount by the number of enrolled employees as of January 1, 2018 (Exhs. NG-RRP-1, at 30). The total amount calculated is allocated to O&M, and the NGSC portion is further allocated to MECo and Nantucket Electric (Exh. NG-RRP-1, at 30). The resulting health care expense, after adjustments, is $19,321,498 (Exh. NG-RRP-2 (Rev. 4), at 2).

2. Positions of the Parties

a. Attorney General

The Attorney General presents two arguments regarding the Company's health care expenses (Attorney General Brief at 35). First, the Attorney General argues that the Department should use the Company's actual claims for 2018 as the basis for the pro forma health care expense included in the cost of service (Attorney General Brief at 36, citing RR-AG-11; RR-AG-35). She states that the Company's proposed pro forma adjustments to its test-year medical expenses are based on projected claims data for 2018, and that the Company has provided its actual 2018 claims data, which are significantly lower than the Company's forecasts (Attorney General Brief at 35). The Attorney General contends the Department should utilize the Company's actual 2018 claims data in determining the

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

Company's cost of service because these are the costs that the Company actually incurred, not an estimate (Attorney General Brief at 36).

Second, the Attorney General argues that the Department should reject the Company's proposed health care growth rate for the pro forma medical care expense included in the cost of service, because the growth rates the Company proposes are beyond credible growth rates that have been observed in the market (Attorney General Brief at 36). The Attorney General asserts that the Company's working rate health care growth rate is 6.4 percent for each of the years 2018 and 2019 (Attorney General Brief at 36, citing Exh. NG-MPH-10, Sch. 1, at 1). The Attorney General also maintains that general inflation in the economy has been less than two percent and even Mercer,[113] which conducted the Company's underwriting, found that employer's health care costs in 2019 for all sized employers are growing at 5.3 percent, before plan changes (Attorney General Brief at 36, citing Exh. AG-3).

The Attorney General argues that, as support for the Company's 6.4-percent forecasted health care growth rate, the Company simply provided an isolated bar graph from "the complete Mercer Study," without explanation of "the complete Mercer Study" (Attorney General Brief at 37, citing Exh. AG-3; RR-AG-11, Att. 5). Additionally, the Attorney General states, the 6.2-percent referenced in RR-AG-11-5, Att. is the increase in employers' health care costs for 2018 before plan changes for employers with 500 or more employees and that this rate is slightly below the 6.5-percent expected increase in employers' health care cost for 2018 before plan changes for all sized employers (Attorney General Brief at 37,

---

113 Mercer is a part of Marsh & McLennan, a professional services firm.

citing Exh. AG-3, at 3). She asserts that the Company's 6.4-percent rate is for expected health care costs for 2019 and argues that comparing this rate to the 2018 rate of 6.2 percent is not a fair comparison because they are different years (Attorney General Brief at 37, citing Exh. NG-MPH-10, Sch. 1; Tr. 4, at 547; AG-3; RR-AG-11, Att. 5). The Attorney General maintains, for all sized employers, the expected increase before plan changes dropped from 6.5 percent in 2018 to 5.3 percent in 2019 and argues that the Company's rate should follow suit, dropping to 5.3 percent, or lower considering employers with 500 or more employees had a lower rate in 2018 (Attorney General Brief at 37, citing Exh. AG-3).

Thus, the Attorney argues, the Company failed to provide support for the significant increase and that the Department should deny the Company's proposed medical increases based on the 6.4-percent health care growth rate (Attorney General Brief at 37). The Attorney General proposes that, although still higher than inflation, the Department should use the 5.3-percent growth rate, as it is in line with actual growth rate experience and is more reasonable (Attorney General Brief at 37, citing RR-AG-11; RR-AG-35).

b. Company

The Company explains that it is self-insured (Company Brief at 271). The Company states that National Grid USA employs a complex annual process to set working rates for its operating companies, including the Company, to budget for health care costs (Company Brief at 271, citing Exh. NG-MPH-1, at 37). National Grid asserts that on an annual basis its benefits consultant develops working rates for the next calendar year for budgeting and plan administration purposes in the same manner that health insurance premiums would be calculated (Company Brief at 271, citing Exh. NG-MPH-1, at 37). Additionally, the Company maintains that the working rates used for budget and plan administration purposes are not derived through forecasting assumptions relying on a "broad-based pool of insured parties," but rather are sufficiently correlated with the Company's own experience to support the Company's health care expense per the Department's finding in D.P.U. 15-155 (Company Brief at 272, citing Exh. NG-MPH-1, at 37).

The Company maintains that its working-rate methodology was approved by the Department, consistent with the actual computation of working rates used in the business, in D.P.U 10-55, D.P.U. 15-155, and D.P.U. 17-170 (Company Brief at 270 & n.65, 272). The Company asserts that this method consistently incorporates the most recent, available twelve months of calendar year actual claims data adjusted for plan design changes, 24 months of market trend, and demographic changes and other components reflected on Schedules 1 and 2 of Exhibit NG-MPH-10 (RR-AG-11) (Company Brief at 272).

The Company contends that the Department should reject the Attorney General's claims that National Grid has inflated health care expense projections, which result in an overstatement of its future costs (Company Brief at 270). The Company asserts that rate allowances for these types of cost, which can vary significantly from year to year, are rarely, if ever, based on a single year of cost that might be arbitrarily high or low (Company Brief at 271). In addition, the Company argues that there is no evidence suggesting that the Company's actual claims cost in 2018 is a valid representation of the Company's actual or expected cost in future years, nor does the Attorney General attempt to make any such showing (Company Brief at 271). The Company argues that the Attorney General's recommendation to utilize 2018 actual costs does not represent a bona fide expectation of cost and is an oversimplification of the process (Company Brief at 272).

The Company confirms that while the actual health care claims for calendar year 2018 were lower than the claims experienced in 2017, there is no basis to conclude that this lower claim rate will continue into the future (Company Brief at 272). National Grid argues that the working rates take a more holistic view of the market beyond cherry-picking a single calendar year as the Attorney General recommends (Company Brief at 272). The Company reiterates that the Attorney General has provided no evidence why calendar year 2018 should be utilized, and the Company argues that the Department should approve the Company's methodologically sound working rate (Company Brief at 273).

Additionally, the Company asserts that the Department should reject the Attorney General's proposed health care growth rate (Company Brief at 273). The Company states that, in an effort to contain health care costs, the Company transitioned to a self-insurance platform (Company Brief at 273, citing Exh. AG 1-52). National Grid maintains that transitioning to self-insurance eliminates the cost risk and margin charges of coverage through an insurance carrier and results in the Company's paying claims only where there is actual utilization of the insurance by employees and their dependents plus the administrative expense necessary for the plan administrators to pay claims (Company Brief at 273).

The Company argues that the Attorney General's documentation, used to show that health care costs are growing in 2019 for all-sized employers at a growth rate of 5.3 percent, is based on 1,566 preliminary responses to the national survey of employer-sponsored health plans; however, there is no indication whether the responses include any utility companies, nor which companies are included nor how many companies are in Massachusetts (Company Brief at 273, citing Exh. AG-3). The Company contends that including utility companies in the data is essential because utilities generally experience cost increases higher than average due to age of employees, family size, demographics and the type of work utility employees perform (Company Brief at 273, citing Tr. 4, at 583). Similarly, the Company asserts that including Massachusetts-based companies is necessary to develop a realistic picture of Company cost because Massachusetts is one of the highest-cost states for health care (Company Brief at 273-274, citing Tr. 4, at 584). National Grid states that, without knowing the composition of the data, the Attorney General's survey is not reliable as a source of data for the proposition she is making (Company Brief at 274). Based on the foregoing, the Company recommends that the Department should reject the Attorney General's proposal (Company Brief at 274).

3. Analysis and Findings

To be included in rates, health care 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; D.P.U. 91-106/91-138, at 53. Further, companies must demonstrate that they have acted to contain their health care costs in a reasonable, effective manner. D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; D.P.U. 92-78, at 29; D.P.U. 91-106/91-138, at 53. Finally, any post-test-year adjustments to health care expense must be known and measurable.

D.T.E. 01-56, at 60; D.P.U. 96-50 (Phase I) at 46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986).

As an initial matter, the Department finds that National Grid's health care expenses are reasonable and that the Company has taken reasonable and effective measures to contain these costs (Exh. NG-MPH-1, at 26-29). For example, National Grid is self-insured, which tends to produce costs savings (Exh. NG-MPH-1, at 26). Further, the Company conducts periodic 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-MPH-1, at 26-27). In addition, the Company's prescription drug program is now run by CVS Caremark, which provides prescription drugs at a lower cost by leveraging a volume discount (Exh. NG-MPH-1, at 27). The Company's medical benefit plan design changes included increased copays, deductibles, and out of pocket maximums, as well as the elimination of the waiver credit for opting out of medical coverage (Exh. NG-MPH-1, at 29-31).

Turning to National Grid's proposed post-test-year adjustment to health care expense, the Company maintains that the working rates provided by its benefits consultant are developed similarly to the historical insurance premiums that the Department accepts as the basis for post-test-year changes in health care insurance costs and, therefore, should be relied upon (Company Brief at 269-270). The Department agrees with the Company that using the working rates developed consistent with Company practice and Department precedent is appropriate. D.P.U. 17-170, at 103. In addition, contrary to the Attorney General's assertions, there is no evidence that the 2018 claims experience is a valid representation of the Company's actual or expected cost in future years.

The Department previously has denied recovery of pro forma health care 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-MPH-1, at 36-37). 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 experienced during the two years prior to the test year (Exh. NG-MPH-1, at 36). While evidence presented by the Attorney General shows that health care costs are increasing at a growth rate of 5.3 percent, the Department recognizes that there is no evidence to demonstrate whether the research includes any utility companies or how many companies are in Massachusetts (Exh. AG-3). The Department agrees with the Company that including utility companies is essential because utilities generally experience cost increases higher than average due to age of employees, family size, demographics, and the type of work utility employees perform (Tr. 4, at 583). Additionally, including Massachusetts based companies is necessary because Massachusetts is one of the highest-cost states for health care (Tr. 4, at 584). Therefore, we conclude that National Grid's proposed working rates, and corresponding growth rates, are sufficiently correlated to its own experience, rather than that of a broad-based pool of insured entities, to warrant their use in determining the Company's health care expense. D.P.U. 17-170, at 103;

D.P.U. 15-155, at 176-177. Thus, we accept the proposed working rates and corresponding growth rates. In conclusion, the Department accepts the Company's proposed health care expense of $19,321,498.

D. Rate Case Expense

1. Introduction

Initially, the Company estimated that it would incur $2,404,573 in rate case expense (Exhs. NG-RRP-1, at 75; NG-RRP-2, Sch. 4, at 2). Based on its final invoices and projected costs to complete the compliance filing, the Company proposes a total rate case expense of $2,790,731 (Exhs. NG-RRP-2 (Rev. 4), Sch. 4, at 2; DPU-NG 2-2 (Supp. 7), Att.). National Grid's proposed rate case expense includes costs related to legal representation, miscellaneous expenses associated with preparing the rate case (e.g., printing costs), and expert consulting services related to the Company's (1) PBR proposal, (2) compensation study, (3) allocated cost of service study ("ACOSS"), (4) marginal cost of service study, (5) depreciation study, (6) proposed ROE and capital structure, and (7) rate case support (Exh. NG-RRP-2 (Rev. 4), Sch. 4, at 2).

The Company proposes to amortize the rate case expense as a regulatory deferral over a five-year period (Exhs. NG-RRP-1, at 75; NG-RRP-2 (Rev. 4), Sch. 4, at 2). Amortizing the Company's proposed rate case expense of $2,790,731 over five years produces an annual expense of $558,146 (Exh. NG-RRP-1 (Rev. 4), Sch. 4, at 2).

2. Positions of the Parties

The Company maintains that it endeavored to contain costs by inviting vendors to participate in a competitive bidding process (Company Brief at 242, citing Exhs. DPU-NG 2-1; DPU-NG 2-4; DPU-NG 2-6 through DPU-NG 2-10). The Company asserts that its proposed five-year amortization period is consistent with its obligation to file a rate case every five years pursuant to G.L. 164, § 94 (Company Brief at 243, citing Exh. NG-RRP-1, at 75). In addition, the Company notes that the Attorney General did not object to the Company's calculation of its rate case expense (Company Brief at 243). The Company maintains that it has adhered to the Department's standards regarding rate case expense, and, therefore, the Department should approve the Company's proposed recovery (Company Brief at 243). No other party commented on this issue on brief.

3. Analysis and Findings

a. Introduction

The Department allows recovery for rate case expense based on two important considerations. First, the Department permits recovery of rate case expense that 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. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147; <u>Fitchburg Gas and Electric Light Company</u>, D.T.E. 02-24/25, at 192 (2002); D.P.U. 93-60, at 145. Rate case expense, like any other expenditure, is an area in which companies must seek to contain costs. D.P.U. 10-114, at 220; D.P.U. 07-71, at 99; D.T.E. 03-40, at 147-148; D.T.E. 02-24/25, at 192; D.P.U. 96-50 (Phase I) at 79. All companies are on notice that the risk of non-recovery of rate case expenses looms should they fail to sustain their burden to demonstrate cost containment associated with their selection and retention of outside service providers. D.P.U. 10-114, at 220; D.P.U. 09-39, at 289-293; D.P.U. 09-30, at 238-239; D.T.E. 03-40, at 152-154. Further, the Department has found that rate case expenses will not be allowed in cost of service where such expenses are disproportionate to the relief being sought. D.P.U. 10-114, at 220; D.P.U. 10-55, at 323; <u>see</u> <u>also</u> D.P.U. 93-223-B at 16-17.

b. <u>Competitive Bidding Process</u>

i. <u>Introduction</u>

The Department has consistently emphasized the importance of competitive bidding for outside services in a petitioner's overall strategy to contain rate case expense. <u>See</u>, <u>e.g.</u>, 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 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 the following: (1) legal services; (2) PBR proposal; (3) compensation study; (4) ACOSS; (5) marginal cost of service analysis; (6) depreciation study; (7) proposed ROE and capital structure; and (8) rate case support (Exhs. NG-RRP-2 (Rev. 4), Sch. 4, at 2; DPU-NG 2-1; DPU-NG 2-1 (Supp. 2)). National Grid provided documentation demonstrating that it conducted a competitive bidding process for each of its service providers, with the exception of the compensation survey provider and a rebuttal witness (Exh. DPU-NG 2-1 & Atts.).

Based on our review of the RFPs and responses, we conclude that National Grid's choices regarding its remaining consultants, including attorneys, were reasonable and cost effective (Exhs. DPU-NG 2-1, Atts. 1(a) through 6(b); DPU-NG 2-2 (Supp. 7), Att.; DPU-NG 2-3, Atts.; AG 32-1). We also find that National Grid gave proper consideration to price and non-price factors before selecting the providers that it determined would provide the best combination of price and appropriate quality of service (Exhs. DPU-NG 2-1, Atts. 1(a) through 6(b); DPU-NG 2-2 (Supp. 7), Att.; AG 32-1). For each category, the

Company appropriately selected a provider that possessed expertise and experience, knowledge of Department ratemaking precedent and practice, familiarity with the Company's operations, and a comprehensive understanding of the tasks for which it was requested to bid (Exhs. DPU-NG 2-1, Atts. 1(a) through 6(b); AG 32-1). Based on the foregoing, the Department concludes that National Grid conducted a fair, open, and transparent competitive bidding process for the remaining attorneys and consultants (Exhs. DPU-NG 2-1, Atts. 1(a) through 6(b); AG 32-1).

As noted above, the Company did not conduct a competitive bidding process for the service provider that conducted the compensation study. 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. The service provider that conducted the compensation study 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. See 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 the compensation survey service provider, and we find that the Company's selection of this provider was reasonable.

Finally, the Department is unable to conclude definitively that the Company conducted a competitive bidding process for one consultant who provided rebuttal testimony (Exhs. DPU-NG 2-1 & Atts.; DPU-NG 2-1 (Supp. 2), Att.). The service provider submitted a bid during the pendency of the proceeding, but it is unclear based on the record evidence whether that bid was in response to a competitive bidding process or whether that service provider was independently asked to submit a bid (Exh. DPU-NG 2-1 (Supp. 2), Att. at 26). 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. Further, we find that the scope of the testimony provided by the consultant was relevant to the issues presented in this proceeding and not unduly duplicative of evidence provided by other service providers (Exh. NG-NWA-Rebuttal-1; Tr. 6, at 801-817). Based on these considerations, the Department finds that in this instance, the Company's use of this consultant was reasonable.

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 the invoices are properly itemized (see, e.g., Exhs. DPU-NG 2-3, Atts. 2 through 7; DPU-NG 2-3 (Supp. 3), Atts. 2 through 4; DPU-NG 2-3 (Supp. 6), Atts. 2 through 8). In addition, 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-NG 2-3, Atts. 2 through 8; DPU-NG 2-3 (Supp. 5), Atts. 2 through 9; DPU-NG 2-3 (Supp. 7), Atts. 2 through 7).

In addition, the Company seeks to include miscellaneous costs of $23,647 as rate case expenses (Exhs. NG-RRP-1 (Rev. 4), Sch. 4, at 2; DPU-NG 2-2 (Supp. 7), Att.). These miscellaneous costs include expenses associated with printing filed materials and obtaining hearing transcripts (Exhs. DPU-NG 2-11; DPU-NG 2-3, Att. 10; DPU-NG 2-3 (Supp.), Att. 6; DPU-NG 2-3 (Supp. 6), Att. 7). The Department has reviewed the invoices provided by the Company for these miscellaneous costs and finds that such invoices are properly itemized (Exhs. DPU-NG 2-3, Att. 10; DPU-NG 2-3 (Supp.), Att. 6; DPU-NG 2-3 (Supp. 5), Att. 8; DPU-NG 2-3 (Supp. 6), Att. 7). In addition, the Department finds that these miscellaneous costs are reasonable and appropriate and were prudently incurred (Exhs. DPU-NG 2-3, Att. 10; DPU-NG 2-3 (Supp.), Att. 6; DPU-NG 2-3 (Supp. 5), Att. 8; DPU-NG 2-3 (Supp. 6), Att. 7).

d. Normalization of Rate Case

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 D.P.U. 15-155, at 244, the Department stated that the requirement in G.L. c. 164, § 94 for electric distribution companies to file rate schedules every five years effectively caps the normalization period at five years. In instances where a normalization period calculated pursuant to Department precedent results in a period greater than five years, the Department stated that we would, instead, use a five-year normalization period. D.P.U. 15-155, at 244. More recently in D.P.U. 17-05, at 281, however, the Department refined its findings in D.P.U. 15-155 and determined that the requirement in G.L. 164, § 94 to file rate schedules no less than every five years would not be treated as a de facto five-year cap on the normalization period. Instead, the Department stated that it will consider the G.L. 164, § 94 filing requirements together with the specific facts of the case to establish a normalization period that is a representative annual level of rate case expense to include in cost of service. D.P.U. 17-05, at 282.

Rather than propose a normalization period, National Grid proposes to amortize its rate case expense over a five-year period as a regulatory deferral (Exhs. NG-RRP-1, at 75; NG-RRP-2 (Rev. 4), Sch. 4, at 2). Such a proposal is in direct conflict with the Department's long-standing requirement that rate case expense be normalized rather than amortized. D.P.U. 96-50 (Phase I) at 77-78. Thus, we reject the Company's proposal to amortize its rate case expense as a regulatory deferral, and we will determine the appropriate normalization period for the allowed costs of $2,790,731.

The average interval between National Grid's last four rate cases is eight years.[114] As discussed in Section II.4., above, the Department has approved a PBR for the Company that includes a five-year term and stay-out provision. The Department has considered the term of a PBR in establishing an appropriate rate case expense normalization period. D.P.U. 17-05, at 281-282; D.P.U. 09-30, at 241; D.P.U. 07-71, at 105; D.T.E. 05-27, at 163-164; D.T.E. 03-40, at 163; D.T.E. 01-56, at 75; D.P.U. 96-50 (Phase I) at 78. In addition, the

---

114 In addition to the current filing, National Grid's last general electric rate cases were D.P.U. 15-155, D.P.U. 09-39, and D.P.U. 95-40. Based on the Company's filing dates for these last four rate cases, between D.P.U. 18-150 and D.P.U. 15-155, the interval is three years; between D.P.U. 15-155 and D.P.U. 09-39, the interval is 5.5 years; and between D.P.U. 09-39 and D.P.U. 95-40, the interval is 14.16 years. The sum of these intervals, divided by three and rounded to the nearest whole number results in a normalization period of eight years: 22.66/3 = 7.55 (rounded to eight)).

Department has found that the term of a PBR 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. Accordingly, the Department finds that a five-year normalization period is appropriate.

4. Conclusion

The Company has proposed and the Department has accepted a final rate case expense of $2,790,731 (Exh. NG-RRP-2 (Rev. 4), Sch. 4, at 2). 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 $558,146 ($2,790,731 divided by five years).

E. Joint Facilities Expense

1. Introduction

The Company presently occupies space at intercompany facilities in Amesbury, Massachusetts ("Amesbury"), Lincoln, Rhode Island ("Lincoln"), and Syracuse, New York ("Syracuse") (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-14; DPU-NG 27-17; DPU-NG 27-18). These joint facilities are operated by the Company's affiliates Boston Gas and Colonial Gas, The Narragansett Electric Company, and Niagara Mohawk Power Corporation, respectively (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-14; DPU-NG 27-17; DPU-NG 27-18). During the test year, the Company booked $3,462,528 in joint facilities expense (Exhs. NG-RRP-1, at 40; NG-RRP-2 (Rev. 4), Sch. 18, at 1; NG-RRP-5 (Rev. 4), at 2). The Company has proposed several changes to its test-year cost of service in this area. First, the Company proposed to decrease its test-year cost of service by $6,826 to remove fully amortized costs (Exhs. NG-RRP-1, at 40; NG-RRP-2 (Rev. 4), Sch. 18, at 3). Second, the Company proposed to decrease its test-year cost of service by $12,000 to remove prepayment of tower rental (Exhs. NG-RRP-1, at 40; NG-RRP-2 (Rev. 4), Sch. 18, at 3). Third, the Company proposed a decrease of $1,602,429, representing an adjustment that was made to remove a duplicate accounting entry to joint facilities expense (Exhs. NG-RRP-1, at 40; NG-RRP-2 (Rev. 4), Sch. 18, at 3). During the course of the proceeding, the Company proposed to reclassify a cost previously included in other O&M expenses related to the Syracuse joint facility, and add it to joint facilities expense, representing an increase of $17,351 (Exhs. NG-RRP-1, at 40; NG-RRP-2 (Rev. 4), Sch. 18, at 3; NG-RRP-5 (Rev. 4), at 2). These adjustments resulted in a total proposed joint facilities expense of $1,858,624 (Exh. NG-RRP-2 (Rev. 4), Sch. 18, at 4).

The Company also proposed to reclassify $28,100 and $45,949 for tower rentals related to the Company's smart energy solutions pilot program from joint facilities expense to other O&M (Exhs. DPU-NG 27-11; DPU-NG 27-12).[115] Lastly, the Company included a recalculation for Lincoln's joint facility expense, which showed an understatement of $42,391 in the initial amount (Exh. DPU-NG 27-17). In its final updated cost of service filing, the Company did not adjust its total proposed joint facilities expense for these two proposed reclassifications (Exh. NG-RRP-2 (Rev. 4), Sch. 18, at 2).

---

115 The Company initially labelled the $28,100 portion of tower rentals as solar phase II costs. During the course of the proceeding, the Company identified that these costs were mislabeled and are instead related to tower rentals for the Company's smart energy solutions pilot program (Exh. DPU-NG 27-11).

2. Positions of Parties

On brief, the Company summarized its revised calculation of joint facilities expense (Company Brief at 212). No other party addressed this issue on brief.

3. Analysis and Findings

The Department permits rate recovery of payments to affiliates where those payments are: (1) for activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a formula that is both cost effective in application and nondiscriminatory for those services specifically rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 95-118, at 41, citing Milford Water Company, D.P.U. 92-101, at 42-46 (1992); D.P.U. 85-137, at 51-52. In addition, 220 CMR 12.04(3) provides that: "An Affiliated Company may sell, lease, or otherwise transfer an asset to a Distribution Company, and may also provide services to a Distribution Company, provided that the price charged to the Distribution Company is no greater than the market value of the asset or service provided."

The Amesbury facility is used exclusively by operating affiliates in Massachusetts, and the rent expense is, therefore, allocated only to the Company from its gas company affiliates (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-14). The Company has provided rent allocation calculations for the Lincoln and Syracuse facilities (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-14; DPU-NG 27-17; DPU-NG 27-18). The Lincoln facility contains certain telecommunications, information services, and back-up dispatch equipment; the rent expense associated with this facility is allocated based on the square footage occupied by that equipment (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-13; DPU-NG 27-14). The Syracuse facility supports a number of service company groups that provide business services, such as accounts payable, employee services, billing and collections payroll, to numerous of National Grid's operating affiliates (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-13; DPU-NG 27-14). The Company has shown that the costs incurred for joint facilities expense are for activities that benefit the Company and that do not duplicate services already provided by the Company (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-13; DPU-NG 27-14). The Company also has provided the Department with a breakdown of the costs incurred and the Department is satisfied that incurring lease expense from affiliates is reasonable and a least-cost strategy (Exhs. DPU-NG 13-14, Att.; DPU-NG 27-13; DPU-NG 27-14). The Department, however, finds that the costs are not properly allocated to the Company because the proposed joint facilities expense relies in part on a carrying charge component that is determined using the different affiliates' weighed costs of capital (Exhs. NG-RRP-1, at 40; NG-RRP-2 (Rev. 4), Sch. 18; NG-RRP-5 (Rev. 4), Sch. 2; DPU-NG 13-14, Att.; DPU-NG 27-16; DPU-NG 27-17; DPU-NG 27-18). The Department has found that where a petitioning company pays a return component on a facility owned by an affiliate, customers of the petitioning company are forced to subsidize the operations of the affiliate. D.P.U. 17-05, at 220; D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 82-83. As such, the Department has limited the return component to the weighted cost of capital applicable to the petitioning company. D.P.U. 17-05, at 220; D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 82-83. Therefore, we will make several adjustments below.

For the Amesbury facility, the Company proposes a test-year expense of $98,597, calculated using the weighted cost of capital for its affiliates Boston Gas and Colonial Gas to arrive at the pre-tax rates of return of 11.182 percent for Boston Gas and 11.437 percent for Colonial Gas (Exhs. NG-RRP-2 (Rev. 4), Sch. 18, at 4; DPU-NG 13-14, Att. at 2; DPU-NG 27-16). Nonetheless, the appropriate charge is the Company's approved pre-tax rate of return of 9.49 percent to calculate its allocation of test-year joint facilities expense. This correction results in a joint facilities expense of $92,030 for the Amesbury facility (Exh. DPU-NG 13-14, Att. at 2).[116] Accordingly, we decrease the Company's proposed cost of service by $6,568.

For The Narragansett Electric Company affiliate facility in Lincoln, the Company initially proposed a test-year expense of $79,770 (Exhs. NG-RRP-2 (Rev. 4), Sch. 18, at 4; DPU-NG 13-14, Att. at 1). During the course of the proceeding, the Company recalculated the Lincoln joint facility expense, which showed an understatement of $42,391 in the initial amount, resulting in a total proposed expense of $122,161 (Exh. DPU-NG 27-17, Att. at 5). The Company calculated this amount using the weighed cost of capital approved for The Narragansett Electric Company, resulting in a pre-tax rate of return of 9.68 percent (Exh. DPU-NG 27-17, Att. at 1, 3). Using the Company's approved pre-tax rate of return

---

116 For the Amesbury facility, the $92,030 is derived using Exhibit DPU-NG 13-14, Att. at 2 and replacing the ROEs in Column M with 9.49 percent.

of 9.49 percent, as outlined above, results in a joint facilities expense of $121,144 for the Lincoln facility. The Company did not, however, include the increase of $42,391 in its revised cost of service update (see, e.g., Exhs. NG-RRP-2 (Rev. 2), Sch. 18, at 3; 4 NG-RRP-2 (Rev. 4), Sch. 18, at 3, 4). Accordingly, we increase the Company's cost of service by $41,374.[117]

For the Syracuse facility, the Company initially proposed a test-year expense of $1,572,650 (Exhs. NG-RRP-2 (Rev. 4), Sch. 18, at 4; DPU-NG 13-14, Att. at 1). During the course of the proceeding, the Company indicated that $17,351 related to its Syracuse facility should be reclassified from other O&M to joint facilities expense (Exhs. NG-RRP-2 (Rev. 4), Sch. 18; DPU-NG 13-14, Att. at 4). The Company, therefore, proposes a total of $1,590,001 related to the Syracuse joint facility expense, which is calculated using Niagara Mohawk Power Corporation's pre-tax weighed cost of capital of 10.69 percent (Exhs. NG-RRP-2 (Rev. 4), Sch. 18; DPU-NG 13-14, Att. at 4; DPU-NG 27-18, Att.). Using the Company's approved pre-tax rate of return of 9.49 percent, as outlined above, results in a joint facilities expense of $1,497,799 for the Syracuse facility.[118] Accordingly, we decrease the Company's proposed cost of service by $92,202.

---

117 For the Lincoln facility, the $121,144 is derived using Exhibit DPU-NG 27-17, Att. at 1 and replacing the ROE with 9.49 percent, which includes an adjusted amount for the revision that the Company did not include in its revised cost of service update.

118 For the Syracuse facility, the $1,497,799 is derived using Exhibit DPU-NG 27-18, Att. at 6 and replacing the pre-tax WACC in Row 7 with 9.49 percent.

Additionally, during the course of the proceeding, the Company indicated that some expenses were improperly included in joint facilities expense and should be reclassified to other O&M (Exhs. DPU-NG 27-11; DPU-NG 27-12). These expenses are comprised of $28,100 and $45,949 for tower rentals for the Company's smart energy solutions pilot program (Exhs. DPU-NG 27-11; DPU-NG 27-12). Although the Company stated that it would include these revisions in its updated cost of service, it did not include revisions related to the tower rentals in its updated cost of service (see, e.g., Exhs. NG-RRP-2 (Rev. 2), Sch. 18, at 3, 4; NG-RRP-2 (Rev. 4), Sch. 18, at 3, 4). While the Department recognizes that the Company proposal to reclassify these costs is appropriate, the Department has found in Section VII.C., above, that costs related to the smart energy solutions pilot program are not includable in base distribution rates. Therefore, the Department does not address these costs here.

The Department, therefore, approves a total decrease of $1,661,300, representing a decrease of $6,568 related to the change in the pre-tax rate of return for the Amesbury facility; an increase of $41,374 related to the Company's updates and the change in the pre-tax rate of return for the Lincoln facility; a decrease of $92,202 as a result of reclassification from other O&M for the Syracuse facility; the removal of the duplicate entry of $1,602,429; and the removal of amortized costs of $18,826 (Exhs. NG-RRP-1, at 43; NG-RRP-2 (Rev. 4), Sch. 18; NG-RRP-5 (Rev. 4), Sch. 2; DPU-NG 13-14, Att.; DPU-NG 27-11; DPU-NG 27-12; AG 3-10; AG 3-11). These adjustments result in joint facilities expense of $1,801,228 ($3,462,528 - $1,661,300). Consequently, the Department reduces the Company's cost of service by $57,396. As a result of this decrease, inflation expense related to joint facilities expense will be updated in Schedule 2a in Section XVIII.C., below.

F. Service Company Rents

1. Introduction

Service company rent expense represents charges billed to National Grid for capital costs incurred by NGSC[119] to develop and own IT that will be used on a shared basis by the Company and other National Grid USA subsidiaries (Exh. NG-RRP-1, at 38). NGSC capitalized property includes IT investments, such as hardware, software, databases, networks, shared facilities, and leasehold improvements, that are generally determined to benefit more than one company within the National Grid USA organization (Exhs. NG-ITP-1, at 6; DPU-NG 13-21; AG 1-92). Specifically, National Grid explained that the IT function at NGSC delivers three primary categories of services: (1) development/delivery services, which include the identification of new computer and communication technology trends and development of relevant innovative solutions for the business; (2) support and maintenance services, which involve ongoing support for business applications and infrastructure; and (3) end-user services, which include products and services such as desktop and email services, collaboration services, communications media,

[119] NGSC is a wholly owned subsidiary of National Grid USA. NGSC provides a variety of services to companies within the National Grid USA holding company system, including MECo and Nantucket Electric. These services include management, administrative, accounting, legal, engineering, and information systems (Exhs. NG-RRP-1, at 1; AG 1-26, Att. 2, at 41-42; AG 1-98, Att. at 1).

and printer/fax support (Exh. NG-ITP-1, at 6-7). National Grid categorizes its service company rent expense into two categories: (1) information systems and (2) facilities (Exhs. NG-RRP-2 (Rev. 4), Sch. 17, at 4; WP NG-RRP-7a (Rev. 4); WP NG-RRP-7b (Rev. 4); WP NG-RRP-7c (Rev. 4); WP NG-RRP-7d (Rev. 4)).

National Grid specified that NGSC owns the information systems and facilities capital assets and bills its affiliated companies, including National Grid, their respective allocated share of costs, known as rent expense (Exhs. NG-ITP-1, at 7, 9; NG-RRP-1, at 38; AG 1-92).[120] The Company explained that, consistent with National Grid USA's cost allocation manual, NGSC IT project costs are tracked for each project by work order, and an allocation code is utilized based on cost causation to properly allocate the costs to each respective operating company that derives a benefit from the investment (Exhs. NG-ITP-1, at 9; AG 1-92 & Atts.; AG 20-3). The allocated rent expense is composed of amortization/depreciation expense and a service company return component of 9.17 percent, which is based on NGSC's capital structure of 50 percent debt and 50 percent equity and the Company's own proposed 10.5-percent ROE (Exhs. NG-ITP-1, at 9; NG-RRP-1, at 39; WP NG-RRP-7a (Rev. 4), WP NG-RRP-7b (Rev. 4), WP NG-RRP-7d (Rev. 4), DPU-NG 6-5). The Company further explained that NGSC assets are amortized based on the use of a weighted average composite service life for each asset type; for instance, software applications are typically amortized over a period of 84 months (Exh. NG-ITP-1, at 9).

---

120 The Company calculated its proposed return component using NGSC's capital structure and the Company's 10.5-percent ROE proposed in this case (Exh. DPU-NG 6-5 & Att.).

National Grid explained that NGSC does not issue a paper copy or consolidated invoice to the operating companies that it serves (Exh. NG-ITP-1, at 18). Instead, NGSC issues a monthly billing report to the operating companies for services rendered, and a designated reviewer at the Company reviews the bills to identify errors and determine if the charges are appropriate (Exh. DPU-NG 13-28). National Grid further explained that service company rent expense appears on the billing report in a pool of expenses that also includes expenses other than service company rents, rather than having service company rent expense as a single line item (Exh. DPU-NG 13-28).

During the test year, NGSC charged National Grid $36,462,051 in service company rents (Exhs. NG-RRP-1, at 38; NG-RRP-2 (Rev. 4), Sch. 17, at 4). National Grid stated that it made a normalizing adjustment of ($5,073,206) to restate the allocation of service company rents to the Company based on a true-up of the return on and of capital calculations, which resulted in a normalized test-year service company rent expense of $31,388,845 ($29,149,588 in existing information systems projects and $2,239,257 in existing facilities) (Exhs. NG-RRP-1, at 38-39; NG-RRP-2 (Rev. 4), Sch. 17, at 4; DPU-NG 13-32). The Company then made a further adjustment to decrease the service company rents to the rate year amount. Specifically, the Company made an adjustment relating to new and existing IT projects and new and existing facilities of ($5,828,333), which resulted in a final requested service company rent, inclusive of post-test-year additions and adjustments to reflect rate-year balances, of $25,560,512 ($23,999,525 in information systems investments and $1,560,987 in facilities) (Exhs. NG-RRP-2 (Rev. 4), Sch. 17, at 2, 4; NG-ITP-1, at 11).[121]

2. Positions of the Parties

a. Attorney General

The Attorney General notes the significant increase in IT costs over the past decade and contends that due to the increasing investment in and importance of IT, regulators must closely track IT investments to ensure that projects benefit Massachusetts ratepayers (Attorney General Brief at 44-45, 51, citing Exh. AG-GLB-Surrebuttal-1, at 14; D.P.U. 09-39, at 158-159). Specifically, the Attorney General recommends that the Department direct National Grid to develop a comprehensive, Massachusetts-specific IT strategy and cyber security plan for future evaluation by the Department and interested stakeholders (Attorney General Brief at 45). The Attorney General presents several arguments in support of this recommendation.

The Attorney General contends that the Company's IT strategy document, which outlines National Grid plc IT strategies for the United States and United Kingdom, contains high-level descriptions and projected expenditures, and does not differentiate between IT costs that are subject to special ratemaking treatment, such as grid modernization and gas business enablement, and other core IT investments (Attorney General Brief at 47, citing

121 The information system investments of $23,999,525 is the sum of $20,510,125 for existing and $3,489,400 for new (Exh. NG-RRP-2 (Rev. 4), Sch. 17, at 4, Line 20 + Line 21). The facilities amount of $1,560,987 is the sum of $1,549,359 for existing and $11,628 for new (Exh. NG-RRP-2 (Rev. 4), Sch. 17, at 4, Line 22 + Line 23).

Exh. AG 30-1, Att. 2; Tr. 4, at 481-484; RR-AG-9, Att.). In addition, the Attorney General contends that the annual investment plan submitted by the Company is insufficient, consists of an accumulation of "disjointed documents," produces an annual portfolio of projects subject to continual change, and focuses on National Grid USA's New York service territory, rather than on investments pertinent to Massachusetts ratepayers (Attorney General Brief at 47-48, citing Exh. AG 30-1, Att. 2, at 18; RR-AG-8, Atts. 1, 5; RR-AG-9). The Attorney General asserts that the Company lacks a comprehensive, detailed, written plan prepared prior to project implementation and that National Grid approaches IT investments in a reactive, rather than proactive, manner (Attorney General Brief at 48, citing Exh. AG 30-1, Att. 2).

Next, the Attorney General contends that IT investments allocated to Massachusetts are not fully vetted to ensure that they are necessary and beneficial to the Company and its ratepayers because there is no Massachusetts-specific IT plan (Attorney General Brief at 50, citing Tr. 4, at 509-512). To support this argument, the Attorney General notes that, although sanctioning documentation associated with a project called community choice aggregation demonstrates that the investment was initiated in response to New York business needs, NGSC allocated 20.69 percent of project costs to MECo ratepayers (Attorney General Brief at 50-51, citing Exhs. AG 1-19, Att. 4, at 1-13; AG 13-20, Att. 1, at 5; Tr. 4, at 505-507, 512). The Attorney General contends that there is insufficient justification for how this project benefits National Grid ratepayers, and she further argues that sanctioning papers generally lack information regarding project prioritization and how proposed projects interact with one another and advance National Grid's broader IT strategy (Attorney General Brief at 51, citing Exh. AG-GLB-Surrebuttal-1, at 14).

Based on the above, the Attorney General asserts that National Grid should develop and submit to the Department, on an annual basis, a rolling three-year IT strategy and cyber security plan that identifies proposed IT projects scheduled for implementation in Massachusetts (Attorney General Brief at 51, citing Exh. AG-GLB-Surrebuttal-1, at 17). The Attorney General argues that the plan should describe how each investment advances the Company's corporate strategy with grid modernization investments clearly delineated from core IT investments (Attorney General Brief at 51-52, citing Exh. AG-GLB-Surrebuttal-1, at 17-18). The Attorney General further argues that the plan should include documentation for each project showing the need, scope, budget, alternatives considered, cost allocation, costs and benefits to Massachusetts ratepayers, along with variance analyses (Attorney General Brief at 51, citing Exh. AG-GLB-Surrebuttal-1, at 17). The Attorney General maintains that such a plan would ensure a more proactive, coordinated, and Massachusetts-focused approach to IT investments and, therefore, would allow a more meaningful review of IT investments by the Department and other stakeholders in future base distribution rate proceedings (Attorney General Brief 52, citing Exh. AG-GLB-Surrebuttal-1, at 19).[122]

[122] As discussed in Section XIV., below, the Attorney General suggests that the Department take into account the Company's "sustained lack of adequate planning in its IT investments" when considering the appropriate ROE for the Company in the instant case and consider setting the Company's ROE at the lower end of the range (Attorney General Brief at 52-53, citing, e.g., Exh. AG 30-1, Att. 2; D.P.U. 17-170,

In response to the Company's proposal to file an annual IT capital investment plan, as well as quarterly variance reports, the Attorney General argues that this proposal is a positive first step towards rectifying documentation shortcomings and would effectively demonstrate the Company's implementation of its long-term plan (Attorney General Reply Brief at 16, citing Company Brief at 210-211). The Attorney General maintains, however, that due to the Company's large-scale investment in IT, the Department should also direct the Company to prepare a Massachusetts-specific long-term IT investment plan (Attorney General Reply Brief at 16).

b. Company

National Grid argues that the Attorney General is incorrect in asserting that there is no Massachusetts-specific IT plan and that investments allocated to Massachusetts are not fully vetted to ensure that they are necessary and beneficial to the Company (Company Brief at 205). The Company maintains that the record demonstrates that National Grid has a robust IT investment plan involving collaboration between Massachusetts jurisdictional representatives and the NGSC IT team to determine the investments with the highest priority for investment for Massachusetts (Company Brief at 205-206, citing Exh. NG-ITP-1, at 7; RR-AG-8, Att. 5). The Company further explains that the resulting IT plan is thoroughly reviewed by various Company personnel, and National Grid claims that this process represents a best practice to engage end-users of IT services (Company Brief at 205-207, citing RR-AG-8, Att. 5). In addition, the Company asserts that the Attorney General's

---

at 205, 238-239; D.P.U. 15-155, at 303; D.P.U. 10-55 at 259; D.P.U. 85-266-A/271-A at 6-14).

characterization of the IT investment plan as subject to continual change is inapposite, and the Company explains that, while the process allows for flexibility in investment to respond to changing needs, these investments are still subject to a thorough review process (Company Brief at 207-208, citing RR-AG-8, Att. 5, at 10).

Further, the Company contends that the Attorney General's assertion that the Company's IT planning strategy is insufficiently focused on Massachusetts, and instead focuses on National Grid USA's New York service territory, is based on cherry-picked information (Company Reply Brief at 91, citing RR-AG-8, Att. 5). The Company argues that a review of the entire document reveals a number of investments aimed at benefiting the Company and its customers (Company Reply Brief at 91, citing RR-AG-8, Att. 5).

In response to the Attorney General's concern that the Company is not properly delineating between grid modernization investments and core business investments, National Grid maintains that it will establish separate lines of business associated with grid modernization work orders to distinguish this work in its accounting system (Company Brief at 209). The Company asserts that it will review any charges to this line of business, on a monthly basis, and remove any charges deemed unrelated to eligible grid modernization investments (Company Brief at 209).

The Company states that if the Department requires National Grid to file annual reports regarding progress under the annual IT investment plan, the Company recommends that it provide the Department with the same type of reporting and information that its affiliate Niagara Mohawk Power Corporation provides the New York State Department of

Public Service (Company Brief at 210). Specifically, the Company proposes to provide the Department with the following: (1) the IT capital investment plan for the upcoming rate year, including a narrative explaining the overall IT investment plan and identifying the proposed IT projects and their estimated costs; and (2) quarterly variance reports addressing the status of NGSC IT programs and budgets within 60 days after the end of each fiscal year quarter (Company Brief at 210-211). The Company states that the quarterly variance reports will include a narrative explaining the overall information systems investment plan, a description of defined program categories that form the spending rationale for IT projects, detail on budgets and actual spending for each of the program categories, including the top ten projects by budget within the program categories, variance analyses, identification of allocations to the Company, and a report on budget exceptions by program category and top ten projects based on allocations to the Company (Company Brief at 210-211).

3. Analysis and Findings

a. Introduction

The Department will first review the Company's proposal for test-year and post-test-year adjustments to service company rents. The Department will then examine the Attorney General's recommendation to direct the Company to file an annual, Massachusetts-specific, IT investment plan.

b. Information Systems and Facilities Rent Expense

A company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. D.T.E. 03-40, at 171; Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1989). The standard for inclusion of lease expense is one of reasonableness. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80 (Phase One) at 96 (1991). Further, in establishing rates for the companies under its jurisdiction, the Department relies on historical test-year data, adjusted for known and measurable changes. D.P.U. 1580, at 13-17, 19; D.P.U. 136, at 3; D.P.U. 19992, at 2; D.P.U. 18204, at 4; D.P.U. 18210, at 2-3; D.P.U. 18264, at 2-4.

National Grid has submitted supporting documentation for the costs and benefits of NGSC's allocated IT investments. Specifically, National Grid provided documentation detailing work order support, project descriptions, project sanctioning papers, project re-sanctioning papers if applicable, allocation codes for each project, project in-service dates, project closure papers, and variance analyses (Exhs. NG-ITP-2 (Rev. 1); NG-ITP-3 (Rev. 1); NG-ITP-4 (Rev. 1); DPU-NG 6-3 & Atts.; DPU-NG 6-4 & Atts. 1-2; DPU-NG 6-7 & Att.; DPU-NG 6-7 (Supp.) & Att.; DPU-NG 13-24 & Att.; DPU-NG 13-27 & Atts.; DPU-NG 13-27 (Supp.) & Atts.; DPU-NG 13-28 & Atts.; AG 1-19 (Supp.) & Atts.; AG 1-26, Att. 2; AG 1-92 & Atts.; AG 20-3, Att.; AG 30-1, Att. 1). National Grid has also provided sufficient detail regarding its project planning, sanctioning, and review process (Exhs. NG-ITP-1, at 7-8; AG 20-4; AG 30-1, Att. 2; RR-AG-8 & Atts. 1-5).

As summarized above, for the rate year, National Grid requests service company rents of $25,560,512, consisting of an allocated amount of depreciation/amortization expense and a return component for existing and post-test-year information systems projects and facilities (Exhs. NG-ITP-1, at 9; NG-RRP-1, at 39; WP NG-RRP-7a (Rev. 4), WP NG-RRP-7b

(Rev. 4), WP NG-RRP-7d (Rev. 4), DPU-NG 6-5). NGSC bases this calculation on NGSC's capital structure of 50 percent debt and 50 percent equity and the Company's proposed 10.5-percent ROE (Exhs. NG-ITP-1, at 9; NG-RRP-1, at 39; WP NG-RRP-7a (Rev. 4), WP NG-RRP-7b (Rev. 4), WP NG-RRP-7d (Rev. 4), DPU-NG 6-5). The amount of the rate-year rent expense is derived from two adjustments to test-year charges. During the test year, NGSC charged National Grid $36,462,051 in service company rents (Exhs. NG-RRP-1, at 38; NG-RRP-2 (Rev. 4), Sch. 17, at 4). National Grid made a normalizing adjustment of ($5,073,206) to restate the allocation of service company rents to the Company based on a true up of the return on and of capital calculations (Exhs. NG-RRP-1, at 38-39; NG-RRP-2 (Rev. 4), Sch. 17, at 4; DPU-NG 13-32). The Company then made a further adjustment to decrease the normalized test-year service company rents by ($5,828,333) to the proposed rate-year amount by calculating an average rate-year balance of service company rent expense, including the Company's requested ROE (Exhs. WP NG-RRP-7a (Rev. 4); WP NG-RRP-7b (Rev. 4); WP NG-RRP-7d (Rev. 4); DPU-NG 13-26; NG-RPP-2 (Rev. 4), Sch. 17, at 4).

The Department has reviewed the documentation and finds that the costs associated with NGSC IT investments are reasonable and should be included in the Company's cost of service in the form of a rent expense, with modifications to the Company's calculation. The Company calculated a return on IT investments using its proposed 10.5-percent ROE (Exh. DPU-NG 6-5 & Att.). The Department finds that the use of the petitioning company's approved ROE in calculating the return component of capital charges by an affiliated company[123] is appropriate and consistent with Department precedent. D.P.U. 17-05, at 165-166; D.P.U. 15-155, at 303-304. Thus, we apply the ROE of 9.60 percent approved in Section XIV.E., below.

In addition, the Company based its calculations on NGSC's capital structure of 50 percent debt and 50 percent equity (Exhs. NG-ITP-1, at 9; NG-RRP-1, at 39; WP NG-RRP-7a (Rev. 4), WP NG-RRP-7b (Rev. 4), WP NG-RRP-7d (Rev. 4), DPU-NG 6-5). The Department has found that where a petitioning company pays a return component on a facility owned by an affiliate, customers of the petitioning company may be forced to subsidize the operations of the affiliate. D.P.U. 17-05, at 220; D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 82-83. As such, the Department has used the return component to the weighted cost of capital applicable to the petitioning company. D.P.U. 17-05, at 220; D.P.U. 10-55, at 266-267; D.P.U. 08-27, at 82. Thus, we find it appropriate to use National Grid's capital structure in calculating the return component of capital charges by NGSC.[124] Accordingly, for the return component of NGSC rent expenses, the Department calculates the weighted average cost of capital ("WACC") using the ROE of

---

123 National Grid and NGSC qualify as affiliated companies under G.L. c. 164, § 85 and 220 CMR 12.02 (Exhs. AG 1-26; AG 1-98 (Supp.), Att. at 1). D.P.U. 09-39, at 245-246.

124 The Department acknowledges that in D.P.U. 15-155, at 303, we used NGSC's capital structure in calculating the return component of capital charges by NGSC. We find that in the instant case the capital structure of the affiliate was imputed and is not representative of decisions and investments made under the Department's jurisdiction (Exh. DPU-NG 6-5, Att.). Moreover, the Department is persuaded that it is appropriate to calculate the return component of capital charges using a petitioning company's ROE and capital structure.

9.60 percent approved in this Order and the Company's capital structure stated in this Order (see Section XIV.E., below). Use of the 9.60 percent ROE and the Company's approved capital structure produces an overall weighted cost of capital of 7.56 percent and a pre-tax WACC of 9.49 percent (see Exh. DPU-NG 6-5 & Att.). Application of the pre-tax WACC to NGSC's allocation of rent expense yields a rate-year service company rent expense of $25,709,215, consisting of $20,614,566 in existing information systems projects in service during the test year, $3,518,361 in post-test-year information systems projects, $1,564,523 in existing facilities in service during the test year, and $11,764 in post-test-year facilities (see Exhs. WP NG-RRP-7a (Rev. 4); WP NG-RRP-7b (Rev. 4); WP NG-RRP-7d (Rev. 4)). Accordingly, the Department increases the Company's proposed service company rent expense by $148,703.

c. Future Service Company Rent Petitions

Now, we turn to the Attorney General's recommendation that the Department require the Company to prepare and submit, on an annual basis, a long-term IT plan specific to the Massachusetts service territory (Attorney General Brief at 51, citing Exh. AG-GLB-Surrebuttal-1, at 17). The Attorney General states that such a plan would allow for a more meaningful review of the prudency of IT project implementation, allocation of costs, and alignment of individual projects with overall IT strategy (Attorney General Brief at 51-52, citing Exh. AG-GLB-Surrebuttal-1, at 17).

According to National Grid, it currently employs rigorous procedures in planning and implementing its IT investments (Exh. NG-ITP-Rebuttal-1, at 5). Specifically, IT business partners work closely with functional leadership and jurisdictional presidents on an annual basis to identify investments that will be required during the following three years to meet the needs of the business (Exh. NG-ITP-1, at 8). Further, IT investments are prioritized against overall expenditure targets through a project sanctioning process, and funding must be secured by the appropriate delegations of authority (Exhs. NG-ITP-1, at 8; AG 20-4). In addition, the Company states that National Grid plc published its first formal IT strategy in 2017, which is updated annually, and includes an investment plan to comply with regulations, secure against cyber threats, and enable its business (Exh. AG 30-1 & Att. 2). Nevertheless, National Grid states that if the Department elects to require an annual plan, the Company should be required provide the Department with the same type of reporting and information that Niagara Mohawk Power Corporation provides to the New York State Department of Public Service (Company Brief at 210).

The Department recognizes that IT functionality is becoming an increasingly important resource for the Company. For instance, NGSC describes IT as “a critical tool for energy utilities” and a “central enabler,” and describes the role of the IT organization as changing from being an order taker and service delivery organization to a key partner with the business in developing strategies to address the most pressing business needs (Exh. AG 30-1, Att. 2, at 12). In conjunction with the increasing importance of IT in business functions, the size and scope of IT investments also has become more significant, and this trend likely will continue.[125]

Based on these considerations, and after careful review of the arguments of the parties, the Department finds that, going forward, a more comprehensive review of the Company's IT investments and associated documentation substantiating the need for and prudency of specific IT investments, is warranted. We are not, however, persuaded that an annual review of the Company's IT investment plan is necessary and, therefore, we decline to accept the Attorney General's recommendation to require the Company to submit an annual long-term investment plan specific to the Massachusetts service territory.

The Department, however, finds that the current standard of review for lease expense (reasonableness) is no longer sufficient to satisfy the burden of proof necessary for IT-related investments.[126] Therefore, the Department no longer will use the "reasonableness" standard

---

[125] For example, the magnitude of IT investments has increased from less than $800,000 in the Company's 2009 base distribution rate case (D.P.U. 09-39, at 158-159) to over $29 million in the Company's 2015 base distribution rate case (D.P.U. 15-155, at 308), and represents a similarly large investment in the instant case (Exhs. NG-RRP-1, at 38-39; NG-RRP-2 (Rev. 4), Sch. 17, at 4; DPU-NG 13-32). NGSC projects a total capital expenditure outlook for IT investments across the National Grid USA system of nearly $350 million each year for the next three years (Exh. AG 30-1, Att. 2, at 18-19, 20-21).

[126] When facility leases have been entered into with affiliated companies, the Department relies on the affiliated transaction standard to evaluate these lease agreements. Agawam Springs Water Company, D.P.U. 13-163, at 29 (2014); D.P.U. 95-118, at 41-42. Specifically, the Department permits rate recovery of payments to affiliates where those payments are: (1) for activities that specifically benefit the regulated utility and that do not duplicate services already provided by the utility; (2) made at a competitive and reasonable price; and (3) allocated to the utility by a formula that is both cost effective in application and nondiscriminatory for those services specifically

when reviewing IT-related lease expense between affiliates. Further, the Department finds that because the underlying IT investments are capitalized on the books of an affiliate, the evaluation of these investments solely based on standards used for O&M expense is inappropriate and does not sufficiently protect ratepayer interests. Rather, in light of the recognition that increased scrutiny is warranted for IT investments, the Department modifies, effective with this Order, the criteria by which we evaluate the eligibility of IT-related service company rent expense for recovery through rates.

To facilitate a more comprehensive review of future IT-related investments for prudency and ratepayer benefits, the Department establishes the following criteria as the standards necessary for rents associated with an affiliate's capitalized IT investments to be included in rates. First, the investments underlying the rent expense must be in service and used and useful. D.P.U. 95-118, at 42. Second, the underlying investments must be prudently incurred. D.P.U. 95-118, at 42. Third, the underlying 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. 88-170, at 21; Housatonic Water Works Company, D.P.U. 86-93, at 18 (1987); see also D.P.U. 12-86, at 11, citing Public Utility Holding

---

rendered to the utility by the affiliate and for general services that may be allocated by the affiliate to all operating affiliates. D.P.U. 95-118, at 41, citing D.P.U. 92-101, at 42-46; D.P.U. 85-137, at 51-52. In addition, 220 CMR 12.04(3) provides that "an Affiliated Company may sell, lease, or otherwise transfer an asset to a Distribution Company, and may also provide services to a Distribution Company, provided that the price charged to the Distribution Company is no greater than the market value of the asset or service provided."

Company Act of 1935, P.L. No. 333 (1935), 49 Stat. 803, § 1 (1935); Report of the Special Commission on Control and Conduct of Public Utilities (1930 H. 1200, § 31).

In addition to the revised standard of review, the Department finds that it is critical for a petitioning company to provide complete and detailed IT-related investment documentation in a timely fashion. Therefore, the Department directs petitioning companies to submit, as part of their initial filings requesting new base distribution rates, 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. A petitioning company shall seasonably amend its initial filing to include documentation associated with post-test-year investments, if applicable. Further, 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. The Department notes that failure to provide complete and reviewable documentation in accordance with the above filing requirements may result in cost disallowance consistent with long-standing Department precedent.[127]

---

[127] 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. D.P.U. 95-40, at 7;

Finally, in addition to the revised review standard and the additional filing requirements, we have determined that it is appropriate to open an investigation to address the efficiencies of operations and productivity of National Grid's management and personnel (see Section XV., below). This investigation should aid the Department and the Attorney General in future proceedings concerning the Company's IT-related investments.

G. Depreciation

1. Introduction

During the test year, National Grid booked \$141,891,667 in depreciation expense (Exh. NG-RRP-2 (Rev. 4), Sch. 6, at 1). The Company derived an annualized depreciation expense of \$138,626,875 by applying currently authorized depreciation rates to the test-year-end depreciable plant balance, of which \$1,949,946 was assigned to transmission and \$132,235,343 was assigned to base distribution, the remainder, \$4,441,586, was assigned to general plant (Exh. NG-KAK-1, at 13). National Grid initially proposed to decrease its annualized test-year depreciation expense by \$2,484,835 to \$136,142,040 to recognize the application of new accrual rates to its pro forma plant in service (Exh. NG-KAK-1, at 13). The Company's initially proposed annualized expense would result in rate year depreciation expense of \$144,036,922, an increase of \$2,145,255 from the test year booked expense (Exh. NG-RRP-2, Sch. 6, at 1). During the course of the proceeding, the Company made adjustments to smart grid investment depreciable plant balances such that the final proposed

---

D.P.U. 93-60, at 26; D.P.U. 92-210, at 24; see also 376 Mass. 294, 304; 352 Mass. 18, 24. This same caution applies to service company allocated IT investment costs.

rate year depreciation expense equaled $141,487,121, a decrease of $404,546 from the test year booked expense (Exh. NG-RRP-2 (Rev. 4), Sch. 6, at 1). National Grid based its proposed accrual rates on a 2018 depreciation study that recommended an overall accrual rate of 3.05 percent, representing a decrease from the Company's current overall accrual rate of 3.11 percent (Exh. NG-KAK-1, at 13).

The Company's 2018 depreciation study was based on plant data for the year ending December 31, 2017, and was developed by coding and appending annual plant, net salvage, and depreciation reserve transactions to the database developed to support the 2015 technical update (Exh. NG-KAK-1, at 9). The Company states that the data used to conduct the 2015 technical update was assembled by appending 2009 through 2014 plant and reserve activity to the database used in conducting the 2009 depreciation study (Exh. NG-KAK-1, at 9). As a check on the accuracy of the data, the Company compared the additions, retirements, transfers, adjustments, and ending balances derived for each activity year to the Company's adjusted plant records (Exh. NG-KAK-1, at 9-10).

The Company's 2018 depreciation study makes use of the remaining life method, straight-line depreciation method, and vintage group procedure (Exh. NG-KAK-1, at 11-12). The Company calculated the remaining life of assets by using observed retirement ratios that were fitted by a weighted least-squares procedure to the Iowa-Curve[128] family to develop a

---

128 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. Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/Canal Electric Company, D.T.E. 06-40, at 66-67 n.44 (2006).

mathematical description of the dispersion characteristics of the data, resulting in an average service life for each account (Exh. NG-KAK-1, at 10).

Prior to a 1996 study, National Grid's depreciation rates did not include a net salvage component; a net salvage rate of zero percent was assumed for all plant accounts (Exh. NG-KAK-3, at 12). While net salvage was considered in the 1996 study, accrual rates and reserves were developed at the function level for net salvage and by primary accounts for investment accruals (Exh. NG-KAK-3, at 12). Upon implementation, National Grid combined the function net salvage rates within the investment rate for each primary account and continued to record depreciation accruals and realized net salvage in function level reserves (Exh. NG-KAK-3, at 12). In 2004, the Company migrated to a plant accounting system and function reserves were disaggregated in the conversion process to initialize reserves by primary account (Exh. NG-KAK-3, at 12). Accordingly, National Grid states that the earliest activity year in which realized net salvage is identifiable by primary account is 2004 (Exh. NG-KAK-3, at 12). The Company states that the limited history, as well as significant variability in realized net salvage as a percent of retirements, necessitated an examination of how net salvage is charged to work orders and a back-casting of current practices to prior activity years (Exh. NG-KAK-3, at 12).

To determine the net salvage values, the Company performed a five-year moving average analysis of the ratio of realized salvage and removal cost to the associated

---

These curves are widely accepted in determining average life frequencies for utility plant.

retirements (Exh. NG-KAK-1, at 6, 10). The Company combined this analysis, opinions from Company personnel, and judgment to develop estimates of future net salvage (Exh. NG-KAK-1, at 6, 11). National Grid calculated average net salvage rates using direct-dollar weighting of historical retirements with the historical net salvage rate, and future retirements with the estimated future net salvage rate (Exh. NG-KAK-1, at 11).

Additionally, as part of the 2018 depreciation study, National Grid examined the depreciation reserves associated with each of its plant accounts (Exh. NG-KAK-1, at 11). While differences between the theoretical depreciation reserve and the recorded reserve will arise in the normal course of adjusting depreciation accrual rates, the Company considers it appropriate to periodically redistribute the recorded reserves among the primary accounts to correct over- or under-accruals for these accounts (Exh. NG-KAK-1, at 7). The Company analyzed the recorded depreciation reserves against the redistributed reserves as of December 31, 2017, and it determined that while the recorded reserve was $1,775,009,707, the computed reserve was $1,602,696,746, thus creating a reserve excess of $172,312,961 (Exh. NG-KAK-1, at 11). Based on the results of the 2018 depreciation study, the Company proposed to redistribute its recorded reserves among its various plant accounts to reduce offsetting imbalances and to establish reserves for subaccounts created subsequent to the adoption of current depreciation rates (Exh. NG-KAK-3, at 14).[129]

---

[129] The Company states that this reallocation has no effect on its total recorded depreciation reserve (Exh. NG-KAK-3, at 20).

2. Positions of the Parties

a. Attorney General

i. Introduction

The Attorney General recommends that the Department reject National Grid's redistribution of its depreciation reserves (Attorney General Brief at 58). The Attorney General also maintains that the Department should reject the Company's proposed service lives for eight of its transmission and distribution accounts (Attorney General Brief at 56). Additionally, the Attorney General asserts that, contrary to the Company's assertions, a site visit is not necessary and suggests that the Company's depreciation consultant did not conduct a site visit (Attorney General Reply Brief at 23).

ii. Reserve Redistribution

Regarding National Grid's manual rebalancing, or redistribution, of its depreciation reserves, the Attorney General recommends that the Department reject the Company's proposal (Attorney General Brief at 58; Attorney General Reply Brief at 23). The Attorney General contends that the proposed redistribution does not conform to industry standards or authoritative industry treatises (Attorney General Brief at 57, citing Exh. AG-DJG-1, at 13; Attorney General Reply Brief at 23-24). According to the Attorney General, the authoritative depreciation texts in the industry hold that it is unnecessary to redistribute the reserve when a utility calculates depreciation rates using the remaining life technique (Attorney General Brief at 58, citing Exh. AG-DJG-Surrebuttal-1, at 2; Attorney General Reply Brief at 23). The Attorney General adds that the Company could not produce any textbook or manual that employs the proposed method of "periodic redistribution" (Attorney General Brief at 60, citing Tr. 8, at 436). The Attorney General, therefore, argues that the Company did not use a reliable and accepted method when calculating its depreciation rates and, as such, the Department should not accept National Grid's proposed reserve redistribution (Attorney General Brief at 60; Attorney General Reply Brief at 23-24).

iii. Accrual Rates

The Attorney General maintains that National Grid failed to meet its burden to demonstrate that its proposed depreciation accrual rates are not excessive for eight of its accounts (Attorney General Brief at 56, citing Lindheimer v. Illinois Bell Telephone Co., 292 U.S. 151, 169 (1934); Attorney General Reply Brief at 21). Specifically, the Attorney General argues that National Grid's proposed service lives for eight of its transmission and distribution accounts are unreasonably short given the Company's own recorded retirement experience (Attorney General Brief at 60, citing Exhs. AG-DKG-1, at 7, 14, 19; AG-DJG-Surrebuttal-1, at 4-6). The Attorney General recommends that the Department reject the Company's proposed rates and accept the Attorney General's proposed service lives and resulting accrual rates for those eight accounts (Attorney General Brief at 61; Attorney General Reply Brief at 21).

According to the Attorney General, her proposed rates are fair, reasonable, and derived using a reliable and accepted method (Attorney General Brief at 61, citing Exh. AG-DJG-1, Apps. A, B, and C). She explains that her rates are derived using the retirement rate method, which fits survivor curves to Iowa curves (Attorney General Brief at 61-62, citing Exh. AG-DJG-1, at 15-16, App. C). The Attorney General represents that, although she had access to notes and records associated with the Company's witness's site visit and discussions with Company personnel, she mainly relied on historical data to fit the survivor curves to Iowa curves because there was no convincing evidence to suggest that future average service lives would be materially different from historic experience (Attorney General Brief at 62, citing Exhs. AG 2-4; AG 2-5; AG 2-6; AG 2-7).

The Attorney General contends that both visual and mathematical curve fitting techniques confirm that her proposed curves fit better than National Grid's proposed curves for the eight accounts in question (Attorney General Brief at 62, citing Exh. AG-DJG-1, at 21-22). The Attorney General adds that the Company's methods are clearly not superior to hers because the rates proposed and approved in D.P.U. 09-39, using the same expert as the instant case, have actually made the large reserve surplus even larger, rather than smaller, as correct depreciation accrual rates would (Attorney General Reply Brief at 22).[130] According to the Attorney General, the Company's depreciation expense should be decreased by $11,857,699 to remedy the above issues (Attorney General Brief at 66).

b. Company

i. Reserve Redistribution

National Grid first declares that the Department has previously approved the redistribution of reserves (Company Brief at 320, citing Exh. NG-KAK-1, at 11; Tr. 3,

130 The Attorney General contends that the difference between the Company's recorded and computed depreciation reserve has grown to $172,312,961, from $135,974,350 in D.P.U. 09-39 (Attorney General Reply Brief at 22-23).

at 422-423; Company Reply Brief at 115-116). National Grid elaborates that the Department has previously approved the Company's depreciation rates, which were based on a rebalancing of reserves, in D.P.U. 09-39 and D.P.U. 15-155 (Company Brief at 320, citing Exh. DPU-NG 34-2; RR-DPU-8, Att.). The Company argues that the Attorney General's contentions regarding the validity of the rebalancing are misleading and that her own approach to the reserve is flawed (Company Brief at 326; Company Reply Brief at 115-116). In particular, the Company refutes the Attorney General's claim that no other depreciation analysts follow this method (Company Brief at 326, citing RR-DPU-8, Att.; Company Reply Brief at 115, citing RR-DPU-8). National Grid also asserts that none of the authoritative texts, including the National Association of Regulatory Utility Commissioners Manual: Public Utility Depreciation Practices, published August 1996 ("NARUC Depreciation Manual") and Depreciation Systems, Frank K. Wolf and W. Chester Fitch, (1st ed.), Iowa State University Press, Ames (1994) ("Depreciation Systems"), indicate that rebalancing is inappropriate when using the remaining-life technique (Company Brief at 327, citing Exh. NG-KAK-Rebuttal-1, at 8; Company Reply Brief at 115).[131] The Company posits that the rebalancing was not only appropriate, but also necessary (Company Brief at 327). National Grid elaborates that the Company needed to redistribute four reserves among eleven

[131] Expert witnesses presenting testimony before public utility commissions regularly rely on these texts. In addition, FERC and state regulatory commissions, including the Department, cite to these texts as authoritative. Pursuant to 220 CMR 1.10(2), the Department may take official notice of general, technical, or scientific facts within its specialized knowledge. The Department takes official notice of (1) NARUC Depreciation Manual and (2) Depreciation Systems.

accounts and redistribute an unallocated reserve of $6.8 million associated with two accounts (Company Brief at 327). National Grid alleges that the Attorney General's attempt at rebalancing erroneously produced negative depreciation rates for six accounts because she did not consider the age, remaining life, or average service life of the respective accounts (Company Brief at 327, citing Exh. NG-KAK-Rebuttal-1, at 10; Company Reply Brief at 115-116, citing Exh. NG-KAK-Rebuttal-1, at 9-10, 12; Tr. 11, at 1490-1491). As such, the Company requests that the Department accept the Company's, rather than the Attorney General's, method of redistributing the booked reserves (Company Brief at 327; Company Reply Brief at 116).

ii. Accrual Rates

National Grid contends that its proposed depreciation accrual rates are appropriate and that the same methodology has been approved by the Department in previous base distribution rate cases (Company Brief at 321). The Company additionally alleges that the Attorney General's analysis is flawed for several reasons and must be rejected (Company Brief at 321; Company Reply Brief at 111).

National Grid asserts that the Attorney General recommends longer life curves for six distribution plant accounts and two transmission plant accounts, claiming that her proposed curves have a better fit visually and mathematically (Company Brief at 321, citing Attorney General Brief at 63-65). The Company contends that the Attorney General's "mathematical fitting" technique is nothing more than a computerized version of visual fitting and, as such, she has only relied upon visual fitting to choose the correct curve (Company

Brief at 322; Company Reply Brief at 111-112). The Company asserts that its life analysis is based on a superior method that includes hazard rates and polynomials (Company Brief at 322). Moreover, according to National Grid, authoritative depreciation texts recognize the superiority of hazard functions and polynomials (Company Brief at 323, citing Exh. NG-1; Company Reply Brief at 112-113, citing Exh. NG-1).

With respect to the Attorney General's claim that the Company's method of determining accrual rates is flawed due to the increase in the difference between the recorded and computed reserves (i.e., the reserve imbalance), National Grid responds that such an argument is flawed, as any reserve imbalance should not be compared at different points in time using nominal amounts (Company Reply Brief at 113). The Company contends that the proper comparison of the reserve imbalances at two different points in time must look at the imbalance as it relates to the recorded reserve, in which case the percentage has actually decreased from 10.89 percent in D.P.U 09-39 to 9.7 percent in the instant proceeding (Company Reply Brief at 113-114).

Additionally, National Grid argues that the Attorney General's life curve analysis is deficient because she did not perform a site visit or discuss with management reasons explaining the retirement of property (Company Brief at 324, citing Exh. NG-KAK-Rebuttal-1, at 19-20). The Company maintains that the Attorney General's claim that the Company's witness did not tour any of the Company's facilities is false, and that observations during the site visit, along with information obtained from Company personnel informed the Company's proposed average service lives (Company Reply Brief at 114).

The Company continues that several of the Attorney General's life estimations are flawed because they ignore important statistical and judgment-based considerations (Company Brief at 324). According to the Company, the Attorney General does not take into account the aging population of power transformers or reports by Company engineers for Account 362 (Company Brief at 324; Company Reply Brief at 114). The Company argues that, for Account 355 and Account 364, the Attorney General's recommendations are not supported by the polynomial analysis (Company Brief at 325). For Account 356, National Grid posits that the Attorney General does not consider recent retirement trends indicating shorter average service lives (Company Brief at 325). The Company maintains that its analysis of Account 365 reflects the use of polynomial analysis and hazard rates, while the Attorney General's analysis reflects only visual curve fitting (Company Brief at 325). For Account 366, National Grid asserts that the Attorney General's analysis provides little insight into expectations specific to the Company because it relies on averages of other utilities (Company Brief at 325).[132] Further, the Company maintains that its recommendation

---

[132] Pursuant to the FERC "Uniform System of Accounts Prescribed for Public Utilities and Licenses Subject to the Provisions of the Federal Power Act" at 18 CFR Part 101 ("Uniform System of Accounts for Electric Companies"), the accounts under discussion are the following: Account 362 Storage Equipment; Account 355 Poles and Fixtures; Account 364 Poles, Towers, and Fixtures; Account; Account 365 Overhead Conductors and Devices; Account 366 Underground Conduit; Account 367.10 Underground Conductors and Devices; and Account 368.20 Line Transformers – Bare Cost. See also 220 CMR 51.01(1) (Department's adoption of FERC Uniform System of Accounts for Electric Companies).

properly takes into account a significant discontinuity at age 30 that the Attorney General ignores (Company Brief at 325). Finally, National Grid contends that the Company's analysis reveals that average service lives are getting shorter, while the Attorney General's visual curve fitting of one band cannot and does not reveal this trend (Company Brief at 325, citing Exh. NG-KAK-Rebuttal-1, at 23-31).

c. Analysis and Findings

i. 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. D.T.E. 98-51, at 75; D.P.U. 96-50 (Phase I) at 104; Milford Water Company, D.P.U. 84-135, at 23 (1985); D.P.U. 1350, at 97. Depreciation studies rely not only on statistical analysis but also on the judgment and expertise of the preparer. The Department has held that when a company reaches a conclusion about a depreciation study that is at variance with that witness's engineering and statistical analysis, the Department will not accept such a conclusion absent sufficient justification on the record for such a departure. D.P.U. 92-250, at 64; The Berkshire Gas Company, D.P.U. 905, at 13-15 (1982); Massachusetts Electric Company, D.P.U. 200, at 21 (1980).

The Department recognizes that the determination of depreciation accrual rates requires both statistical analysis and the application of the preparer's judgment and expertise. D.T.E. 02-24/25, at 132; D.P.U. 92-250, at 64. Because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable.[133] 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.

ii. Reserve Redistribution

As an initial matter, the Department finds it necessary to elucidate the distinction between theoretical reserves (also commonly referred to as calculated accumulated depreciation, reserve requirement, or computed reserves) and recorded reserves (also referred

133 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.

to as book reserves). NARUC Depreciation Manual at 325. Recorded reserves represent the net amount of depreciation expense actually charged to previous periods of operations, while theoretical reserves are the estimated theoretically correct book depreciation reserves based upon either past and/or future service life and net salvage considerations (Exh. NG-KAK-3, at 13). NARUC Depreciation Manual at 188, 325. There are two acceptable approaches to develop theoretical reserves:[134] (1) a retrospective approach, which attempts to reconstruct past accruals and retirements to determine what the accumulated provision for depreciation would have been given the current depreciation parameters; and (2) a prospective approach, which estimates the sum of the future additions to, and subtractions from, the accumulated provision for depreciation. Depreciation Systems at 84; NARUC Depreciation Manual at 189-193. A reserve imbalance is calculated as the difference between the recorded reserve and the estimated theoretical reserve. NARUC Depreciation Manual at 188.

The Attorney General refers to authoritative texts on depreciation to support her argument that when the remaining life technique is used to calculate depreciation rates, it is not appropriate to reallocate a theoretical reserve (Attorney General Reply Brief at 23-24). The Attorney General's understanding of both the Company's proposal and the authoritative texts, however, is misguided. In discussing potential reserve imbalances, both the NARUC Depreciation Manual and Depreciation Systems acknowledge that when using the remaining

---

[134] The Department will expound the two approaches, as the Attorney General's depreciation expert appears to prefer a retrospective approach, while the Company's depreciation expert prefers a prospective approach (Exhs. NG-KAK-Rebuttal-1, at 9; AG-DJG-1, at 12).

life technique, any variation between the theoretical reserve and the recorded reserve (i.e., the reserve imbalance) is effectively amortized over the remaining life of the plant in service and any necessary adjustment is included in the calculation of the accrual rate. Depreciation Systems at 87, 91; NARUC Depreciation Manual at 65. Essentially, the use of the remaining life technique accounts for any reserve imbalance, and, therefore, any existing imbalance should not be redistributed. In the instant proceeding, the Company has neither proposed to redistribute the reserve imbalance nor the theoretical reserve as the Attorney General contends (Exh. AG-DJG-Surrebuttal-1, at 2). In fact, the total reserve for depreciation remains unchanged under the Company's proposal (Exh. NG-KAK-3, at 20-21). Instead, the Company has proposed a redistribution of its recorded reserves (Exh. NG-KAK-3, at 14). National Grid argues that the proposed redistribution is necessary due to historical changes in accruing net salvage, as well as to correct for accounts that did not historically have reserves properly recorded (Exhs. NG-KAK-1, at 6-7; NG-KAK-3, at 14; DPU-NG 34-1). While the authoritative texts are clear that redistributions of any imbalance or the theoretical reserve are not appropriate when using the remaining life technique, they do not proscribe the redistribution of existing recorded reserves. In fact, the NARUC Depreciation Manual at 188 states that, "[t]heoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts. Such allocation is done when either the reserve has not been accumulated in sufficient detail or cannot be determined from utility records."

The Department has reviewed the Company's proposed redistribution of recorded reserves, and finds that the exigent circumstances underlying the redistribution are legitimate and that the method by which the reserve was redistributed is reasonable (Exhs. NG-KAK-1, at 6-7; NG-KAK-3, at 14, 20-21; DPU-NG 34-1). The Department, therefore, accepts the Company's proposed reserve redistribution. The Department, however, does not take accounting adjustments lightly, and notifies all companies that any future proposals to redistribute recorded reserves as part of a depreciation study by a utility will require a similar demonstration that such rebalancing is necessary and appropriate.

iii. Accrual Rates

(A) Introduction

Both the Company and the Attorney General claim that their own proposed accrual rates, and the methods by which each party derived them, are superior. The Department reminds both parties that, according to the NARUC Depreciation Manual at 22, "[t]he estimation of depreciation parameters is not, of course, a scientifically exact process, since it involves a large element of informed judgment regarding future developments." While depreciation accrual rates certainly should not be arbitrary, they are calculated figures, and there exists a zone of reasonableness within which the underlying parameters may be expected to lie. NARUC Depreciation Manual at 23; Depreciation Systems at preface VIII-IX. Further, the Department has previously noted that because depreciation studies rely by their nature on examining historic performance to assess future events, a degree of subjectivity is inevitable. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 214;

D.P.U. 15-155, at 199; D.P.U. 17-05, at 200. Moreover, the Department does not consider any one factor in isolation when reviewing the appropriateness of proposed depreciation accrual rates; information gleaned from site visits, information regarding underlying assets in an account, statistical analyses (including the use of polynomials and hazard rates), mathematical and visual curve fitting, and expert judgement are examples of some of the myriad factors the Department finds relevant in evaluating proposed depreciation accrual rates. D.P.U. 15-155-B at 15-19.

Based on our comprehensive review, the Department finds that National Grid has properly interpreted the results of its depreciation study and the underlying statistical analyses, and used appropriate judgment in determining the depreciation accrual rates for those accounts that were not contested by the parties (Exhs. DPU-NG KAK-3; NG-KAK-4). Therefore, the Department accepts the accrual rates proposed by the Company for the uncontested accounts. Our discussion of the proposed accrual rates for the contested accounts follows.

(B) Account 355

The current accrual rate for Account 355 (Poles and Fixtures) is 3.04 percent (Exh. NG-KAK-3, at 17). National Grid proposes to replace the current average service life of 40 and S2 curve with a 45-year average service life and an S1 curve, producing an accrual rate of 3.73 percent (Exhs. NG-KAK-3, at 17; NG-KAK-4, at 43). The Attorney General, in contrast, proposes an average service life of 57, an R2 curve, and an accrual rate of 2.76 percent (Exh. AG-DJG-1, at 7, 19-20).

Account 355 includes the installed cost of transmission line poles, wood, steel, concrete, or other material, together with appurtenant fixtures used for supporting overhead transmission (Exh. NG-KAK-4, at 43). The Company articulates that with respect to poles, the Company mostly installs Douglas Fir and Southern Yellow Pine, which have a design life in the 40- to 50-year range for non-remedial poles, and an expected service life of 70 to 80 years for remediated poles (Exh. NG-KAK-4, at 44). National Grid explains that not only are wooden poles treated to protect against decay and insect attack, they are also treated with a steel "C-truss" or fiberglass wrap to provide additional support after minimal deterioration is detected through periodic inspections (Exh. NG-KAK-4, at 43). Such existing remediation efforts suggest that an appropriate average service life for this account lies somewhere between the 40- to 50-year and 70- to 80-year ranges.

The Company's rolling, shrinking, and progressing band life analysis for Account 355 do not adequately support the Company's proposal, as the high conformance indices and amount of censoring suggest the statistical analysis alone may not be relied upon (Exh. NG-KAK-4, at 54-57). To arrive at her proposed accrual rate, the Attorney General relied upon visual curve fitting, as well as mathematical curve fitting techniques (Exh. AG-DJG-1, at 20-21). While National Grid argues that the Attorney General's visual and mathematical curve fitting are essentially identical procedures, the Company is mistaken. Both the NARUC Depreciation Manual and Depreciation Systems distinguish between visual and mathematical curve fitting, noting that mathematical curve fitting involves a calculation of the sum of squared differences ("SSD"), where the best fitting curve is that which exhibits the lowest SSD. NARUC Depreciation Manual at 124-125; Depreciation Systems at 47. Furthermore, while National Grid attempts to dismiss visual fitting as inferior to statistical analyses, authoritative depreciation texts discuss the merits of each method, and state that the results of both statistical and mathematical curve fitting should serve as guides that should be checked visually, with final determinations based on the judgment of the depreciation analyst. NARUC Depreciation Manual at 126, 247; Depreciation Systems at 47-48.[135]

The Attorney General's average service life and curve selection produce an SSD of 0.1848, compared to her use of the Company's average service life and curve selection, which demonstrate an SSD of 1.6844 (Exhs. AG-DJG-1, at 21; AG-DJG-7). Additionally, a visual inspection of both proposals compared to the actual retirement data for Account 355 indicates the Attorney General's proposed curve-life combination is a superior fit (Exhs. AG-DJG-1, at 20; NG-KAK-4, at 60). Based on the results of the statistical analysis, the mathematical and visual curve fitting, as well as the composition and treatment of the assets in Account 355, the Department finds the Attorney General's proposal of a 57 average service life R2 curve to be reasonable.

While the Department accepts the Attorney General's proposed average service life and curve selection, her proposed accrual rate of 2.76 percent cannot be adopted. The calculation of accrual rates depends, in part, on the reserve ratio for each account, which is

---

135 The NARUC Depreciation Manual at 126, 153, notes that while mathematical techniques may in some instances yield better results, it also cautions analysts against relying solely on mathematical solutions.

the ratio of recorded reserves to plant investment (Exh. NG-KAK-3, at 16).[136] Because the Department has approved the Company's proposed redistribution of the recorded reserve in Section VIII.G.c.ii., above, a new accrual rate must be calculated that incorporates both the Attorney General's parameters and the Company's redistributed reserves. Based on the Attorney General's average service life and curve selection, Account 355 exhibits a composite average remaining life of 44.84 years (Exh. AG-DJG-16, at 3). Based on National Grid's reserve redistribution, Account 355 has a reserve ratio of 25.63 percent (Exh. NG-KAK-3, at 20, 23). With a proposed future salvage of negative 50 percent for Account 355 and the factors above, the Department calculates an updated accrual rate of 2.77 percent,[137] which when applied to the Account 355 investment of $31,928,978, results in an annual accrual of $885,595 (Exhs. NG-KAK-3, at 16, 26; NG-KAK-4, at 43). Compared to the Company's proposed accrual of $1,190,951, the Department's calculated annual accrual represents a decrease to depreciation expense of $305,356.

(C) Account 356

The existing accrual rate for Account 356 (Overhead Conductors and Devices) is 2.49 percent (Exh. NG-KAK-3, at 17). National Grid proposes to replace the current average service life of 50 and S1.5 curve with a 55-year average service life and an R2 curve, and an accrual rate of 2.99 percent (Exhs. NG-KAK-3, at 17, 26; NG-KAK-4, at 63).

---

136 The formula for calculating an accrual rate is: (1.0 – Reserve Ratio – Future Net Salvage Rate) / Remaining Life (Exh. NG-KAK-3, at 16).

137 $0.0277 = (1.0 - 0.2563 - (-0.50)) / 44.84$

The Attorney General, in contrast, proposes an average service life of 49, an S0 curve, and an accrual rate of 2.63 percent (Exh. AG-DJG-1, at 7, 23).

Account 356 includes the installed cost of overhead conductors and devices used for transmission purposes (Exh. NG-KAK-4, at 63). The Company observes that assets in this account have experienced accelerated deterioration, potentially due to atmospheric conditions and salt spray, in addition to the regular forces of retirement (Exh. NG-KAK-4, at 63).

The rolling, shrinking, and progressing band analysis for this account suggests a broad range of potential average service lives, and many of the results exhibit a combination of high censoring and conformance indices (Exh. NG-KAK-4, at 74-77). Taking the limits of the statistical analysis in consideration, the Department notes that the most recent set of rolling bands, as well as many of the shrinking bands indicate a potential range of average service lives between 50 years and 60 years, with the shrinking band analysis demonstrating a slight trend of decreasing average service lives (Exh. NG-KAK-4, at 74-76). Turning to the visual curve fitting proffered by the Attorney General, it is unclear from a mere visual inspection which proposed curve is a better fit given the shape of the data points reflecting the actual retirement history (Exh. AG-DJG-1, at 23). The mathematical curve fitting conducted by the Attorney General indicates that the Company's proposal results in an SSD of 0.5172 while her proposal results in an SSD of 0.1250 (Exhs. AG-DJG-1, at 24; AG-DJG-8). While the results of the mathematical curve fitting denote a marginally better fit for the Attorney General's proposed curve and average service life, the Department finds that the combination of the band analyses, the recent increase in retirements for this account, and the hastened deterioration of assets are more supportive of the Company's proposal. Accordingly, the Department approves National Grid's proposed accrual rate of 2.99 percent for Account 356.

(D) Account 362

The current accrual rate for Account 362 (Station Equipment) is 2.04 percent (Exh. NG-KAK-3, at 17). National Grid proposes to replace the current average service life of 65 and L0.5 curve with a 45-year average service life and an L1.5 curve, and an accrual rate of 2.67 percent (Exhs. NG-KAK-3, at 17, 26; NG-KAK-4, at 140). The Attorney General, in contrast, proposes an average service life of 49, an S0 curve, and an accrual rate of 2.74 percent (Exh. AG-DJG-1, at 7, 25).

Account 362 includes the installed cost of station equipment used for the purpose of changing the characteristics of electricity in connection with its distribution (Exh. NG-KAK-4, at 140). The Company notes that advances in electronic technology in the form of microprocessor-based relays tend to induce obsolescence in newer equipment sooner than in older electro-mechanical equipment (Exh. NG-KAK-4, at 140). National Grid also explains that while the first generation of microprocessor-based relays have begun to be retired recently due to heat induced failures, newer relays are now housed in heating, ventilation, and air conditioning environments (Exh. NG-KAK-4, at 140). Additionally, the Company indicates there have been significant levels of retirement activity associated with indoor substations that it expects to continue (Exh. NG-KAK-4, at 141).

The Company's rolling band analysis provides a large range of average service lives that correspond to low conformance indices and low levels of censoring, and an examination of the shrinking band analysis, which is often useful for identifying trends over time, indicates that the average service lives are decreasing (Exh. NG-KAK-4, at 153-155). Compared to the existing average service life of 65, both the Attorney General and Company's recommendations accurately reflect this trend. Looking at the largest bands in both the shrinking and progressive band life analysis indicate average service lives of around 50 years, with no censoring and low conformance indices (Exh. NG-KAK-4, at 155-156). Turning to the mathematical fitting conducted by the Attorney General, her proposed average service life and curve has a lower SSD of 0.0251 compared to the Company's proposed average service life and curve, which has an SSD of 0.5137 (Exhs. AG-DJG-1, at 26; AG-DJG-9). Regarding the visual curve fitting, the Attorney General's proposed curve also affords a superior fit to the historical data than the curve proposed by the Company (Exh. AG-DJG-1, at 25). Based on a combination of the results of the statistical analyses, mathematical and visual curve fitting, and the treatment of assets in this account (notably, the newer practice of housing of relays in heating, ventilation, and air conditioning environments to prevent early retirements), the Department finds that the Attorney General's recommended 49 year average service life and S0 curve for Account 362 are reasonable and more appropriate than the Company's proposal.

While the Department accepts the Attorney General's proposed average service life and curve selection, her proposed accrual rate of 2.74 percent is not appropriate. Consistent with the analysis in Section VIII.G.c.ii., above, the Department will recalculate the accrual rate for Account 362 using the Attorney General's parameters and the Company's redistributed recorded reserves. Based on the Attorney General's average service life and curve selection, Account 362 exhibits a composite average remaining life of 39.66 years (Exh. AG-DJG-16, at 10). Based on National Grid's reserve redistribution, Account 362 has a reserve ratio of 30.37 percent (Exh. NG-KAK-3, at 20, 22). With a proposed future salvage of negative 25 percent for Account 362 and the factors above, the Department calculates an updated accrual rate of 2.39 percent,[138] which when applied to the Account 362 investment of $633,746,315, results in an annual accrual of $15,121,385 (Exhs. NG-KAK-3, at 16, 26; NG-KAK-4, at 43; NG-RRP-2 (Rev. 4), Sch. 6, at 1). Compared to the Company's proposed accrual of $16,921,027, the Department's annual accrual represents a decrease to depreciation expense of $1,799,642.

(E) Account 364

The current accrual rate for Account 364 (Poles, Towers, and Fixtures) is 3.41 percent (Exh. NG-KAK-3, at 17). National Grid proposes to replace the current average service life of 40 and S2 curve with a 45-year average service life and an S1.5 curve, and an accrual rate of 3.15 percent (Exhs. NG-KAK-3, at 17, 26; NG-KAK-4, at 162). The Attorney General, in contrast, proposes an average service life of 50, an L2 curve, and an accrual rate of 2.92 percent (Exh. AG-DJG-1, at 7, 27).

---

[138] $0.0239 = (1.0 - 0.3037 - (-0.25)) / 39.66$

Account 364 includes the installed cost of poles, towers, and related fixtures used for supporting overhead distribution conductors and service wires (Exh. NG-KAK-4, at 162). Compared with the Company's transmission poles, which receive routine aerial inspections biannually and regular ground and third-party inspections, the assets in Account 364 only receive visual inspections on a five-year rolling basis (Exh. NG-KAK-4, at 162).

The Company's rolling, shrinking, and progressing band analyses demonstrate low conformance indices for many of the examined bands, but suffer from high censoring, resulting in no clear average service life recommendation for this account based on the statistical analyses alone (Exh. NG-KAK-4, at 170-172). The age distribution of the assets in Account 364, however, indicates that no particular vintage has a realized life of over 45 years (Exh. NG-KAK-4, at 166-167). Regarding the mathematical curve fitting presented by the Attorney General, both her and the Company's proposal demonstrate very low SSDs of 0.0349 and 0.0677, respectively, with the Attorney General's exhibiting a marginally better fit (Exhs. AG-DJG-1, at 28; AG-DJG-10). Turning to the visual curve fitting, both curves represent an improvement from the current average service life and curve combination, and while they both approximate the actual data points of historic retirements closely, the Attorney General's curve appears to slightly overstate the percent of assets surviving compared to the Company's recorded history (Exhs. NG-KAK-4, at 175; AG-DJG-1, at 27). Based on the totality of the facts and the foregoing analysis, the Department finds that the Company's proposed average service life and curve to be reasonable, and that the nominal difference in mathematical fit alone does not persuade the

Department to adopt the Attorney General's recommendation. Accordingly, the Department approves the Company's proposed accrual rate of 3.15 percent for Account 364.

(F) Account 365

The current accrual rate for Account 365 (Overhead Conductors and Devices) is 3.19 percent (Exh. NG-KAK-3, at 17). National Grid proposes to replace the current average service life of 40 and L1 curve with a 45-year average service life and an SC curve, and an accrual rate of 3.17 percent (Exhs. NG-KAK-3, at 17; NG-KAK-4, at 178). The Attorney General, in contrast, proposes an average service life of 48, an O1 curve, and an accrual rate of 2.75 percent (Exh. AG-DJG-1, at 7, 29). Account 365 includes the cost of installed overhead conductors and devices used for distribution purposes (Exh. NG-KAK-4, at 178).

National Grid's rolling, shrinking, and progressing band analyses, while displaying low conformance indices, have high censoring and demonstrate a range of average service lives so wide as to render the results of little value in determining the proper curve life combination (Exh. NG-KAK-4, at 178, 186-188). While the band analyses exhibit indeterminacy, the age distribution analysis for the account exhibits only one vintage of assets in Account 365 with a realized life greater than 45, suggesting that the average service life chosen by the Company may be more apt (Exh. NG-KAK-4, at 183). Regarding the mathematical fitting presented by the Attorney General, her proposal presents an SSD of 0.0363, compared to an SSD of 0.0556 associated with National Grid's proposed curve and average service life (Exhs. AG-DJG-1, at 30; AG-DJG-11). While the Attorney General concedes that both her and the Company's proposals provide relatively close fits to the observed data, and that both are within a range of reasonableness for this account, the Attorney General argues that the Department should go with the curve that exhibits a better mathematical fit (Exh. AG-DJG-1, at 29). A close visual inspection of both curves confirms that both proposals are reasonable, however, the curve proposed by the Attorney General appears to overstate the percentage of assets surviving when compared to the observed data in more instances, and by a larger degree, than the Company's curve (Exh. AG-DJG-1, at 29). Based on the facts and preceding analyses, the Department finds that the Company's proposed average service life and curve for Account 365 are reasonable and provide a more gradual shift from the existing average service life of 40 for this account. Accordingly, the Department approves the Company's proposed accrual rate of 3.17 percent.

(G) Account 366

The current accrual rate for Account 366 (Underground Conduit) is 2.56 percent (Exh. NG-KAK-3, at 17). National Grid proposes to keep the existing S4 curve and average service life of 50 for this account and adjusts the net salvage from negative 35 percent to negative 20 percent (Exh. NG-KAK-4, at 194). The resulting accrual rate proposed by the Company is 2.21 percent (Exh. NG-KAK-3, at 17). The Attorney General, in contrast, proposes an average service life of 55, an R4 curve, and an accrual rate of 1.73 percent (Exh. AG-DJG-1, at 7, 31).

Account 366 includes the installed cost of underground conduits and tunnels used for housing distribution cables or wires (Exh. NG-KAK-4, at 194). The major forces of retirement for assets in this account are rebuilding and excavation, as they are typically installed in congested city centers (Exh. NG-KAK-4, at 194).

Due to an insufficient retirement history over the study period, the statistical analyses for Account 366 are unreliable and indeterminate (Exh. NG-KAK-4, at 194, 202-204). In support of her suggested average service life of 55, the Attorney General cites to utilities in Texas and Oklahoma that ostensibly use longer average service lives for underground conduits, but does not explain how these specific utilities serve as appropriate proxies for the Company (Exh. AG-DJG-1, at 32).[139] The Attorney General argues that her curve and average service life selections presenting an SSD of 0.5109 provide a better mathematical fit than the Company's calculated SSD of 1.6218 (Exhs. AG-DJG-1, at 33; AG-DJG-12). Given the insufficiency of retirement history, the Department finds that, like the statistical analyses, the mathematical fitting may not be adequately relied upon to suggest a departure from the currently approved average service life and curve. Therefore, the Department finds the Company's decision to retain the existing parameters and proposed accrual rate of 2.21 percent to be both reasonable and prudent given the limitations of the data. Accordingly, the Department approves the Company's proposed accrual rate of 2.21 percent.

(H) Account 367.10

The current accrual rate for Account 367.10 (Underground Conductors and Devices) is 2.90 percent (Exh. NG-KAK-3, at 17). National Grid proposes to replace the current

139 Geographical differences, as well as differences in system composition and retirement history render such comparisons relatively meaningless.

average service life of 45 and S0.5 curve with a 50-year average service life and an R0.5 curve, providing an accrual rate of 2.74 percent (Exhs. NG-KAK-3, at 17; NG-KAK-4, at 210). The Attorney General, in contrast, proposes an average service life of 53, an L0 curve, and an accrual rate of 2.49 percent (Exh. AG-DJG-1, at 7, 33-34). Account 367.10 includes the installed cost of underground conductors and devices used for distribution purposes (Exh. NG-KAK-4, at 210).

The majority of the statistical analyses for Account 367.10 exhibit low conformance indices, but also high enough levels of censoring to warrant caution in interpreting the results (Exh. NG-KAK-4, at 218-220). The shrinking band analysis does, however, indicate a potential trend of increasing average service lives from the existing average service life of 45 (Exh. NG-KAK-4, at 219). Looking at the actual observed data, both the Company and Attorney General acknowledge that there potentially exists an anomalous drop in the percentage of surviving assets at age 30 (Exhs. NG-KAK-Rebuttal-1, at 28; AG-DJG-1, at 34). Such nuances in the observed data are an excellent example of where judgment must be relied upon to suggest an appropriate parameter. While the Attorney General's proposed curve offers a marginally better mathematical fit with an SSD of 0.0217 compared to an SSD of 0.0591 for the Company's proposed curve, the difference in fit is nominal and does not consider the impact of an uncharacteristic retirement event (or events) on the data (Exhs. AG-DJG-1, 34-35; AG-DJG-13). Visually, the curves proposed by both parties appear to be within the range of reasonableness, but the Department considers the Company's proposal to have more appropriately factored the Company's specific history

(Exh. AG-DJG-1, at 34). Given the existing parameters for Account 367.10, the underlying retirement history, and the limited insights gained from the statistical analyses, the Department finds the Company's proposed accrual rate of 2.74 percent for Account 367.10 to be reasonable. Accordingly, the Department approves the Company's proposed accrual rate of 2.74 percent.

(l) Account 368.20

The current accrual rate for Account 368.20 (Line Transformers – Bare Cost) is 3.77 percent (Exh. NG-KAK-3, at 17). National Grid proposes to replace the current average service life of 32 and S1.5 curve with a 40-year average service life and an R4 curve, providing an accrual rate of 3.24 percent (Exhs. NG-KAK-3, at 17; NG-KAK-4, at 242). The Attorney General, in contrast, proposes an average service life of 44, an R5 curve, and an accrual rate of 2.91 percent (Exh. AG-DJG-1, at 7, 35-36).

Account 368.20 includes the investment in overhead and underground distribution line transformers used in transforming electric energy to secondary voltages (Exh. NG-KAK-4, at 242). The Company indicates that transformers are no longer repaired in-house and they are repaired and reused through an external vendor (Exh. NG-KAK-4, at 242).

The Company's rolling, shrinking, and progressing band life analysis for Account 368.20 do not adequately or conclusively support the Company's proposal, as a combination of higher conformance indices, censoring, and a shorter time period of data being analyzed (2004 through 2017) suggest that the statistical analysis alone may not identify the most reasonable curve and average service life selection (Exh. NG-KAK-4, at 249-252).

Moreover, the curve selected by the Company for this account, when inspected visually, underestimates the average service life compared to the actual data points representing the retirement history for this account (Exh. NG-KAK-4, at 255). In contrast, the 44 average service life R5 curve selected by the Attorney General has a better fit mathematically, with an SSD of 0.2140 compared to an SSD of 0.8442 for the Company's curve, as well as a better fit visually when looking at the actual history for this account (Exh. AG-DJG-1, at 36-37). Based on the Company's efforts to repair and reuse equipment in this account, the poor statistical results, and the superior fit both mathematically and visually of the Attorney General's proposal, the Department finds that an average service life of 44 and an R5 curve is reasonable for Account 368.20.

While the Department accepts the Attorney General's proposed average service life and curve selection, we do not adopt her proposed accrual rate of 2.91 percent. Consistent with the analysis in Section VIII.G.c.ii., above, the Department will recalculate the accrual rate for Account 368.20 using the Attorney General's parameters and the Company's redistributed recorded reserves. Based on the Attorney General's average service life and curve selection, Account 368.20 exhibits a composite average remaining life of 27.2 years (Exh. AG-DJG-16, at 25). Based on National Grid's reserve redistribution, Account 368.20 has a reserve ratio of 61.91 percent (Exh. NG-KAK-3, at 20, 22). With a proposed future salvage of negative 40 percent for Account 368.20 and the factors above, the Department calculates an updated accrual rate of 2.87 percent,[140] which when applied to the

[140] 0.0287 = (1.0 – 0.6191 – (-0.40)) / 27.2

Account 368.20 investment of $318,969,174, results in an annual accrual of $9,157,464 (Exhs. NG-KAK-3, at 16, 26; NG-KAK-4, at 43). Compared to the Company's proposed accrual of $10,334,601, the Department's calculated annual accrual represents a decrease to depreciation expense of $1,177,137.

iv. Conclusion

Based on the foregoing analyses, the Department finds that National Grid's proposal to redistribute its recorded reserve is appropriate in the instant circumstances. The Department also approves the accrual rates proposed by the Company for all plant accounts, with the exception of Account 355, Account 362, and Account 368.20, which are discussed in detail above. Therefore, the Department reduces the Company's proposed depreciation expense by $3,282,135.[141]

IX. GATEWAY ACCESS PROGRAM

A. Company Proposal

As part of its initial filing, National Grid proposed to implement a ratepayer-funded gateway access program ("GAP") to provide grants to qualified customers and developers to help offset electric infrastructure costs required to undertake certain redevelopment projects in gateway cities[142] located within the Company's service area (Exhs. NG-GAP-1, at 4, 6-7;

---

141 $3,282,135 = $305,356 + $1,799,642 + $1,177,137

142 The Legislature defines a "[g]ateway municipality" as a city or town with a population greater than 35,000 and less than 250,000, with a median household income below the Commonwealth's average, and with a rate of educational attainment of a bachelor's degree or above that is below the Commonwealth's average. G.L. c. 23A, § 3A. Gateway cities have been identified as ripe for economic

NG-HSG-12, Proposed M.D.P.U. No. 1401 (Bates Stamp 303-307)). According to the Company, gateway cities have the need and opportunity for economic revitalization, with the potential for new investment and job creation, but redevelopment projects in these cities may involve complex electric infrastructure upgrades, the cost of which can be prohibitive for the customer or developer undertaking the project (Exh. NG-GAP-1, at 6).

In an effort to reduce such cost barriers, the Company proposed to provide up to $3 million annually in grants over a five-year period,[143] for a total of up to $15 million (Exhs. NG-GAP-1, at 4, 13; NG-HSG-12, Proposed M.D.P.U. No. 1401. § 1.0, 2.1 (Bates Stamp 303)). National Grid estimated that program outreach, education, and communications will total an additional $50,000 per year over the five-year term of the program (Exh. NG-GAP-1, at 13). Further, the Company proposed that the maximum funding per project will be set at $250,000, and the grant amounts will be determined based on the total

---

revitalization, particularly by the Massachusetts Institute for a New Commonwealth, a nonprofit, nonpartisan entity organized under Section 501(c)(3) of the Internal Revenue Code (26 USC § 501(c)(3)) with a mission to identify and promote public policy that creates a pathway to opportunity for Massachusetts residents. See https://massinc.org/about-us/. There are 26 gateway cities in Massachusetts, 15 of which are in the Company's service area (Exh. NG-GAP-2, at 2; see also https://massinc.org/our-work/policy-center/gateway-cities/about-the-gateway-cities/). The gateway cities within National Grid's service area are: Attleboro, Brockton, Everett, Fall River, Haverhill, Lawrence, Leominster, Lowell, Lynn, Malden, Methuen, Quincy, Revere, Salem, and Worcester (Exhs. NG-GAP-1, at 5; NG-GAP-2, at 2; NG-HSG-12, Proposed M.D.P.U. No. 1401, § 2.6 (Bates Stamp 305)).

143 The Company stated that the program and all associated administrative processes will be ready for full operation by October 1, 2019, and will operate on an annual basis thereafter for five years (Exh. NG-GAP-1, at 13).

cost of the revitalization project, including eligible electric infrastructure costs and non-infrastructure costs such as site preparation, demolition and building renovation/construction costs (Exhs. NG-GAP-1, at 7; NG-GAP-2, at 1, 3-4; NG-HSG-12, Proposed M.D.P.U. No. 1401. § 2.1 (Bates Stamp 303)).[144]

Under the GAP proposal, to qualify for a grant, an applicant must satisfy certain eligibility requirements[145] and funding is limited to certain revitalization projects[146] located in gateway cities within the Company's service area (Exhs. NG-GAP-1, at 7; NG-GAP-2,

---

[144] Specifically, the Company proposed that for total project costs of $50,000 to $250,000, the maximum grant amount is $25,000; for total project costs of $250,000 to $1,000,000, the maximum grant amount is $50,000; for total project costs of $1,000,000 to $5,000,000, the maximum grant is $100,000; and for total project costs over $5,000,000, the maximum grant is $250,000 (Exhs. NG-GAP-2, at 4; NG-HSG-12, Proposed M.D.P.U. No. 1401. § 2.1 (Bates Stamp 304)). Further, grant amounts may not exceed 50 percent of the eligible electric infrastructure upgrade costs (Exhs. NG-GAP-2, at 4; NG-HSG-12, Proposed M.D.P.U. No. 1401. § 2.1 (Bates Stamp 304)).

[145] A qualified applicant must be: (1) a municipality and/or its authorized development corporation; (2) an organization with tax-exempt status pursuant to sections 501(c)(3) or 501(c)(6) of the Internal Revenue Code (26 USC §§ 501(c)(3), 501 (c)(6)) with the endorsement of the authorized municipality where the project is taking place; or (3) the owner or developer of an eligible facility or prospective eligible facility, with the endorsement of the local municipality; additionally, to be a qualified applicant, the applicant must demonstrate a track record and/or clear capability to successfully undertake and complete major redevelopment projects (Exhs. NG-GAP-1, at 9; NG-GAP-2, at 2; NG-HSG-12, Proposed M.D.P.U. No. 1401. § 2.8 (Bates Stamp 305)).

[146] The project must: (1) involve commercial, industrial, or mixed-use development; and (2) entail redevelopment of a building that has been vacant or underutilized (i.e., less than 25 percent occupied) for at least one year, a manufacturing facility, or a developable vacant site (Exhs. NG-GAP-2, at 2-3; NG-HSG-12, Proposed M.D.P.U. No. 1401. § 2.3 (Bates Stamp 304)).

at 2-3; NG-HSG-12, Proposed M.D.P.U. No. 1401, §§ 2.3, 2.8 (Bates Stamp 304-305)). Funding is further restricted to projects where the applicant is required to pay a CIAC pursuant to the Company's line extension policy for C&I customers contained in the terms and conditions for the distribution system tariff, and where the applicant can demonstrate that the existing electric infrastructure at the project site presents a barrier to completion of the proposed project (Exhs. NG-GAP-1, at 7; NG-GAP-2, at 3; NG-HSG-12, Proposed No. 1384, Appendix B, Policy 3 (Bates Stamp 153) & Proposed M.D.P.U. No. 1401. § 2.1, 2.3 (Bates Stamp 304)). Finally, an applicant must demonstrate that the project will lead to job creation and capital investment in the Company's service area (Exhs. NG-GAP-2, at 2-3; NG-HSG-12, Proposed M.D.P.U. No. 1401. § 2.3 (Bates Stamp 304)).

According to National Grid, grant applications will be processed on a first come, first served basis during each program year (Exh. NG-GAP-1, at 12). In addition to the applicant and project eligibility criteria specified above, National Grid proposed to evaluate applications on a variety of other factors, including the project's regional economic impact, ability to create/retain jobs, amount/diversity of leveraged funds, and the applicant's completion of the project with verification by National Grid (Exh. NG-GAP-2, at 3).[147] The Company noted that these factors may result in some applicants receiving less than the maximum grant award or no funding at all (Exh. NG-GAP-2, at 3).

---

[147] The Company noted that eligible projects that involve historic preservation or brownfield site redevelopment will be given priority consideration during the application evaluation process (Exh. NG-GAP-2, at 3).

Pursuant to the proposal, if an applicant's proposed project meets the aforementioned eligibility requirements and evaluation criteria, and funding is available, the application will be approved (Exh. NG-GAP-1, at 12). The Company noted that award letters will be sent to each successful applicant, detailing the amount of the grant award and the conditions for its disbursement, and an accompanying agreement will also be executed by the applicant and the Company (Exh. NG-GAP-1, at 12). Further, National Grid provided that grant funds will be paid to eligible applicants in a single payment and only upon certification of project completion,[148] obtained through a site visit and verification by a Company representative (Exhs. NG-GAP-1, at 13; NG-GAP-2, at 3; NG-HSG-12, Proposed M.D.P.U. No. 1401, § 2.1 (Bates Stamp 304)).[149] In addition, National Grid stated that it will seek to distribute program funding equitably across the 15 gateway cities, but the Company intends to consider inherent differences in economic conditions and customer/developer demand across the cities in making funding decisions (Exhs. NG-GAP-1, at 12; NG-GAP-2, at 3).

Finally, regarding cost recovery, the Company proposed to implement the GAP provision, a reconciling mechanism that will recover from all customers the amount of grants

---

148 Thus, although a primary purpose of the GAP proposal, as set forth by the Company in its initial filing, is to reduce the CIAC-related cost barriers faced by developers, grants are payable only upon completion of a project, thereby requiring the applicant to secure preliminary funding in the amount of the grant from another source (Exh. NG-GAP-2, at 3; Tr. 7, at 864-865).

149 The Company explained that the verification process will include documentation that all costs have been incurred by the applicant as per the approved project scope of work and accompanying budget (Exhs. NG-GAP-1, at 13; NG-GAP-2, at 3). National Grid stated that under no circumstances will grant funds be "advanced" for costs not yet incurred by the applicant (Exhs. NG-GAP-1, at 13; NG-GAP-2, at 3).

disbursed to eligible applicants during the prior GAP year, plus actual outreach, education, and communication costs incurred during that prior GAP year (Exhs. NG-GAP-1, at 14-15; NG-HSG-12, Proposed M.D.P.U. No. 1401 (Bates Stamp 303-307)). National Grid proposed to submit, by January 1 of each year, an annual filing of costs incurred through each September 30 of the previous year (Exh. NG-GAP-1, at 15; NG-HSG-12, Proposed M.D.P.U. No. 1401 (Bates Stamp 304)).[150] Pursuant to the proposal, upon review and approval of the filing by the Department, the Company will implement the gateway access factor and the gateway access reconciliation factor, each with an effective date of March 1, to recover costs from all customers (Exhs. NG-GAP-1, at 14-15; NG-HSG-12, Proposed M.D.P.U. No. 1401, §§ 2.4, 2.5 (Bates Stamp 304)).[151] Further, National Grid proposed that any reconciliation balances associated with the difference between the revenues billed through the tariff and those allowed for recovery will be determined on a monthly basis and

---

150 The Company also proposed to include in the GAP annual cost recovery filing details on the awards made through the program and the total amounts dispersed (Exh. NG-GAP-1, at 14). Specifically, National Grid proposed that it will track all grants distributed as part of the GAP, and that the annual filing will include: (1) grants distributed during the prior year; (2) recipients, grant amounts, and project location; and (3) any known impacts, such as new capital investment, job creation, and other impacts (Exh. NG-GAP-1, at 14). The Company also proposed to survey customers upon a project completion in order to validate project impacts and obtain feedback on the GAP and process (Exh. NG-GAP-1, at 14).

151 National Grid proposed per-kWh rates for both factors, with the amount to be recovered allocated to the Company's rate classes based upon the Distribution Revenue Allocator as approved by the Department (Exhs. NG-GAP-1, at 15; NG-HSG-12, Proposed M.D.P.U. No. 1401, §§ 3.1, 3.2 (Bates Stamp 305-306)). The Company proposed for the factors to be included with the distribution per-kWh charge on customers' bills (Exhs. NG-GAP-1, at 15; NG-HSG-12, Proposed M.D.P.U. No. 1401, § 3.4 (Bates Stamp 307); RR-DPU-16).

include carrying charges, calculated on the monthly balance, at the customer deposit rate (Exh. NG-HSG-12, Proposed M.D.P.U. No. 1401, § 4.1 (Bates Stamp 307)).

B. Positions of the Parties

1. Attorney General

The Attorney General argues that rather than approve the Company's GAP proposal, the Department should open a general investigation into the Company's line extension policy to determine the specific barriers to CIAC affordability and interconnection across the Company's entire service area (Attorney General Brief at 128-129, 132). The Attorney General claims that the Company's CIAC requirements associated with its line extension policy create challenges to C&I project development that are not limited to the selected cities that the GAP proposal targets (Attorney General Brief at 128-129).

Alternatively, the Attorney General argues that, if the Department does approve the GAP proposal, it should require the Company to (1) make all GAP eligibility and evaluation criteria clear and transparent and (2) demonstrate that the program is achieving its claimed benefits for ratepayers (Attorney General Brief at 129, 132-135). Regarding eligibility and evaluation criteria, the Attorney General contends that National Grid's determination of project eligibility, its weighing of evaluation factors, and its ultimately funding decisions for the GAP program, are not clear from the face of the proposed tariff provision or the Company's own written program description (Attorney General Brief at 132-134). Thus, the Attorney General claims that National Grid should (1) provide a consistent and detailed explanation of any factors that the Company will consider in evaluating applications, and

(2) explain how it would weigh any and all eligibility and grant determination factors (Attorney General Brief at 134). In addition, the Attorney General contends that the proposed GAP tariff should contain detailed filing requirements for the Company's cost recovery filing including (1) documentation of each project application, (2) a detailed description and supporting documentation regarding how the Company determined the existence of a barrier/financial need, (3) a detailed description and supporting documentation on how the Company evaluated the eligibility and evaluation factors of each project, (4) whether a project was approved for funding, and (5) the evaluation that the Company undertook in determining the grant amount (Attorney General Brief at 134-135).

With respect to ratepayer benefits from the GAP, the Attorney General argues that the GAP proposal does not include any express mechanism for measuring any ratepayer benefits and that there is no requirement for applicants to provide such benefits as a condition to receiving GAP funding (Attorney General Brief at 135, citing Exhs. NG-GAP-1, at 14; NG-HSG-12, at 303-307). Thus, the Attorney General contends that in the annual cost recovery filing, the Company should measure and report whether the program is achieving each of its claimed benefits on behalf of all ratepayers, including but not limited to the following: (1) regional economic impact; (2) job creation; (3) job retention; (4) higher regional earnings in gateway cities and surrounding communities; (5) customer bill impacts/reduction in cost responsibilities in relation to the Company's base revenue requirement and reconciling factors; and (6) new capital investment (Attorney General Brief at 136, citing Exhs. NG-GAP-1, at 8-9; AG 11-4; AG 11-13; DPU-NG 2-16). The Attorney

General posits that the Company also should incorporate a provision in the GAP tariff to reflect these filing requirements (Attorney General Brief at 136).

2. Company

National Grid argues that the GAP proposal will provide essential targeted financial assistance, in the form of grants, to offset costs for specific electric infrastructure and distribution system projects in gateway cities in the Company's service area (Company Brief at 423). According to the Company, the GAP is designed to address the needs of customers, incentivize developers, and provide customer benefits in the form of new and retained jobs, new capital investment, and higher regional earnings in the gateway cities (Company Brief at 423).[152]

The Company maintains that it is receptive to working with the Attorney General, the Department, and other stakeholders to tailor the GAP to achieve its intended purposes (Company Brief at 434). In this regard, the Company, on brief, states that it is "receptive to expanding" GAP eligibility to municipalities that have a minimum population of 2,500 and have at least 20-percent low-income customers (i.e., seven additional municipalities) (Company Brief at 435). The Company contends that, as it gains more experience and insight into providing grants through the GAP, it may reassess and expand the GAP to other municipalities (Company Brief at 435). Nonetheless, the Company argues that it is not necessary for the Department to conduct an investigation into the interconnectivity issues

[152] The Company devotes numerous pages of its brief describing the particulars of the GAP program and summarizing the Attorney General's position (Company Brief at 423-434). The Department will not rehash these portions of the brief here.

experienced by the Company's C&I customers outside of the gateway cities as (1) the Company already has acknowledged that C&I customers outside of the gateway cities have experienced cost-related interconnection issues and (2) the GAP is targeted at mitigating prohibitive cost barriers for revitalization projects that will preserve and retain jobs in economically disadvantaged communities, not at alleviating interconnectivity cost issues for C&I customers (Company Brief at 435-436).

Regarding the Attorney General's concerns on providing transparent eligibility and evaluation criteria, the Company proposes, on brief, to: (1) consider establishing a "small and medium business" preference for GAP project applicants based on Small Business Association criteria such as the number of employees and the industry the applicant operates in; (2) give preference to the type of project that an applicant proposes (e.g., adaptive use, repurposing, and revitalization projects); and (3) add a "local business" criteria that would give preference to projects developed or owned by a person or entity within the Company's service area (Company Brief at 436).[153] Further, in an effort to better evaluate an applicant's financial need or barrier to completing a project, the Company, on brief, states that: (1) it is receptive to using a third party to review and evaluate an applicant's financial needs, though this may add complexity and extend the applicant review process; or (2) as an alternative to using a third party, the Company could use financial ratios or metrics that the Attorney

---

[153] The Company states that it would welcome feedback from the Attorney General, Department, and other stakeholders on other options to modify applicant requirements as it refines GAP parameters (Company Brief at 437).

General, Department, or other stakeholders suggest[154] (Company Brief at 437-438, citing Tr. 7, at 879).

Finally, in response to the Attorney General's concerns on the reporting of ratepayer benefits and other requirements for the annual filing, National Grid maintains that it intends to work with the Attorney General and the Department to provide the type of documentation to demonstrate the GAP's realized benefits and the structure of the annual report (Company Brief at 438). In this regard, the Company proposes that its annual GAP filing include documentation of each project that received GAP funding over the prior year including (1) where the projects are located, (2) how much funding was awarded to each project, (3) how much funding was awarded to various municipalities, (4) the number of jobs created or retained by each project, (5) customer bill impacts/reduction in cost responsibilities in relation to the Company's base revenue requirement and reconciling factors, and (6) new capital investment (Company Brief at 438, citing Exhs. NG-GAP-1, at 8-9, 14; AG 11-4; AG 11-3; DPU-NG 2-16; Tr. 7, at 870).

C. Analysis and Findings

As noted above, National Grid proposes to provide up to $3 million annually in grants to qualified customers and developers to help offset electric infrastructure costs required to undertake certain redevelopment projects in gateway cities located within the Company's service area (Exhs. NG-GAP-1, at 4, 6-7; NG-HSG-12, Proposed M.D.P.U. No. 1401

---

154 In particular, National Grid states that one metric it could use would compare the ratio of the CIAC amount to total project budget to set a minimum percentage threshold for a project's eligibility (Company Brief at 437).

(Bates Stamp 303-307)). The Department applauds National Grid's efforts to address the prohibitive nature of CIAC-related costs through its targeted GAP proposal. After careful review and consideration, however, the Department is not persuaded that the current GAP proposal is in the public interest.

In particular, pursuant to the GAP proposal, costs would be borne entirely by the Company's customers, including those who do not reside in gateway cities (Exhs. NG-GAP-1, at 14; NG-HSG-12, Proposed M.D.P.U. No. 1401 (Bates Stamp 303-307)).[155] Thus, at least on the surface, the proposal is inconsistent with established cost causation principles in ratemaking. Bay State Gas Company, D.T.E./D.P.U. 06-36, at 41 (2007); D.P.U. 96-50 (Phase I) at 133-134. National Grid contends that its cost recovery proposal is appropriate because revitalization projects under the program would benefit all customers. Specifically, the Company states that the program will: (1) generate direct customer benefits, such as new jobs and economic investment in the gateway cities where the projects are located;[156] (2) result in indirect customer benefits for

---

155 As noted above, National Grid proposes to recovery costs through a fully reconciling mechanism. Given our findings, however, we need not determine at this time whether the Company's proposal meets the Department's standard for approval of a fully reconciling mechanism. See, e.g., D.P.U. 10-70, at 48; D.P.U. 10-55, at 66 n.43; D.P.U. 07-50-A at 50; D.T.E. 05-27, at 183-186; Boston Edison Company/Cambridge Electric Light Company/Commonwealth Electric Company/NSTAR Gas Company, D.T.E. 03-47-A at 25-28, 36-37 (2003); Eastern Enterprises/Essex County Gas Company, D.T.E. 98-27, at 6, 28 (1998).

156 Based on its analysis from similar existing programs currently operating in the upstate New York service territory of its affiliate Niagara Mohawk Power Corporation, National Grid estimates that the GAP could create or retain as many as 7,000 jobs and leverage as much as $750 million in other public and private investment, if the

neighboring cities and towns; and (3) reduce all customers' cost responsibilities in terms of contributions to the Company's revenue requirement and reconciling factors (Exhs. NG-GAP-1, at 8-9; DPU-NG 2-16; DPU-NG 2-20; AG 11-3; AG 11-4; AG 11-5 & Att.; AG 33-31; AG 33-32; AG 33-34; AG 33-35; AG 33-36; Network 2-9; Tr. 7, at 852-855; RR-DPU-15(a)).

National Grid did not perform a cost/benefit analysis relative to the GAP proposal, and the Company concedes that the extent of customer benefits is dependent on the level of future economic activity and the number of GAP-related projects in each gateway city (Exhs. AG 14-15; AG 33-31; AG 33-36; Tr. 7, at 856). Further, the record shows that the Company's estimates regarding direct benefits for Massachusetts gateway cities are based only upon its analysis of data from similar programs in upstate New York (Exhs. NG-GAP-1, at 8-9; AG 11-5 & Att.). In addition, the Company's evaluation of potential increases to revenues and corresponding decreases to customers' rates is based on multiple assumptions regarding project size and rate class contribution to overall revenues, which could produce unreliable conclusions (Exh. DPU-NG 11-15 (Supp.) & Att.; RR-DPU-15(a)). Moreover, although the Company agreed to provide the Department with annual filings that contain certain information regarding new capital investment, job creation, and other impacts of the proposal, the Company did not propose any standards or metrics for

---

proposed level of funding is fully utilized over the five-year term of the program (Exhs. NG-GAP-1, at 8-9; AG 11-5 & Att.).

measuring the extent of the anticipated benefits, or ensuring that customers realize a certain level of benefits (Exh. NG-GAP-1, at 14; Tr. 7, at 870-871).

In sum, we find the potential customer benefits that would result from the proposed GAP, particularly across the Company's entire service area, rest on significant speculation and uncertainty. Therefore, without substantial evidence that customers across National Grid's entire service area will demonstrably benefit from their contribution to the program, the Department is not persuaded that the proposed GAP, as currently designed, strikes an appropriate balance between the objective of reducing CIAC-related cost barriers and the Company's obligation to provide least-cost service to all of its customers.

In addition to the cost recovery considerations, the Department is concerned that material aspects of the GAP proposal, as delineated in the Company's initial filing[157] and further described through discovery and the evidentiary hearings, are not clearly defined, sufficiently transparent, or fully developed. For instance, the proposed GAP includes specific applicant and project eligibility requirements (Exhs. NG-GAP-1, at 9; NG-GAP-2, at 2-3; NG-HSG-12, Proposed M.D.P.U. No. 1401. §§ 2.2, 2.3 (Bates Stamp 304)). Among other things, an applicant must demonstrate that the existing electric infrastructure is insufficient to serve the proposed development and that the proposed upgrades to the infrastructure pose a financial challenge to the project's completion (Exhs. NG-GAP-2, at 3;

[157] In its initial filing, the Company provided prefiled testimony regarding the particulars of the GAP proposal, a written description of the proposed program, and a proposed GAP tariff provision (Exhs. NG-GAP-1; NG-GAP-2; NG-HSG-12, Proposed M.D.P.U. No. 1401 (Bates Stamp 303-307)).

NG-HSG-12, Proposed M.D.P.U. No. 1401. § 2.3 (Bates Stamp 304); AG 11-8). The GAP-related documentation provided by the Company, however, neither defines a "financial challenge" nor provides any guidance as to how the Company would determine financial need, and the Company has conceded that there is no threshold test for meeting this requirement (Tr. 7, at 844-845).[158]

In addition to specific applicant and project eligibility requirements, the proposed GAP includes certain applicant evaluation criteria (Exhs. NG-GAP-1, at 12; NG-GAP-2, at 3). The record, however, lacks a written description of the actual application-review process, and the Company has not finalized the details of the review process, including whether or how the evaluation criteria would be scored or weighted to select among competing projects (Tr. 7, at 848-850, 867-869).

Given that the GAP program is intended to address CIAC-related cost barriers facing qualified developers, the Department finds that a well-defined, transparent program should include specific, objective criteria for determining an applicant's financial need. Further, in order to facilitate consistent treatment of qualified applicants and the fair distribution of

---

[158] National Grid expressed some willingness to consider a third party to review and evaluate an applicant's financial position, but on brief noted that this arrangement is not ideal, as it would add complexity and lag time to the process and could create negative customer relation issues (Tr. 7, at 874; Company Brief at 437). Further, on brief, the Company argued that financial need could be evaluated by comparing the CIAC amount to the total project budget and setting a minimum percentage threshold for a project's eligibility (Company Brief at 437). However, this concept is not fully developed in the record and neither the Attorney General nor the Department had an opportunity to adequately investigate this option.

grants throughout the various gateway cities, we find that a well-defined, transparent program should include specific, objective applicant evaluation criteria.[159]

Regarding this last point, National Grid stated that it would seek to distribute grants equitably across the gateway cities, but funding decisions also would take into account inherent differences in economic conditions and customer/developer demand across the cities and seek to maximum benefits for the Company's service area as a whole (Exhs. NG-GAP-1, at 12; AG 14-18). The Department recognizes that an equal distribution of GAP funds across the gateway cities may not be achievable and that the level of economic activity and the number of eligible projects in each gateway city would be relevant factors in determining project approval and how GAP funds should be distributed (Exh. AG 14-18; Tr. 7, at 856). It stands to reason, however, that CIAC-related cost barriers exist in many, if not all, of the gateway cities within the Company's service area, and that qualified applicants would be available in a number of these cities (see Exhs. AG 33-33; AG 33-34). Therefore, the Department finds that a well-defined, transparent program would consider specific measures to ensure that funds are fairly distributed across the gateway cities in the Company's service territory.

---

159 On brief, the Company offered to refine the GAP proposal to give preferences to small and local businesses and certain types of projects in order to facilitate the application review process and, in particular, the determination of financial need (Company Brief at 436-437). This concept is not fully developed in the record and neither the Attorney General nor the Department had an opportunity to adequately investigate the Company's offerings.

Based on the above considerations, the Department rejects the Company's GAP proposal, as filed. During the evidentiary hearings and on brief, the Company noted that it was willing to work with the Department and Attorney General to resolve any concerns about the GAP proposal (Tr. 7, at 857, 870-871; Company Brief at 437-438). The Department is not inclined, however, to address the above considerations during a compliance phase of the instant proceeding. Rather, we find that it would be more appropriate and efficient to evaluate any modified GAP proposal in a new proceeding outside of the context of a base distribution rate case.

In this regard, we note that while the GAP proposal is targeted toward the 15 gateway cities within the Company's service area, other cities and towns (including the remaining gateway cities in other service territories) across the Commonwealth may face similar CIAC-related cost barriers to redevelopment (see Exh. AG 33-31). Therefore, we encourage National Grid to consider a joint filing with NSTAR Electric and Fitchburg Gas and Electric Light Company, d/b/a Unitil ("Unitil") to address CIAC-related cost barriers across the Commonwealth where there is a need and a strong potential for economic revitalization.[160] As part of any future filing, the Department expects the electric distribution companies to seek appropriate stakeholder input, including from the Attorney General, city and town officials, and economic development coordinators (see, e.g., Exh. DPU-NG 2-17 (Rev.)). The Department also expects that any filing would take into account the various

160 We also note that other sources of funding are available to gateway city developers, including government grants at the federal, state, and local level (see, e.g., Exh. DPU-NG 11-13).

considerations discussed above, including, in particular, the need to provide substantial evidence of potential benefits for all customers. Moreover, we expect the petitioners to demonstrate how any proposal that seeks to recover all costs on a reconciling basis meets the Department's standard for approval of a fully reconciling mechanism (see n.155, above).

Finally, as noted above, the Attorney General argues that the Department should open a general investigation into the Company's line extension policy to determine the specific barriers to CIAC affordability and interconnection across the Company's entire service area (Attorney General Brief at 128-129, 132). To the extent that the Department receives any future filing to address CIAC-related issues, the Attorney General will have an opportunity to participate in that proceeding.[161] At this time, however, we decline to open a general, broader proceeding to address these issues.

X. ENERGY STORAGE DEMONSTRATION PROGRAM

A. Introduction

National Grid proposes to invest $50 million over five years on up to 14 MW, or 56 megawatt hours ("MWh"), in an energy storage demonstration program (Exh. NG-FED-1, at 2, 8).[162] The Company proposes to recover the costs through its grid

---

161 The Department notes that it recently opened an investigation into distributed generation interconnection issues. D.P.U. 19-55 (May 22, 2019).

162 The Company anticipates that the capital costs, in aggregate, will be approximately $42 million and proposes $50 million as a cap on overall costs for the program (Exh. NG-FED-1, at 8 n.8, 17).

modernization recovery provision (Exh. NG-FED-1, at 23).[163] Specifically, the Company proposes to recover the annual revenue requirement of the energy storage systems installed, consisting of capital investments and O&M expense (Exh. NG-FED-1, at 24).

The Company states that the storage program will (1) demonstrate the value of energy storage to solve distribution needs within the electric power system, (2) improve electric power system performance during peak energy use periods, (3) make further progress in meeting service quality goals, and (4) aid in assessing the ability of storage to support the integration of renewable energy into the Company's service area (Exh. NG-FED-1, at 2-3). The Company has identified three potential projects that are located in Westport, Ayer, and Rockport (Exh. NG-FED-1, at 11-14).

B. Proposed Projects

1. Westport

National Grid states that the Westport area is served by a single feeder, making it vulnerable to a single element outage, or N-1 contingency (Exh. NG-FED-1, at 11-12).[164] Accordingly, the Company proposes to install (1) a backup tie between two substations and (2) a four-MW, or 16-MWh, energy storage system to supplement the backup tie

163 The Company has proposed revisions to its grid modernization recovery provision to include cost recovery for its energy storage demonstration program (Exh. NG-HSG-13, proposed M.D.P.U. No. 1398 (Bates Stamp 267-272)).

164 A single grid element failure, requiring the shift of load elsewhere in the distribution system to meet customer service needs, is referred to as an N-1 contingency (Exh. NG-FED-1, at 9 n.9). Reliability criteria to withstand credible contingencies are set by the North American Electric Reliability Corporation subject to oversight by FERC and governmental authorities in Canada.

(Exh. NG-FED-1, at 12). National Grid states that without the energy storage facility, the Company would have to build a new feeder, which would require substantial permitting and construction costs (Exh. NG-FED-1, at 12).

In addition to solving N-1 contingency needs in the area, the Company expects to leverage the opportunity to explore the operational requirements needed to enable a utility-scale energy storage asset to allow for the increased penetration of distributed generation (Exh. NG-FED-1, at 12). Currently, there is 5.8 MW of interconnected distributed generation and an additional 11.1 MW of open interconnection applications (Exh. NG-FED-1, at 12). The Company estimates that the total capital cost for the Westport project will be $12 million (Exh. NG-FED-1, at 17).

2. Ayer

National Grid states that the summer peak load in the Ayer area results in the feeder reaching approximately 97 percent of its summer normal rating (Exh. NG-FED-1, at 12-13). The Company proposes to install a five-MW, or 20-MWh, energy storage system and leverage existing backup ties to the feeder to address this issue (Exh. NG-FED-1, at 13). The Company states that a traditional solution would be to add a new feeder, which would require upgrades to the substation as it does not have space for additional feeders (Exh. NG-FED-1, at 13). The Company estimates that the total capital cost for the Ayer project will be $15 million (Exh. NG-FED-1, at 17).

3. Rockport

National Grid states that a substation is expected to be rebuilt in the next five to seven years due to asset condition issues in the Rockport area, which will require the load to be shifted to two different sub-transmission lines (Exh. NG-FED-1, at 13). To ensure that N-1 contingency criteria are met during this process, the Company proposes to install a five-MW, or 20-MWh, energy storage system that would serve load locally when one of the two lines is out of service in order to avoid overloading the supply line in service (Exh. NG-FED-1, at 13-14). National Grid states that, without the energy storage system, the two sub-transmission lines would need to undergo major work in the downtown Gloucester area (Exh. NG-FED-1, at 13-14). The Company estimates that the total capital cost for the Rockport project will be $15 million (Exh. NG-FED-1, at 17).

C. Positions of the Parties

1. Attorney General

The Attorney General contends that the Department established comprehensive standards for review and preauthorization of demonstration projects (Attorney General Brief at 196-197, citing D.P.U. 17-05, at 457; D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 220). The Attorney General outlines the four factors used by the Department in D.P.U. 17-05, at 457: (1) the consistency of the proposed demonstration program with applicable laws, policies, and precedent; (2) the reasonableness of the size, scope, and scale of the proposed projects in relation to the likely benefits to be achieved; (3) the adequacy of the proposed performance metrics and evaluation plans; and (4) bill impacts to customers

(Attorney General Brief at 196-197). The Attorney General argues that the Department cannot approve the request for preauthorization because National Grid has not provided the information necessary to determine the prudence of the proposed investment or the reasonableness of the size, scope, and scale of the proposed projects in relation to the likely benefits to be achieved (Attorney General Brief at 194; Attorney General Reply Brief at 68).

The Attorney General argues that the Company must submit conceptual design reports or similar analyses to substantiate economic and technical feasibility of energy storage demonstration projects prior to Department approval (Attorney General Brief at 198). For comparison, the Attorney General points to the information provided in the battery storage proposal submitted to the Department by NSTAR Electric in D.P.U. 17-05 (Attorney General Brief at 199, citing D.P.U. 17-05, at 461-463). The Attorney General asserts that the Department sought supporting documentation from National Grid during this proceeding, and the Company stated it would not be completing any conceptual design studies for twelve to 18 months (Attorney General Brief at 198, citing Exh. DPU-NG 4-1). The Attorney General maintains that the Company conceded during the proceeding that its conceptual design work to date consisted solely of knowledgeable Company planners and engineers, who are familiar with the characteristics of the proposed demonstration locations, conducting "whiteboard" considerations of various load serving scenarios, which the Attorney General contends lacks formal computer-detailed analysis and engineering rigor (Attorney General Brief at 199, citing Tr. 2, at 207, 280-281). Based on these factors, the Attorney General recommends that the Department deny the Company's proposal without prejudice and direct National Grid to refile its energy storage proposal to coincide with its July 1, 2020 grid modernization plan (Attorney General Brief at 194, 200-201; Attorney General Reply Brief at 71).

2. DOER

DOER maintains that, under Department precedent, National Grid must support its proposal with cost-effectiveness screenings allowing the Department and stakeholders to evaluate the reasonableness of the size, scope, and scale of the proposed storage project in relation to the benefits to be achieved (DOER Brief at 36, citing D.P.U. 17-05, at 460). DOER acknowledges that the Company has not yet completed a distribution area feasibility study for the three proposed projects, and, therefore, there is insufficient information to analyze the size, scope, and scale of the proposed projects (DOER Brief at 36; DOER Reply Brief at 21). Nonetheless, DOER recommends approving the Company's proposal subject to the condition that the Company provide, in a compliance filing, a feasibility study that shows ratepayer benefits (DOER Brief at 36; DOER Reply Brief at 20). DOER argues that if the Company is unable to show that any project is cost effective to ratepayers, the Department may then deny recovery of the costs relating to the project (DOER Brief at 36). DOER recommends this alternative path to avoid the potential for regulatory delay (DOER Reply Brief at 21).

3. NECEC

NECEC strongly supports the adoption of energy storage in the Commonwealth (NECEC Brief at 38). NECEC argues, however, that the Company should be prohibited from owning behind-the-meter storage (NECEC Brief at 38-39). NECEC states that every project where National Grid deploys behind-the-meter storage represents a lost opportunity for the storage industry to develop and mature (NECEC Brief at 41, citing Exh. NECEC-NP-1, at 43). NECEC maintains that the full revenue requirement associated with the proposed storage program will be $86 million rather than the stated cost of $50 million (NECEC Brief at 41-42, citing Tr. 2, at 254-255; RR-NECEC-2). NECEC argues that third-party developers are best positioned to make the direct investments in energy storage, as they can do so without the incremental expenditure of ratepayer dollars (NECEC Brief at 42).

4. Tesla

Tesla states, without any supporting analysis, that the Company's proposed energy storage program should be approved (Tesla Brief at 1, 18; Tesla Reply Brief at 1, 10).

5. Company

The Company contends that its energy storage proposal should be approved (Company Reply Brief at 148-149). The Company maintains that its proposal meets the four-factor standard for reviewing preauthorization of demonstration projects outlined by the Department (Company Brief at 399-413, citing D.P.U. 17-05, at 457). Specifically, the Company maintains that its storage proposal supports state and regional policy goals, including reducing GHG emissions and helping to achieve the Commonwealth's energy storage target (Company Brief at 400-401). The Company also contends that, contrary to the Attorney General's assertions, National Grid provided sufficient information to determine that the size, scope, and scale of its proposed energy storage program is reasonable (Company Brief at 401-405; Company Reply Brief at 145-146). National Grid disagrees with the Attorney General's assertion that there is not sufficiently detailed information to preauthorize the Company's proposed energy storage program (Company Brief at 416-417). National Grid maintains that it provided information analogous to that provided by NSTAR Electric in D.P.U. 17-05 and approved by the Department (Company Brief at 418-420, citing Exhs. NG-FED-1, at 5, 6-7, 11-12; DPU-NG 4-2; AG 21-1; AG 21-2; Tr. 2, at 204, 220-222, 287, 289-292; Company Reply Brief at 145). National Grid also contends that in D.P.U. 17-05, the Department approved NSTAR Electric's storage demonstration project even though NSTAR Electric had not yet provided a fully completed and detailed engineering and feasibility analysis (Company Reply Brief at 146-147, citing D.P.U. 17-05, at 463-465 nn.224, 226).

The Company maintains that DOER's proposal to allow for a separate compliance filing is unnecessary as National Grid will submit sufficient data through its pending distribution area planning studies (Company Brief at 423). The Company also maintains that the regulatory lag related to a separate proceeding, which would likely include an evidentiary hearing, would delay benefits and potentially lead to higher costs for ratepayers (Company Brief at 423).

D. Analysis and Findings

The Department is generally supportive of National Grid's effort to implement energy storage demonstration projects, and the Department is committed to the Commonwealth's policy objectives for energy storage. D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 3-6.

In evaluating National Grid's proposed storage demonstration projects, the Department considers the following criteria: (1) the consistency of the proposed demonstration program with applicable laws, policies, and precedent; (2) the reasonableness of the size, scope, and scale of the proposed projects in relation to the likely benefits to be achieved; (3) the adequacy of the proposed performance metrics and evaluation plans; and (4) bill impacts to customers. D.P.U. 17-05, at 457; NSTAR Electric Company/Western Massachusetts Electric Company, D.P.U. 16-178, at 25-26 (2017).

We first consider whether the Company has submitted sufficient supporting documentation to demonstrate the reasonableness of the size, scope, and scale of the proposals in relation to the benefits to be achieved. D.P.U. 17-05, at 460; D.P.U. 16-178, at 30; Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 11 (2017). We have previously stated that in the absence of cost-effectiveness screenings, the Department requires detailed program descriptions and appropriate analyses to support the potential of the proposals to deliver net benefits in the future. D.P.U. 17-05, at 460; D.P.U. 16-178, at 30; D.P.U. 16-184, at 11. When asked to provide all workpapers and analyses used to formulate and justify the Company's storage proposal, the Company provided a one-page project opportunity brief and fact sheets outlining the proposed projects (Exh. AG 21-2, Atts.). The Company did not provide conceptual design reports or distribution area studies. Thus, we disagree with National Grid's assertion that it provided evidence analogous with that provided by NSTAR Electric in D.P.U. 17-05. For example, National Grid stated that it had not yet developed conceptual design reports because the development process had not yet progressed to this point (Exh. DPU-NG 4-1). The Company also stated that it was in the process of conducting distribution area studies and provided anticipated completion dates of the first, third, and fourth quarters of 2020 for Westport, Ayer, and Rockport, respectively (Exhs. DPU-NG 14-1; DPU-NG 21-3). In contrast, NSTAR Electric provided the requested conceptual design reports conducted by third-party vendors as well as other supporting documentation. See, e.g., D.P.U. 17-05, at 462, citing Exhs. AG 23-13; AG 32-3, Att. (b). Further, where NSTAR Electric did not provide sufficient supporting documentation for certain projects, the Department determined it was unable to review those projects and make the necessary assessment. D.P.U. 17-05, at 465-466, 471.

Based on the record in this proceeding, the Department finds that the information provided is insufficient at this time for the Department to make any finding on the reasonableness of size, scope, and scale of the program in relation to the likely benefits to be achieved.[165] Because the Company has not met its burden to provide sufficient evidence to satisfy this criterion, the Department need not address whether the Company's proposal meets the other three criteria. Based on the foregoing, the Department denies National Grid's proposal to recover, through its grid modernization recovery provision, the annual revenue requirement of the energy storage systems installations, consisting of capital investments and O&M expense. The Department also denies the Company's proposed changes to its grid

165 DOER's alternative proposal, to approve the proposal subject to a compliance filing, is inconsistent with Department precedent, and we decline to take such an approach. D.P.U. 17-05, at 465-466, 471.

modernization provision tariff consistent with the findings herein (Exh. NG-HSG-13, proposed M.D.P.U. No. 1398 (Bates Stamp 267-272)).

The Attorney General recommends that the Department direct National Grid to refile its energy storage proposal to coincide with its July 1, 2020 grid modernization plan. Based on the record evidence in this proceeding, we recognize that the Company may not yet have the appropriate supporting documentation for its July 1, 2020 filing. Thus, the Company may submit an updated energy storage demonstration project proposal when the appropriate information becomes available.[166] Nonetheless, if the Company has completed the necessary supporting documentation for its next grid modernization plan filing, the Company may include energy storage system installations for review. Further, the Department is interested in different approaches that companies may use for non-wires alternatives, as well as the potential for company-owned energy storage to defer capital investments, lower wholesale market costs, improve reliability, and accommodate the integration of DER. We encourage the Company to consider including these approaches in its updated energy storage demonstration proposal (Exh. NG-FED-1, at 11-12).

---

166 Any proposal submitted by the Company must meet the four factors for review of demonstration projects. D.P.U. 17-05, at 457; D.P.U. 16-178, at 25-26. Additionally, the Company's proposed cost cap of $50 million appears to be an appropriate control for this type of demonstration program.

XI. PHASE II ELECTRIC VEHICLE PROGRAM

A. Background

The Commonwealth has supported EV implementation in several ways in an effort to reduce GHG emissions in the transportation sector. For example, on September 30, 2013, the Executive Office of Energy and Environmental Affairs convened the Massachusetts EV initiative task force, which included numerous public and private stakeholders. Electric Vehicles, D.P.U. 13-182, at 2 (2012). Further, on October 24, 2013, Massachusetts joined seven states as a signatory to the State ZEV Programs Memorandum of Understanding setting a collective target of having at least 3.3 million ZEVs on their roads by 2025.[167] In addition, in September 2016, Governor Baker issued an Executive Order that directed the Secretary of Energy and Environmental Affairs to work in consultation with state and regional agencies that manage transportation, environment, and energy issues to develop regional policies to reduce GHG from the transportation sector, consistent with meeting the 2050 emissions limits of the Global Warming Solutions Act.[168] Executive Order No. 569: Establishing an Integrated Climate Change Strategy for the Commonwealth (September 16, 2016). Furthermore, since 2014, the Commonwealth has leveraged more than $30 million in funds

---

[167] http://www.nescaum.org/topics/zero-emission-vehicles

[168] The Global Warming Solutions Act, codified as G.L. c. 21N, establishes limits on GHG emissions in the Commonwealth and directs state agencies to promulgate regulations that reduce energy use, increase efficiency, and encourage renewable sources of energy in the sectors of energy generation, buildings, and transportation. G.L. c. 21N, § 6.

generated from the Regional Greenhouse Gas Initiative and Alternative Compliance Payments to provide EV rebates.[169]

Along with the foregoing efforts, on December 23, 2013, the Department issued a notice of investigation into EVs and EV charging. D.P.U. 13-182, at 4. The Department recognized that the widespread adoption of EVs in the Commonwealth will improve air quality, reduce GHG emissions from the transportation sector, and require adding new technologies to the electric grid, including an increase of EV-related infrastructure. D.P.U. 13-182, at 3. Among other Department policies, the Department investigated how electric distribution company involvement in EV charging could help facilitate and accommodate widespread adoption of EVs, and the Department established a standard of review for proposals related to EV charging infrastructure. D.P.U. 13-182-A at 13; D.P.U. 13-182, at 4.

On January 20, 2017, National Grid filed a petition with the Department pursuant to G.L. c. 164, §§ 76 and 94, for approval of the first phase of its EV market development program ("Phase I EV Program") and a tariff to recover the EV Program's costs, M.D.P.U. No. 1334. D.P.U. 17-13, at 1. On September 10, 2018, the Department approved National Grid's Phase I EV Program with modifications. D.P.U. 17-13, at 62.

---

[169] (https://www.mor-ev.org/program-statistics)

B. Company Proposal

1. Introduction

National Grid proposes to implement a second phase of its EV market development program ("Phase II EV Program"), with a total estimated cost of $166.5 million (Exh. NG-RS-1, at 2, 66). There are five components to the Company's proposal: (1) an EV charging program; (2) a fleet advisory services plan; (3) a marketing plan; (4) an evaluation plan; and (5) a research and development ("R&D") plan (Exh. NG-RS-1, at 3). The Company states that the goal of the Phase II EV Program is "to help the Commonwealth be on a trajectory to reach the necessary rate of transportation electrification in 2030 and 2040 to achieve the Commonwealth's public policy target of reducing GHG emissions to 80 percent below 1990 levels economy-wide by 2050" (Exh. NG-RS-1, at 4).

According to National Grid, the Phase II EV Program is more comprehensive than the Phase I EV Program, e.g., the Phase II EV Program includes EV charging stations for single family homes, fleet advisory services, and Company-owned EVSE (Exh. NG-RS-1, at 8-9). In addition, National Grid states that the Phase I EV Program was aimed at addressing light-duty vehicles, while the Phase II EV Program will target medium- and heavy-duty vehicles, as well as light-duty vehicles (Exh. NG-RS-1, at 10). The particular components of the Company's proposal are summarized below.[170]

---

[170] The Department addresses proposed PIMs and scorecard metrics related to the Phase II EV Program in Section II.C., above.

2. Phase II EV Program

a. EV Charging Program

The Company proposes to deploy an additional 17,700 level 2 ports, which are comprised of 9,000 level 2 residential ports, 8,400 non-residential level 2 ports, and 300 direct current fast charging ("DCFC") ports (Exh. NG-RS-1, at 11).[171],[172] With regard to the 8,400 non-residential level 2 ports, 4,000 ports would be placed around multi-unit dwellings and public parking areas; 3,800 ports would be situated around places of work, government offices, and private fleets; and 600 ports would be reserved for "disadvantaged communities," as that term was defined in D.P.U. 17-13 (Exh. NG-RS-1, at 11).[173] For the proposed deployment of 300 DCFC ports, 160 ports would be placed around retails areas, 40 ports would be deployed on or near highways, and the remaining 100 ports would be situated near public transit and facilities that house school buses (Exh. NG-RS-1, at 11).

---

171 Level 2 chargers rely on a 240-volt connection and are capable of fully charging most existing EVs in approximately eight hours or less depending on battery capacity. D.P.U. 17-05, at 472 n.234. DCFC chargers use direct current and are the fastest method for charging an EV. D.P.U. 17-05, at 472 n.233.

172 As part of the Phase I EV Program, National Grid expects to deploy non-residential EVSE at 140 sites, consisting of 1,200 level 2 and 80 DCFC ports (Exh. NG-RS-1, at 9).

173 For the site to qualify as a location in a disadvantaged community, the site must be located within the boundary of a population meeting two or more Massachusetts environmental justice criteria: (1) annual median household income is equal to or less than 65 percent of the statewide median ($62,072 in 2010); (2) 25 percent or more of the residents identify as minority; or (3) 25 percent or more of households have no one over the age of 14 who speaks English only or very well - Limited English Proficiency. D.P.U. 17-13, at 24-25, 30.

The Company proposes to offer two ownership models to its non-residential customers: (1) a "customer-owned" model, where the site host purchases and manages the EVSE; and (2) a "company-owned" model, where the Company owns and operates the EVSE (Exh. NG-RS-1, at 31).[174] Furthermore, the Company proposes to construct and own all customer site infrastructure (Exhs. NG-RS-1, at 32, 40; DPU-NG 17-6).[175] The total estimated cost of the EV charging program component is $153.3 million (Exh. NG-RS-2). In addition to the EV charging infrastructure costs, this total cost estimate includes two types of rebate incentives that are explained below.

i. Level 2 and DCFC EVSE Rebates

For its residential customers, the Company proposes to provide rebates to promote the installation of level 2 EVSE in single-family homes within its service territory. Specifically, National Grid proposes to offer a $1,000 rebate to defray the cost of level 2 EV chargers for residential customers (Exh. NG-RS-1, at 28).[176] For its non-residential customer-owned level 2 EVSE, the Company proposes to offer rebates of 75 percent for multi-unit dwellings; 50 percent for public parking areas, workplaces, and government or private fleets; and

---

[174] To encourage third parties to own and operate the EVSE, the Company proposes to limit the number of company-owned sites to 50 percent of all ports for non-residential customers, with the exception of level 2 EVSE in workplaces (Exhs. NG-RS-1, at 32, 40; DPU-NG 17-6).

[175] Customer site infrastructure includes the panel and conductor (Exh. NG-RS-1, at 12). In the Phase I EV Program, the customers construct and own this infrastructure with a rebate incentive from the Company (Exh. NG-RS-1, at 12).

[176] The Company seeks the ability to adjust the rebate in response to market trends (Exh. NG-RS-1, at 28).

100 percent for disadvantaged communities (Exh. NG-RS-1, at 48).[177] For its non-residential DCFC customers, the Company proposes to provide a rebate of 50 percent for the purchase of DCFC EVSE to public transit agencies and public school bus site hosts (Exh. NG-RS-1, at 35, 48). The estimated costs of these rebates are $9 million for residential level 2 EVSE rebates and $18.8 million for non-residential level 2 and DCFC EVSE rebates (Exh. NG-RS-1, at 28, 48).

ii. Residential Off-Peak Charging Rebates and DCFC Demand Charge Discounts

To incentivize off-peak EV charging by residential customers, National Grid proposes to offer a rebate for every kWh used for EV charging during off-peak hours (i.e., 9:00 p.m. to 1:00 p.m.) through its off-peak charging rebate program (Exh. NG-RS-1, at 27).[178] From June through September, the rebate would be five cents per kWh; from October through May, the rebate would be three cents per kWh (Exh. NG-RS-1, at 27).[179] The Company also would use customer charging time and charging session information gathered through this

---

177 To qualify for the 100-percent rebate, disadvantaged community customers must live within the boundary of a population meeting two or more of the Environmental Justice Community criteria outlined in footnote 173, above (Exh. NG-RS-1, at 32-33).

178 The Company states that customers may choose to opt out of this program (Exh. NG-RS-1, at 26). In addition, customers with existing level 2 chargers would be able to sign up for the program (Exh. NG-RS-1, at 27). The Company also states that it will work with automobile manufacturers to qualify monitoring technologies so that customers without level 2 chargers could potentially participate in the program (Exh. NG-RS-1, at 27).

179 The Company requests flexibility to change the rebate value per kWh as necessary during this program to achieve program goals (Exh. NG-RS-1, at 27).

program to inform future rate design or other offerings (Exh. NG-RS-1, at 26). The cost of the residential off-peak charging rebate program is estimated to be $5.6 million (Exh. NG-RS-2).

In addition, the Company proposes a time-limited discount on electric bills for dedicated DCFC electric accounts that are in a G-2 or G-3 rate class (Exh. NG-RS-1, at 35, 37). This discount would be equal to the distribution demand charge on the customer's DCFC account (Exh. NG-RS-1, at 36). The discount will decline after the first three years of billing, to 67 percent of the customer's distribution demand charge in year four, and 33 percent of the customer's distribution demand in year five (Exh. NG-RS-1, at 36). The Company intends to cap program spending for the demand charge discount at $1.2 million annually (Exh. NG-RS-1, at 37).

b. Fleet Advisory Services Plan

National Grid proposes to offer an advisory service to support the electrification of its customers' motor vehicles fleets (Exh. NG-RS-1, at 50). Through a combination of internal and third-party expertise, the Company would conduct fleet electrification studies for a total of 100 fleet operators in its service territory and require a partial payment for these services from the customer (Exh. NG-RS-1, at 50-52). According to the Company, these studies will assist these customers in making informed decisions about their future fleet operations and connect customers with fleet electrification vendors (Exh. NG-RS-1, at 51). The Company states that it will prioritize government fleets for this service (Exh. NG-RS-1, at 51). The

Company's estimated cost for the fleet advisory services plan is \$2.2 million (Exhs. NG-RS-1, at 52; NG-RS-8).

c. Marketing Plan

National Grid proposes to recover the costs of a marketing plan to promote the Phase II EV Program to EV charging and fleet advisory services customers (Exh. NG-RS-1, at 3, 53-56). The Company states that the marketing plan is essential to deployment of charging infrastructure across the Commonwealth (Exh. NG-RS-1, at 54). National Grid states that it currently communicates with customers through various methods (e.g., bills, home energy reports, email, social media, billboards, print, and radio media) and it leveraged these capabilities in developing this marketing plan to assist customers on the convenience and cost of charging an EV by (1) identifying the availability and convenience of charging stations, (2) providing information on proposed EV rate plans and installations for both at-home and public charging, and (3) providing information about newer charging technologies that greatly reduce EV charging time (Exh. NG-RS-1, at 54). Further, National Grid states that it will work with an advertising agency and partners to develop certain campaigns as part of its marketing plan (Exh. NG-RS-1, at 55-56). The cost estimate for the marketing plan is \$3.5 million and includes costs for staff and marketing of (1) an off-peak charging rebate program, (2) a charging demonstration program, (3) a discount pilot for DCFC accounts, and (4) customer fleet advisory services (Exhs. NG-RS-1, at 56; NG-RS-9).

d. Evaluation Plan

National Grid proposes an evaluation plan that includes certain activities such as (1) periodic surveys of a broad sample of residential customers, (2) pre- and post-surveys of residents and site host employees, (3) surveys or interviews of participating and non-participating sites, and (4) collection and analysis of program data (Exh. NG-RS-1, at 58). National Grid states it plans to hire an independent evaluation expert to complete this work and may propose additional activities once this expert has been contracted (Exh. NG-RS-1, at 58). National Grid asserts that the proposed evaluation plan is a continuation of and expansion upon the Phase I EV Program evaluation plan and evaluates certain new elements of the Phase II EV Program (Exh. NG-RS-1, at 58).[180] The Company states that the goals of the proposed evaluation plan are to quantify the incremental effects of the Phase II EV Program on EV adoption, customers, and charging infrastructure (Exh. NG-RS-1, at 57). The proposed evaluation plan will focus on (1) average infrastructure costs, (2) utilization levels and patterns of charging stations, (3) development of load shapes to assess the relationship between EV charging and load management efforts, (4) effects of program elements on peak demand, (5) impacts on GHG emissions, (6) benefits and costs related to interconnection, and (7) impacts on the distribution system from EV

[180] According to the Company, elements that will be continued include assessment of factors influencing site host participation; trends in attitudes, awareness, and behaviors of individuals frequenting site host locations; and similar factors amongst the broader customer base (Exh. NG-RS-1, at 58). The Company notes that proposed evaluation will expand to encompass the wider range of program features proposed in the Phase II EV Program, such as the off-peak charging rebate offering, DCFC demand charge discount, fleet services, and new R&D activities (Exh. NG-RS-1, at 58).

charging (Exh. NG-RS-1, at 57). National Grid estimates the costs of the evaluation plan to be $2.5 million (Exhs. NG-RS-1, at 59; NG-RS-10).

e. Research and Development Plan

The Company proposes to recover, through the Phase II EV Program, the costs of an R&D plan to address barriers to electric transportation utilization, assess impacts on the distribution system from electric transportation adoption, and accelerate utilization of EV charging stations (Exh. NG-RS-1, at 60). National Grid states that this R&D plan builds upon and complements the Phase I EV Program by demonstrating future-focused customer solutions and services (Exh. NG-RS-1, at 60). National Grid's R&D Plan has three components: (1) Category 1A, which will demonstrate the economic viability of diesel bus electrification (e.g., municipal and school buses); (2) Category 1B, which will solicit solutions from third parties to increase electric transportation infrastructure and increase equitable access to EVs in disadvantaged communities; and (3) Category 2, which will research the economic, environmental, grid, and customer benefits of co-locating DCFC charging stations with third- party deployed energy storage systems and solar facilities (Exh. NG-RS-1 at 61-63). The Company states that the third part of the R&D plan (i.e., Category 2), is expected to provide feedback to assist in developing next steps for the DCFC demand charge discount (Exh. NG-RS-1, at 64). The Company estimates that the cost of the R&D plan will be $5 million (Exhs. NG-RS-1, at 65; NG-RS-11).

f. Cost Recovery and Bill Impacts

The Company proposes to recover the costs associated with the Phase II EV Program by revising the existing, conceptual EV tariff and renaming it "electric vehicle program provision" (Exh. NG-RS-1, at 70). Further, National Grid proposes to create a new section within the electric vehicle program provision that is dedicated exclusively to the Phase II EV Program (Exh. NG-RS-1, at 71). While the Company intends to track Phase I EV Program and Phase II EV Program costs separately, the costs would be combined and identified as one separate line item on customers' bills (Exh. NG-RS-1, at 71). The Company also proposes an annual reconciliation process, in accordance with the protocol developed under the Phase I EV Program (Exh. NG-RS-1, at 72). Further, the Company developed an illustrative bill impact analysis for residential customers (Exhs. NG-RS-1, at 72; NG-RS-16). The Company estimates that, over the first five years of the Phase II EV Program, a residential customer using 600 kWh would experience a monthly bill increase of $0.37 in year one, $0.19 in year two, $0.16 in year three, $0.25 in year four, and $0.22 in year five (Exhs. NG-RS-1, at 72; NG-RS-16).

C. Position of the Parties

1. Attorney General

The Attorney General states that she strongly supports efforts to increase EV adoption and the availability of EV charging in the Commonwealth (Attorney General Brief at 175). Nonetheless, the Attorney General maintains that National Grid's Phase II EV Program should take into account what she contends is the lack of progress on the Company's Phase I

EV Program, as well as the Department's previous Orders on EV charging programs (Attorney General Brief at 176). Specifically, the Attorney General asserts that the Department should defer review and implementation of the Phase II EV Program until after at least one full year of Phase I EV Program data is available, which she claims is 2020, at the earliest (Attorney General Brief at 176, 180, citing Exh. AG-EAB at 10-13).[181] The Attorney General maintains that approving the Phase II EV Program without first analyzing the Phase I EV Program is contrary to the public interest and Department precedent (Attorney General Brief at 177 & n.93, citing D.P.U. 17-13, at 37-38).

The Attorney General recommends that if the Department approves any of the Phase II EV Program, it should approve only a limited number of new or high priority programs, such as the public transit and school bus segment, and impose a cap of $12 million (Attorney General Brief at 181, citing Exhs. AG-EAB at 11-12; DPU-AG 3-1). The Attorney General asserts that if the Department approves a budget that exceeds $12 million, it should (1) reduce the Company's proposed market share in particular segments, (2) adopt the Attorney General's updated prioritization schedule and reduce or eliminate lower priority and redundant Phase II EV Program elements, and (3) reject the Company's proposal to own EVSE (Attorney General Brief at 181).

Regarding the first recommendation, the Attorney General takes issue with the Company's proposed market share of 33 percent in the following segments: (1) level 2

181 The Attorney General notes that the Company expects to file its first annual report of Phase I by the end of 2019 (Attorney General Brief at 179, citing Tr. 1, at 110).

chargers in multi-unit dwellings, public parking areas, and workplaces; and (2) DCFCs in highway and retail locations (Attorney General Brief at 182-183). Specifically, the Attorney General maintains that the market share of 33 percent in these segments is arbitrary and could lead to significant over-investment in EVSE relative to true market needs (Attorney General Brief at 182-183, citing Exh. AG-EAB at 22-23). In addition, the Attorney General asserts that the Company's proposed market share has the potential to crowd out competitive market investments and, thus, the Department should reduce National Grid's market share to ten percent of these segments (Attorney General Brief at 181-182, citing Exhs. NG-RS-1, at 23; AG-EAB at 22).

Regarding the recommendation above, the Attorney General asserts that in D.P.U. 17-13, at 30, the Department directed National Grid to prioritize the selection of level 2 charging sites to focus on publicly accessible areas (Attorney General Brief at 184). The Attorney General agrees with the sentiment behind the prioritization list, but offered some modifications to better reflect the Company's Phase II offerings and align them with the public interest (Attorney General Brief at 184, citing Exh. AG-EAB at 14-15). The Attorney General claims that the Company's Phase II EV Program budget does not reflect the Department's prioritization directives or the Attorney General's recommended updates (Attorney General Brief at 184, citing Exhs. AG 18-4; AG-EAB at 15). Therefore, the Attorney General recommends that the Department should adopt the Attorney General's prioritization recommendations to ensure that the benefits of the Company's Phase II EV Program accrue to a broad cross-section of the public (Attorney General Brief at 184).

In addition, the Attorney General maintains that the lower prioritization items should either be decreased or eliminated (Attorney General Brief at 185). In particular, the Attorney General focuses on the Company's level 2 residential program, which consists of EV charger rebates for residential level 2 chargers and an off-peak charging rebate program (Attorney General Brief at 185). The Attorney General asserts that the Company's proposal could lead to a regressive cross-subsidy by providing rebates to high-income customers at the expense of all customers, including low-income customers (Attorney General Brief at 185, citing Exh. AG-EAB at 24). As a remedy, the Attorney General recommends targeting the level 2 residential program to low-income customers who may face additional barriers to EV adoption (Attorney General Brief at 185, citing Exh. AG-EAB at 24). Alternatively, the Attorney General asserts that the Company should guarantee continued participation in the off-peak charging program (Attorney General Brief at 185).

The Attorney General also recommends changes to the fleet advisory services proposal (Attorney General Brief at 185). The Attorney General notes that the Company proposes to provide free fleet electrification studies for 100 fleet operators in its service territory (Attorney General Brief at 185). The Attorney General expresses concern that offering a free service will make it difficult to evaluate whether fleet owners would otherwise seek out such service (Attorney General Brief at 185). To address this concern and reduce the costs, the Attorney General maintains that the Company should require participating customers to contribute at least 50 percent of the costs of the fleet advisory service (Attorney General Brief at 186, citing Exhs. AG-EAB at 26; DPU-NG 17-16). The Attorney General further recommends that the Department reject the Company's proposed R&D and marketing budgets for the Phase II EV Program on the basis that the Phase I EV Program already provides funding for these activities and that the Company has not justified additional spending at this time (Attorney General Brief at 186, citing Exh. AG-EAB at 26).

Regarding the third recommendation above, the Attorney General notes that National Grid proposes to own up to 50 percent of the EV chargers in almost every level 2 and DCFC category (Attorney General Brief at 186, citing Exh. NG-RS-1, at 31). The Attorney General maintains that National Grid has failed to demonstrate that (1) its ownership of EVSE meets a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV market and (2) Company ownership of EVSE does not hinder the competitive EV charging market (Attorney General Brief at 186-187). The Attorney General also expresses concern that the company-owned option may prove to be significantly more expensive than the customer-owned option (Attorney General Brief at 187). In addition, the Attorney General asserts that the Department previously determined that for the Phase I EV Program, the Company would not own or operate any EVSE or participate in the competitive EVSE market (Attorney General Brief at 187, citing D.P.U. 17-13, at 18).

In addition to the foregoing, the Attorney General also argues that the Company's rate options of a residential off-peak charging rebate and a demand charge discount for certain DCFC chargers are too limited in scope and do not "do enough" to incentivize off-peak charging of EVs (Attorney General Brief at 189). Thus, the Attorney General recommends that the off-peak charging rebate should be extended to non-residential customers and that the peak time window be changed to 2 p.m. to 7 p.m. (Attorney General Brief at 190, citing Exh. AG-EAB at 34-36).[182] The Attorney General also recommends that the Department direct National Grid to develop a comprehensive set of EV time-of-use rates by a date certain (Attorney General Brief at 190, citing Exh. AG-EAB at 34-36). Further, regarding the demand charge discount, the Attorney General recommends that the Department adopt one of the following options: (1) apply the discount only to the highest level of demand occurring during off-peak hours or (2) require that the DCFC chargers demonstrate that their level of utilization surpasses a certain threshold to qualify for the discount (Attorney General Brief at 190, citing Exh. AG-EAB at 35).

Finally, the Attorney General asserts that the Department should proceed with a statewide EV stakeholder process consistent with the process contemplated in docket D.P.U. 17-13 (Attorney General Brief at 190-191, citing D.P.U. 17-13, at 29, 8). The Attorney General maintains that statewide coordination is necessary because (1) EV loads are not stationary and cross service territories, (2) EV chargers need to be optimally sited for all potential EV adopters, (3) resources need to be used efficiently in deployment of EV infrastructure, and (4) more geographic aspects need to be considered (Attorney General Brief at 191). The Attorney General asserts that, in the interim, the Department should

[182] The Attorney General states that, contrary to the Company's contention that no analysis was provided, she provided an analysis of ISO-NE load and pricing data used to develop the proposed peak period of 2 p.m. to 7 p.m., (Attorney General Reply Brief at 68, citing Exh. NG-AG 2-6, Att. 1).

require the Company, in coordination with NSTAR Electric, to conduct an analysis on optimal siting for workplace charging (Attorney General Brief at 191).

2. Acadia Center

Acadia Center states that EV infrastructure is an important investment in Massachusetts' clean energy future; however, Acadia Center recommends that the Department defer the majority of the Phase II EV Program and only approve certain components of the program (Acadia Center Brief at 16-17). In particular, Acadia Center argues that the Department could approve aspects of the Phase II EV Program where the absence of competitively supplied EVSE is likely due to market failure, such as level 2 EVSE for public parking areas, disadvantaged communities, and government fleets, as well as DCFC investment for public transit and school buses (Acadia Center Brief at 19). Acadia Center also claims that approving DCFC for public transit and school buses could ease transportation concerns and reduce diesel pollution (Acadia Center Brief at 19-20).

Acadia Center also supports approval of the Company's proposed off-peak charging rebate program (Acadia Center Brief at 20). Acadia Center states that this part of the program is necessary to compile data on charging behavior in advance of a statewide EV proceeding (Acadia Center Brief at 20). Acadia Center asserts that as rates of EV penetration increase the Department must simultaneously encourage off-peak charging and minimize the risk of increasing costs to all customers (Acadia Center Brief at 20). Acadia Center also recommends that the Department require the Company to commit to developing

EV time-of-use rates as part of the statewide coordination process (Acadia Center Brief at 20).

In addition to the foregoing, Acadia Center argues that Company ownership of EVSE is inappropriate and inconsistent with the Department's criteria for evaluating utility investment in EV infrastructure (Acadia Center Brief at 20-21, citing D.P.U. 13-182-A at 13). Acadia Center also maintains that there is no evidence from the Phase I EV Program that EVSE ownership and operation is a barrier for site hosts enrolling in the program (Acadia Center Brief at 21, citing Exh. CP-PJC-1, at 7). According to Acadia Center, Company ownership interferes with the competitive market and should only be allowed in the event a market failure exists or it can be demonstrated that such ownership does not interfere with the competitive market (Acadia Center Brief at 21).

Finally, Acadia Center recommends that the Department commence a statewide coordinated EV proceeding to determine how investment in utility EV infrastructure fits within the Commonwealth's clean energy and GHG reduction strategies (Acadia Center Brief at 17-19).[183] As part of this proceeding, Acadia Center asserts that statewide metrics and time-of-use rate structures could be created and the Department could ensure that utilities are buying the right equipment, locating it in the best places, and providing real benefits to customers at the lowest possible cost (Acadia Center Brief at 17).

---

183 Acadia Center notes that National Grid's proposed Phase II EV Program would run concurrently with at least five other EV programs in Massachusetts all administered by different agencies, including DOER and the Department of Environmental Protection (Acadia Center Brief at 17-18).

3. API

API argues that because the Phase I EV Program has not yet been evaluated, the Phase II EV Program is premature and should be rejected (API Brief at 19). API maintains that in approving the Phase I EV Program, the Department noted the importance of program evaluation (API Brief at 19; API Reply Brief at 4). API argues that National Grid has offered no evaluation of the Phase I EV Program, as required by the Department, nor has the Company selected a contractor to perform the evaluation of the Phase I EV Program (API Brief at 20, citing Exhs. AG-EAB at 9; AG 18-2; Tr. 1, at 23, 74-75). API further claims that the Company has not yet installed any EVSE under its Phase I EV Program (API Brief at 20-21, citing Exh. AG 18-3).

API also argues that the Department should reject National Grid's Phase II EV Program because it is an "ill-advised" approach to meeting the Commonwealth's 2050 environmental goals (API Brief at 8). Specifically, API maintains that the Company overestimates the number of EVs and charging ports necessary by 2025 and refers to 2030 and 2040 carbon reduction goals that are not actually established by the legislature (API Brief at 8, citing Exh. NG-RS-1, at 4). In particular, API contends that in the Phase I EV proceeding, the Company estimated the need for 300,000 ZEV vehicles by 2025, but that in the instant proceeding, the number has increased by 82 percent to 546,464 (API Brief at 9, citing Exh. NG-RS-13; Company Brief at 34). API asserts that the Company's EV calculations fail to reflect EV statistics projecting that the EV adoption rate will slow significantly between 2020 and 2024 (API Brief at 9-10).

In addition, API asserts that overbuilding in the presence of rapidly changing technology will lead to stranded assets, where infrastructure is installed too early and becomes obsolete in light of rapidly changing technology (API Brief at 10). Thus, according to API, there will not be enough EVs to support the infrastructure (API Brief at 10; API Reply Brief at 7). API maintains that overbuilding will also lead National Grid to own a much larger percentage share of the market than intended (API Brief at 10; API Reply Brief at 7).

API is also concerned that the lack of coordination in the expansion of EVSE could have unintended adverse effects on GHG emissions (API Brief at 11, citing Exh. FSCS-JDM-1, at 20-23). Specifically, API maintains that because the majority of the Phase II EV Program funds are dedicated to developing public charging stations, on-peak charging is far more likely to occur (API Brief at 12, citing Exh. FSCS-JDM-1, at 22). API argues that this increase in on-peak charging would likely be met by deploying additional peaking units and may not result in a net reduction in emissions (API Brief at 11, citing Exh. FSCS-JDM-1, at 20-23).

In addition, API argues that the "sheer magnitude" of the Phase II EV Program in terms of costs warrants Department scrutiny (API Brief at 12). API maintains that in comparison to proposals in other states, the National Grid proposal would be the most expensive EV program in the United States (API Brief at 13; API Reply Brief at 2). Further, API contends that the Phase II EV Program results in lower-income ratepayers subsidizing higher-income EV adopters (API Brief at 16; API Reply Brief at 8-9). Thus, API argues that the Department should not approve a program that favors a small group of upper income household who use EVs at the expense of lower income households (API Brief at 18; API Reply Brief at 8-9).

API also points out that in D.P.U. 17-13, at 18, the Company stated that it would not own or operate any EVSE and that it did not intend to participate in the competitive market (API Brief at 22). API alleges that allowing the Company to own EVSE would put market participants at a competitive disadvantage given that the Company bears no risk of capital and will be made whole through ratepayer cost recovery (API Brief at 23). Moreover, API expresses concern that by approving the Phase II EV Program the Department will be declaring EVs the winner at the expense of other alternative fuel options, such as hydrogen cell and zero- or low-emission vehicles (API Brief at 25). As an alternative to only promoting a single fuel technology, API recommends that the Department prioritize broader energy solutions for the transportation sector (API Brief at 26; API Reply Brief at 6). Finally, API argues that National Grid's proposal for Company-owned EVSE is a good deal for shareholders, but a bad deal for ratepayers because it is entirely ratepayer funded, with no risk to private capital or to shareholders (API Brief at 26).

4. ChargePoint

ChargePoint supports approval of the Company's Phase II EV Program (ChargePoint Brief at 4). ChargePoint maintains that the Company's proposal meets the Department's requirements for approval of a program promoting ZEV adoption (ChargePoint Brief at 4; ChargePoint Reply Brief at 1). ChargePoint also asserts that the Phase II EV Program is consistent with the Commonwealth's ZEV target to get 300,000 vehicles on the road by 2025, as well as the Commonwealth's targets for reducing GHG emissions under the Global Warming Solutions Act (ChargePoint Brief at 4, citing Exhs. NG-RS-1, at 4 & n.1; NG-RS-Rebuttal-1, at 7-8). ChargePoint also argues that the Company's proposal is in the public interest because it includes a significant focus on residential EV charging and would help to ensure that charging takes place at times that are beneficial to the grid through customer incentives (ChargePoint Brief at 5, citing Exh. NG-RS-1 at 24–30).

Further, ChargePoint argues that the program meets a need because it advances EVs in the Commonwealth (ChargePoint Brief at 5). ChargePoint states that despite growth of the competitive EVSE market, barriers still exist to EVSE deployment, which is largely due to upfront costs (ChargePoint Brief at 5, citing Exh. CP-PJC-1, at 5-6, 9). Therefore, ChargePoint asserts that the Company is best positioned to evaluate the most cost-effective way to supply a site (ChargePoint Brief at 5-6). ChargePoint further contends that although the Phase I EV Program was approved, many sectors were left unaddressed (e.g., residential level 2 EVSE, electrification of heavy-duty vehicles) and that the Phase II EV Program addresses those sectors (ChargePoint Brief at 6).

ChargePoint also asserts that National Grid is well positioned to raise customer awareness through its marketing plan and that the Company would be an effective partner to EVSE providers by sharing its offerings and marketing to customers (ChargePoint Brief at 6, citing Exh. CP-PJC-1, at 11). ChargePoint asserts, however, that any marketing program developed by National Grid should seek active participation of all interested EVSE providers, and the Company should not pick preferred providers for providing marketing materials, but should use vendor-neutral materials or make use of all existing marketing materials for EVSE and network services that meet the Company's technical and informational requirements (ChargePoint Brief at 6, citing Exh. CP-PJC-1, at 9, 12).

Moreover, ChargePoint argues that the EV program will not hinder the development of the competitive EV market because the Company will offer an option for Company-owned and -maintained EVSE and customer-owned and -maintained EVSE (ChargePoint Brief at 7). ChargePoint also maintains that the site hosts should remain in control of pricing charged to drivers (ChargePoint Brief at 9).

For all of these reasons, ChargePoint supports approval of the Company's Phase II EV Program. ChargePoint recommends, however, that if the Phase II EV Program is approved, the Department should explicitly require, regardless of whether the EVSE is Company-owned or customer-owned, the following program design conditions: (1) site hosts will have choice in both EV charging equipment and network services; and (2) site hosts will ultimately determine what, if any, price is determined for EV charging services (ChargePoint Reply Brief at 2-3).

5. Clean Energy Parties

The Clean Energy Parties assert that the Company's Phase II EV Program meets the standard of review for utility EV infrastructure investment, as established in D.P.U. 13-182-A (Clean Energy Parties Brief at 14-18; Clean Energy Parties Reply Brief at 5-11). The Clean Energy Parties argue that there is still a need for increasing EV charging infrastructure and that barriers exist to such deployment, since site hosts need to make significant investments but may not directly benefit from such investments (Clean Energy Parties Brief at 19). Further, the Clean Energy Parties disagree with the FSCS Coalition that a traditional cost-benefit analysis is required to support the Phase II EV Program (Clean Energy Parties Reply Brief at 6).

Regarding some of the specifics of the Company's proposal, the Clean Energy Parties argue that some utility ownership of EVSE may be necessary given that only one of 200 applications received as part of the Phase I EV Program is for DCFC EVSE (Clean Energy Parties Brief at 19-20).[184] Further, the Clean Energy Parties argue that, because of the lack of EV infrastructure investment at multi-unit dwellings and in disadvantaged communities, utility involvement in the competitive market would not stifle such a market (Clean Energy Parties Brief at 20-21). The Clean Energy Parties reject any notion that the Phase II EV Program could lead to overbuilding of EV infrastructure, stranded assets, and obsolete EVSE, arguing instead that the Company's proposal only targets a small fraction of the Commonwealth's EV charging requirements (Clean Energy Parties Reply Brief at 8).

While in support of the Company's proposal, the Clean Energy Parties recommend that the Phase II EV Program include new time-of-use rates and EV load management strategies for non-residential charging (Clean Energy Parties Brief at 22). Moreover, the Clean Energy Parties argue that the off-peak charging rebate does not include all the benefits

---

[184] The Clean Energy Parties disagrees with what they claim is the Attorney General's argument that D.P.U. 17-13 discouraged utility EVSE ownership (Clean Energy Parties Reply Brief at 11).

(e.g., avoided transmission and distribution costs, avoided Global Warming Solutions Act compliance costs) that off-peak charging generates and should, therefore, be augmented in subsequent measures to capture these benefits (Clean Energy Parties Brief at 22-23).

Finally, the Clean Energy Parties argue that it is not necessary for the Phase I EV Program to be completed before the instant proposal can be approved, but rather additional data from Phase I can inform the Phase II EV Program on an ongoing basis (Clean Energy Parties Reply Brief at 13). According to the Clean Energy Parties, any delay in implementing the new elements of the Phase II EV Program (e.g., off-peak charging rebate, DCFC demand charge discount, a utility-ownership option for certain market segments, Fleet Advisory Services plan) will undermine the ability to carry out the Commonwealth's Global Warming Solutions Act goals (Clean Energy Parties Reply Brief at 12-13). The Clean Energy Parties also contend that a generic EV investigation should not interfere with approval of the Phase II EV Program and should not be a basis for deferring the Phase II EV Program (Clean Energy Parties Reply Brief at 15).

6. Conservation Law Foundation

CLF supports the Company's proposed Phase II EV Program with certain modifications (CLF Brief at 10). CLF argues that the Phase II EV Program meets a need not likely to be met by the competitive market and that it addresses barriers to EV adoption that the competitive market alone has not overcome (CLF Brief at 10-13). Further, CLF contends that implementation of the Phase II EV Program will alleviate many drivers' concerns that EV charging availability is insufficient and businesses' worries that if they invest in EV infrastructure there may not be enough EV charging consumers (CLF Brief at 13). Moreover, CLF argues that the Phase II EV Program will assist in facilitating significant growth in a short amount of time across all market segments because the proposal strategically targets many market segments and because the Company will partner with site hosts and EVSE providers to jumpstart the EV market (CLF Brief at 14-15).

CLF also argues that the Phase II EV Program will not hinder the development of the competitive market because the proposal facilitates the development and expansion of the private market by "creating opportunities where opportunities for EV providers did not exist before" (CLF Brief at 15). CLF further alleges that the Phase II EV Program does not limit private firms from marketing to site hosts and compete amongst each other (CLF Brief at 15).

CLF recommends certain modifications to the Phase II EV Program (CLF Brief at 15). First, CLF argues that the proposed rate for the off-peak charging rebate program should reflect all the benefits (e.g., avoided transmission and distribution costs and avoided Global Warming Solutions Act compliance costs) that EVs provide and that the rate could be augmented at no cost to ratepayers (CLF Brief at 19-21; CLF Reply Brief at 6). Second, CLF recommends that the Department should require the Company to design EV time-of-use rates by a date certain to create a permanent solution that encourages optimal charging times and services to the grid (CLF Brief at 21; CLF Reply Brief at 6).

CLF also claims that a larger commitment to environmental justice communities is needed when deploying EV charging infrastructure (CLF Brief at 22; CLF Reply Brief at 6).

Thus, CLF argues that the Company should commit to a minimum investment in environmental justice communities to properly advance the public interest, and CLF contends that the Department should direct National Grid to establish a ten percent floor on its investment in communities that meet at least one of the state criteria for environmental justice communities (CLF Brief at 23-24; CLF Reply Brief at 6). In addition, CLF asserts that the Department should require National Grid to closely coordinate its DCFC offering with its fleet advisory service plan and its R&D plan Category 1A to better address the needs of environmental justice communities and disadvantaged communities, neither of which may have the resources to invest in fleet electrification (CLF Brief at 25; CLF Reply Brief at 7). Finally, CLF further recommends that the Department require the Company to complement its deployment of 300 level 2 EVSE across environmental justice populations with a program that facilitates shared mobility services such as electric ride-hailing and car sharing (CLF Brief at 25-26; CLF Reply Brief at 7).

7. DOER

As an initial matter, DOER opposes any additional funding for Phase I EV Program components that are being expanded in the proposed Phase II EV Program (DOER Brief at 11-12). Moreover, DOER asserts that the Department should require the Company to file evaluation reports for both programs concurrently, so that the Department can evaluate the results of both Phase I and Phase II EV Programs in a single proceeding (DOER Brief at 12, 17).[185] DOER also recommends that the Department require that the Company to consult with DOER on the scope and selection of a third-party consultant to evaluate the EV programs (DOER Reply Brief at 16).

Regarding the particulars of the Company's proposal, DOER recommends that the Department only approve certain components of the Phase II EV Program, given that no results from the Phase I EV Program have been analyzed (DOER Brief at 11). DOER argues that approving only the following new program components would avoid delay in EV advancement: (1) the residential EVSE rebate and off-peak charging rebate; (2) DCFC EVSE for public transit and school bus sites; (3) the demand charge discount; (4) the fleet advisory services plan; (5) modified marketing and evaluation plans; and (6) the R&D plan (DOER Brief at 12). DOER claims that approval of the off-peak charging rebate program will incent off-peak charging, put downward pressure on electricity rates, and distribute costs across greater electric sales, all of which will provide benefits to all ratepayers (DOER Brief at 14). DOER contends that the DCFC EVSE for public transit and school bus sites should be approved because these are new sites that were not addressed in the Phase I EV Program (DOER Brief at 15). DOER supports approval of the DCFC demand charge discount and extending it to existing customers because it would reduce operating costs of DCFC EVSE

---

185 DOER recommends that the Department require the Company's evaluation report to include detailed costs for all approved programs to clearly monitor the effectiveness of such measures (DOER Brief at 20). In addition, DOER recommends that the Department require the Company to consult with DOER prior to submitting each annual report to determine which parts of the program should be expanded (DOER Brief at 20).

(DOER Brief at 15). In addition, by expanding this offering to existing customers, DOER asserts it would put existing and new DCFC EVSE at a level playing field (DOER Brief at 16).

DOER also favors approval of the fleet advisory services component of the National Grid's proposal, arguing that (1) the Company is well suited in assisting these customers on optimal charging while also mitigating distribution system upgrades and (2) it is consistent with the Commonwealth's objective of transportation electrification to decrease consumption and emissions (DOER Brief at 21-22). DOER asserts that the Department should direct National Grid to report the following metrics: (1) number of fleets identified; (2) size of fleets; (3) success of implementation and how many fleets used the program; (4) expenses; (5) results of the recommendations and number of fleets recommended to be electrified; (6) reasoning for recommendations; (7) cost sharing of infrastructure costs between the utility and the fleet; and (8) market interest in providing services (DOER Brief at 22).

Further, DOER argues that the Company's marketing plan should be approved, but the spending amounts should be commensurate with approved funding for the Phase II EV programs (DOER Brief at 22). Thus, because DOER opposes the approval of proposed investments in charging stations that are already funded through the Phase I EV program, DOER asserts that the Department should reject $1.5 million in marketing plan costs related to the charging station demonstration project (DOER Brief at 23). Further, DOER argues that the Department should direct the Company to report the following information on its marketing plan implementation: (1) number of customers identified; (2) customer engagement analytics; (3) uptake by each program category; (4) unique considerations and targeting methodology by program and focus audience; and (5) content used (DOER Brief at 23).

DOER supports approval of the R&D plan and asserts that the R&D plan would serve areas where barriers exist and identify potential ways to lower the cost of EV deployment (DOER Brief at 23). Further, DOER contends that the R&D plan will provide valuable lessons and may enable a more cost effective and efficient transition to electrification (DOER Brief at 24). DOER asserts that the Department should direct the Company to report R&D plan implementation information on (1) low-income residential participation, (2) number and frequency of stakeholder meetings with low-income groups, and (3) stakeholders engaged to help with the plan implementation (DOER Brief at 24).

In addition to the foregoing, DOER supports utility ownership of EVSE, but only for those locations identified in the Phase I EV Program (DOER Brief at 18). According to DOER, limited utility ownership would provide customer choice and may further policy objectives of serving disadvantaged communities (DOER Brief at 18). Finally, DOER argues that the Department should require the Company to file evaluation reports for both programs concurrently, so that the Department can evaluate the results of both Phase I and Phase II EV Programs in a single proceeding (DOER Brief at 12, 17). DOER contends that the Company's evaluation reports should include detailed costs for all approved programs in order to effectively monitor the effectiveness of such measures (DOER Brief at 20).[186] Further, DOER asserts that the Company should consult with DOER prior to submitting each annual report to determine which parts of the program should be expanded (DOER Brief at 20).[187]

8. FSCS Coalition

The FSCS Coalition argues that the Company's proposal is premature, and it recommends that the Department defer review of the Phase II EV Program until evaluation results from the Phase I EV Program are available (FSCS Coalition Brief at 16-20; FSCS Reply Brief at 6-7). The FSCS Coalition states that a short-term delay is more effective than a rushed approval, and the Company has not proven that a short-term delay would negatively impact the Commonwealth's policy goals for achieving its GHG emissions reduction goals (FSCS Coalition Brief at 22-23).[188] Nonetheless, the FSCS Coalition does not oppose the Department's approval of certain elements of the Phase II proposal that were not included in

---

186 DOER also supports MEDA's position that the Phase II EV Program should be evaluated with targeted metrics that evaluate low-income participation in utility EV infrastructure investments, and that the Department should direct the Company to conduct targeted stakeholder input sessions including disadvantaged community organizations (DOER Reply Brief at 14-15, citing Exh. MEDA-JH at 20-21, MEDA Brief at 12-17).

187 DOER also recommends that the Department require that the Company consult with DOER on the scope and selection of a third-party consultant to evaluate the EV programs (DOER Reply Brief at 16-17).

188 The FSCS Coalition also supports an EV stakeholder process and/or generic docket to address issues requiring statewide coordination, in which all electric distribution companies could participate (FSCS Coalition Brief at 17 n.7).

Phase I and would provide valuable data that could inform future EVSE deployment (FSCS Coalition Brief at 26). For example, the FSCS Coalition supports (1) the off-peak charging rebate program and (2) the DCFC demand charge discount (FSCS Coalition Brief at 26). The FSCS Coalition also asserts that the DCFC demand charge discount should be expanded to existing customers (FSCS Coalition Brief at 26).

Despite support for some of the Company's proposal, the FSCS Coalition argues that the vast majority of the proposed Phase II EV Program is unwarranted and fails to meet the standards established in D.P.U. 13-182-A (FSCS Coalition Brief at 26-49). For example, the FSCS Coalition argues that the Phase II EV Program is not in the public interest because the Company has not demonstrated benefits for ratepayers (FSCS Coalition Brief at 26-27). In this regard, the FSCS Coalition contends that the policy benefit cost analysis provided by the Company in this proceeding is illustrative and speculative (FSCS Coalition Brief at 28). Thus, the FSCS Coalition asserts that because the Company has not provided actual data regarding impacts of the Phase I EV Program, the Department cannot be compelled to approve the proposal based on unknown projections of ratepayer benefits (FSCS Coalition Brief at 29). The FSCS Coalition argues that the Department should direct the Company to provide the following information to demonstrate that the program is in the public interest: (1) alternatives to the Phase II EV Program that would also advance the goal of increasing transportation electrification to lower GHG emissions; (2) an evaluation of the specific Phase II EV Program and its cost-effectiveness relative to alternatives; and (3) an evaluation of the Phase I EV Program and the implications for the Phase II EV Program (FSCS

Coalition Brief at 30). FSCS also argues that National Grid has not reliably established that its proposal will meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive charging market (FSCS Coalition Brief at 43-44). Further, FSCS contends that the proposed Phase II EV Program, in particular the Company's proposal to own and operate EVSE, will hinder competitive EV charging market and may negatively affect ratepayers (FSCS Coalition Brief at 44-48).

Finally, FSCS argues that if the Department approves any part of the Phase II EV Proposal, it should do so only with several modifications, including: (1) rejecting National Grid's proposal to own and operate EVSE, or limiting ownership to market segments least likely to be served by the competitive market where barriers to entry would be the highest; (2) reducing the Company's market share from 33 percent to 10 percent for level 2 chargers in multi-unit dwellings, public parking areas, and workplaces, and DCFCs in highway and retail locations; (3) extending the off-peak charging rebate to both existing and future DCFC charging stations in the Company's service territory (FSCS Coalition Brief at 51-52, citing Exhs. AG-EAB at 23 NECEC-NP-1, at 61, 63; NECEC-NP-Surrebuttal-1, at 2).

9. eMotor Werks

eMotor Werks supports approval of the Company's Phase II EV Program (eMotor Werks Brief at 4). eMotor Werks asserts that the Phase II EV Program will catalyze needed infrastructure investment in a comprehensive range of customer segments and EV charging use cases, while leaving room for other sources of public and private funding (eMotor Werks Brief at 4). eMotor Werks also maintains that the Company's proposals regarding fleet advisory services, marketing and education, evaluation, and R&D will serve the essential functions of increasing consumer awareness of EV issues and the Company's offerings (eMotor Werks Brief at 5).

With respect to the level 2 residential EVSE rebate program, eMotor Werks argues that customer EVSE ownership is appropriate for the residential segment as upfront costs are relatively low and, therefore, present a lower payback risk to customers as compared to other customer segments and charging applications (eMotor Werks Brief at 6). eMotor Werks recommends that, to increase customer awareness of different EVSE and network options the Company should (1) issue requests for qualifications to seek candidate EV service providers and (2) offer a utility-hosted webstore for eligible products from qualified service providers (eMotor Werks Brief at 6). eMotor Werks also supports the $1,000 rebate provided under the Company's residential offering, but recommends that National Grid make it explicit that customers may recoup only their actual costs up to the $1,000 rebate amount (eMotor Werks Brief at 7).

Despite its support for elements of National Grid's residential level 2 EVSE rebate program, eMotor Werks asserts that the Company's filing lacked necessary details relating to implementation of the rebate offering (eMotor Werks Brief at 7). As such, eMotor Werks argues that the Company should launch a competitive RFP and establish a framework to sign up qualified EVSE installers to serve as program administrators for the residential level 2 rebate program offering in order to manage all critical aspects of the customer experience (eMotor Werks Brief at 7-8).

eMotor Werks also is supportive of the proposed off-peak charging rebate program, but argues that the Department should require the Company to: (1) develop and roll out additional smart EV charging pilots throughout the term of the Phase II EV Program, which would inform expand smart charging offerings in the future; and (2) lower the residential off-peak charging rebate offering to $5.00 per month and use the remaining budgeted money to support rebates that go directly towards the purchase and installation of EVSE (eMotor Werks Brief at 10-11).

With regard to the non-residential sector, eMotor Werks supports the Company's proposal of utility ownership, which eMotor Werks asserts would help address barriers to and foster competition (eMotor Werks Brief at 11-12). eMotor Werks also supports the Company's construction and ownership of make-ready infrastructure (eMotor Werks Brief at 12).

With respect to charging rates at Company-owned EVSE, eMotor Werks notes some alternatives it posits could better posture National Grid to maintain its overall competitiveness for privately owned stations, while discouraging on-peak charging on the hottest days of the summer (eMotor Werks Brief at 14-15). Specifically, eMotor Werks argues that National Grid could require all utility-owned EVSE to participate in a critical peak pricing or emergency curtailment tariff that would pass through drastically elevated prices or curtailment signals to drivers for ten to 20 event days per year (eMotor Works Brief at 14).[189] eMotor Werks also asserts that the Department could benchmark publicly available charging prices of private EVSE providers operating in National Grid's service territory to ensure that the Company's rates are at or above the median rate of the competitive market (eMotor Werks Brief at 15).

Finally, eMotor Werks recommends expanding the DCFC demand charge discount to non-residential customers of level 2 EVSE (eMotor Werks Brief at 15). eMotor Werks asserts that this expansion is appropriate given that level 2 EVSE non-residential customers experience similar barriers to demand charges (eMotor Werks Brief at 15).

10. <u>Greenlots</u>

Greenlots supports approval of the proposed Phase II EV Program (Greenlots Reply Brief at 10). Greenlots maintains that the proposed Phase II EV Program will support the Commonwealth's EV public policy goals and that, without the Phase II EV Program, the Commonwealth will not be able to meet its decarbonization goals or ensure a viable and sustainable EV marketplace (Greenlots Reply Brief at 9-11).

Further, Greenlots argues that the proposed Phase II EV Program meets the Department's three pronged criteria (Greenlots Reply Brief at 9, 10-17). In particular, Greenlots contends that Company's proposal is in the public interest, as the private EV marketplace alone cannot deploy the appropriate level of education, incentives, and

---

189 Under eMotor Werks alternative, drivers would be notified of the scheduled event before initiating a charging session but would ultimately not be deterred from becoming a repeat customer from facing daily peak charging rates (eMotor Werks Brief at 14).

opportunities to help achieve the Commonwealth's EV goals (Greenlots Reply Brief at 12). Therefore, according to Greenlots, the Phase II EV Program will aid customers by increasing the information available to them about EVs and EVSE, while also making such information more accessible (Greenlots Reply Brief at 12).

In addition, Greenlots contends that the utility ownership components of the Company's proposed Phase II EV Program meets a need regarding the advancement of EVs and EV charging infrastructure in the Commonwealth in a manner not likely to be met by the competitive EV charging market (Greenlots Reply Brief at 12). Greenlots argues that barriers continue to exist in deployment of EVs and EV charging infrastructure, and that EV charging companies have not significantly deployed EVSE in disadvantaged communities, which could be best addressed through utility ownership and involvement through the proposed Phase II EV Program (Greenlots Reply Brief at 14).

Finally, Greenlots argues that the Company's proposed Phase II EV Program will not hinder the competitive EV charging market and will, in fact, help to support it (Grenlots Reply Brief at 15). According to Greenlots, utility investment in EV charging infrastructure will help spur EV deployment and encourage future private investment of charging infrastructure (Greenlots Reply Brief at 15).

11. MEDA

MEDA maintains that approval of the Phase II EV Program should be delayed until the Company conducts a broad stakeholder engagement and planning process, including identifying the needs of disadvantaged communities (MEDA Reply Brief at 8-11). MEDA argues that, if the Department chooses to approve any portion of the Phase II EV Program, the Department should do the following: (1) direct the Company to conduct targeted low-income stakeholder input sessions in its service territory, in consultation with MEDA and other organizations that serve low-income communities; (2) open a generic investigation of the type contemplated in D.P.U. 17-13 to discuss statewide issues related to EV charging infrastructure; and (3) order the establishment of a low-income transportation electrification "best practices" group to meet on an ongoing basis to help develop EV infrastructure investment policy and practices so as to deliver meaningful benefits to low-income communities (MEDA Brief at 15-19; MEDA Reply Brief at 9-11).

12. NECEC

NECEC asserts that National Grid has not met its burden under D.P.U. 13-182-A at 13 (NECEC Brief at 34). Specifically, NECEC maintains that the Company proposes to enter the emerging EV charging market using ratepayer funds, not Company funds (NECEC Brief at 34). NECEC also contends that the Company's profits depend not on the success of the charging equipment paying for itself, but rather on a regulatory formula that generates ratepayer-funded earnings regardless of whether anyone uses those charging facilities (NECEC Brief at 34, citing Exh. FSCS-JDM-Surrebuttal-1, at 4). NECEC asserts that competitive entrants into the EV charging market are unable to rely on others' money and, therefore, National Grid would have a huge competitive advantage (NECEC Brief at 35, citing Exh. FSCS-JDM-Surrebutal-1, at 4).

In addition, NECEC maintains that the active participation of intervenors in this proceeding alone contradicts the Company's claim that the competitive market cannot serve the needs of the EV market (NECEC Brief at 35). Based on these considerations, NECEC maintains that the Department should limit National Grid's participation in the EV charging market to developing make-ready infrastructure and providing customer rebates (NECEC Brief at 36, citing Exh. NECEC-NP-1, at 62).

NECEC contends that if the Department determines that sufficient evidence exists to justify Company ownership and operation of EV charging equipment, then site hosts of Company-owned EV charging equipment should be given choices in both EV charging equipment and network vendor services deployed on their property (NECEC Brief at 36-37, citing Exh. NECEC-NP-1, at 62-63). NECEC also argues that Company-owned ports should be limited to (1) ten percent of level 2 government and private fleet charging ports, (2) ten percent of level 2 disadvantaged communities charging ports, and (3) ten percent of DCFC public transit and school bus charging ports (NECEC Brief at 37, citing Exh. NECEC-NP-Surrebuttal-1, at 18).

NECEC also takes issue with the Company's proposal regarding the demand charge discount (NECEC Brief at 37). NECEC maintains that the Company intends to only offer the demand charge discount only to those systems installed under the Phase II EV Program (NECEC Brief at 37, citing Exh. NG-RS-1, at 36). According to NECEC, excluding the small number of stations installed prior to the Phase II EV Program could chill customer adoption of DCFC out of fear that future offerings could be even better (NECEC Brief at 37, citing Exh. NECEC-NP-1, at 61-62).

13. PowerOptions

PowerOptions supports National Grid's commitment to the expansion of EV infrastructure and make-ready work in order to increase EV use and reduce GHG emissions (PowerOptions Brief at 3). Nonetheless, PowerOptions is concerned about National Grid's proposal to own a significant portion of the stations deployed through the Phase II EV Program, and it argues that, because the Company is a monopoly electric distribution company, such a proposal will not allow the developing EV charging market to flourish (PowerOptions Brief at 5). In addition, PowerOptions maintains that National Grid has not met the three-prong test in D.P.U. 13-182-A at 13 to demonstrate that Company ownership of charging stations is appropriate (PowerOptions Brief at 6). Specifically, PowerOptions maintains that the Company has not demonstrated that its Company-ownership proposal will meet a need that is not likely to be met by the competitive EV charging market (PowerOptions Brief at 6). PowerOptions argues that, in fact, utility-owned EVSE may hinder the development of the EV charging market because customers may choose the utility-owned EVSE option for its simplicity without understanding the impact of the decision (PowerOptions Brief at 8). In addition, PowerOptions claims that the approval of utility-owned EVSE would give National Grid a competitive advantage over private EV charging companies because the Company is guaranteed cost recovery, while private EV charging companies are not afforded such guarantees (PowerOptions Brief at 8, citing Exh. FSCS-JDM-Surrebuttal-1, at 4).

Finally, PowerOptions maintains that National Grid's Phase II EV Program lacks sufficient detailed information of Company-ownership of EV charging stations as well as consideration of other solutions (PowerOptions Brief at 9). PowerOptions asserts that, without this detailed information, the Department cannot determine whether the proposal is in the public interest (PowerOptions Brief at 9-10, citing Exh. FSCS-DH-1, at 6).

14. Tesla

Tesla supports the Company's proposed Phase II EV Program as a critical means of moving forward the Commonwealth's ambitious GHG reduction and transportation electrification objectives (Tesla Brief at 1; Tesla Reply Brief at 2). Tesla maintains that, contrary to some of the other intervenors' assertions, the Department did not require the conclusion of any evaluation of the Phase I EV Program as a predicate to the Phase II EV Program (Tesla Reply Brief at 3). Tesla also disagrees with any notion that the Company's proposed investments in private EVSE and its proposed fleet advisory services program is contrary to the record evidence and could inadvertently stall the Commonwealth's ability to achieve its ambitious GHG reduction and transportation electrification objectives (Tesla Reply Brief at 4).

Despite its overall support of the Company's proposal, Tesla argues that there should be changes to the proposed off-peak charging rebate program and the demand discount rate (Tesla Brief at 3; Tesla Reply Brief at 5-8). With respect to the proposed off-peak charging rebate program, Tesla argues that the Department should (1) approve an off-peak charging rate with a greater differential to provide a strong enough incentive for customers to consider investing in the necessary EVSE, (2) set a date certain by which National Grid must either propose an EV time-of-use rate or provide sufficient documentation demonstrating why such a rate is not appropriate, and (3) determine that the program design should be flexible to accommodate new charging technologies (Tesla Brief at 5-6, citing Exh. NG-RS-Rebuttal-1, at 30).

With respect to the proposed demand discount rate, Tesla argues that the rate should be made available to existing stations as well as new stations because those who bore the risk of early investing should not now be put at a competitive disadvantage (Tesla Brief at 7; Tesla Reply Brief at 7). According to Tesla, allowing the demand discount rate for existing stations would not require a budget expansion (Tesla Brief at 8, citing Exh. NG-RS-Rebuttal-1, at 33). As an initial matter, Tesla contends that the Company did not correctly estimate the number of charging stations its proposed rate relief would reach (Tesla Brief at 8). Tesla notes that the Company offered to consider developing an incentive structure for existing DCFC sites, and Tesla encourages the Department to direct the Company to re-evaluate and re-calculate the DCFC charging program costs and budget cap using kW nameplate capacity rather than total dollars per year (Tesla Brief at 8, citing Exh. NG-RS-Rebuttal-1, at 33-34; Tesla Reply Brief at 8).[190]

[190] In the interim, Tesla urges the Department to convert the Company's proposed program budget cap from a dollar budget to a kW nameplate capacity cap in order to provide charging station developers and site hosts with more certainty as to how much

Tesla also offers two additional modifications it asserts could render existing stations eligible for the discount without requiring a budget increase (Tesla Reply Brief at 7). First, Tesla proposes that the DCFC distribution demand charge discount could remain available to new stations, but at a reduced level, e.g., a 50 percent discount for new stations for year one through year three and then a 25 percent discount for year four, and a 12 percent discount for year five (Tesla Reply Brief at 7). Second, Tesla recommends that a small portion of the make-ready program be moved to the demand charge discount (Tesla Reply Brief at 8).

15. Company

National Grid maintains that the proposed Phase II EV Program meets the Department's standard of review (Company Brief at 332). Specifically, the Company argues that the proposal supports the Commonwealth's public policy goals, meets a need for ramping up the EVSE where it has not been met by the competitive market, and supports the development of the competitive market by expending opportunities for market participants (Company Brief at 332, citing Exh. NG-RS-1, at 16).

The Company disagrees with some of the intervenors that argue that the Department should defer the Phase II EV Program until after the results of the Phase I EV Program are reported (Company Brief at 365-366; Company Reply Brief at 117-118). National Grid maintains that evaluation results from the Phase I EV Program are not essential to the design of the Phase II EV Program (Company Brief at 365-366). While National Grid claims that it

capacity remains within the program (Tesla Brief at 8-9, citing Exh. TESLA-KB-Surrebuttal-1, at 13).

will use lessons learned from the Phase I EV Program to improve the Phase II EV Program, the Company asserts that the Phase II EV Program is not simply a continuation of the Phase I EV Program and, as such, it should not be deferred in an effort to sequence the two phases (Company Brief at 366, citing Exh. NG-RS-Rebuttal-1, at 8; Company Reply Brief at 119-120). The Company also argues that deferral would be detrimental to achieving the Commonwealth's environmental goals (Company Brief at 368-369; Company Reply Brief at 117-118).

The Company also disagrees with the notion that the Department should reject the Phase II EV Program because of its high cost when compared to other EV programs (Company Brief at 369, citing API Brief at 12-13). National Grid contends that such a comparison is misleading because to it is simply based on dollar amounts and does not consider the scope or scale of each program or the specific region's infrastructure (Company Brief at 369).

Further, the Company argues that while statewide coordination is laudable, the Department should continue to allow company-specific proposals to be reviewed and approved outside of a generic proceeding given the timetable necessary to accelerate EV adoption in the Commonwealth (Company Brief at 370). The Company also asserts that it is unclear how long a generic proceeding would take and how long of a delay in implementing its proposal would result (Company Reply Brief at 121).

In addition, the Company argues against any reduction to the budget or scope of the Phase II EV Program, or approval of only those aspects that are new or considered high priority (Company Brief at 380, citing, e.g., Attorney General Brief at 181; Acadia Center Brief at 19; DOER Brief at 11). National Grid maintains that the Phase II EV Program takes a holistic view of the EV market and will best address the Commonwealth's needs when it is approved in total (Company Brief at 372). The Company also contends that the Attorney General provided no explanation for how her proposed prioritization list was formed or what data was analyzed to determine segments of low priority and high priority programs (Company Brief at 381, citing Tr. 14, at 1706-1707). In addition, the Company maintains that an arbitrary cap of $12 million, based on priority programs, will seriously impede its ability to make a meaningful contribution to the Commonwealth's EV charging needs (Company Brief at 381).

National Grid also maintains that the R&D portion of the Phase II EV Program is distinct from those activities in the Phase I EV Program and that the marketing plan is a necessary component of the Phase II EV Program (Company Brief at 382, citing Exh. NG-RS-Rebuttal-1, at 27; D.P.U. 17-13, at 33). The Company notes that DOER has requested annual reporting of metrics related to National Grid's marketing efforts, and the Company states it will work with a third-party evaluation consultant to develop the appropriate metrics (Company Brief at 382-383, citing DOER Brief at 23-24).

With respect to the fleet advisory services, the Company states that it proposes to bear the entire cost of the offering because fleet customers' current operating budgets may not allow for this expenditure (Company Brief at 383-384). The Company maintains that if the Department disagrees with this approach, National Grid has provided a tiered price structure as an alternative (Company Brief at 384, citing Exh. DPU-NG 17-16). With respect to metrics sought by DOER regarding fleet advisory services, the Company states that it will develop appropriate metrics with its third-party evaluation consultant (Company Brief at 384).

National Grid does not support any revisions to the DCFC demand charge discount, such as extending it to existing stations (Company Brief at 384-385, citing, e.g., DOER Brief at 46, NECEC Brief at 37). The Company asserts that its proposed DCFC demand charge discount is intended to encourage the development of DCFC stations, which could be prohibitively expensive to operate during the early phase of the EV market due to low station utilization levels and demand-based delivery charges (Company Brief at 385). The Company maintains that if the demand charge discount was opened to existing DCFC sites, it would potentially reduce the number of new DCFC ports that would be incentivized by this offering (Company Brief at 385, citing Exh. NG-RS-Rebuttal-1, at 34). The Company also takes issue with the Attorney General's proposals to apply the discount only to the highest level of demand occurring during off-peak hours and require a certain threshold level of utilization to qualify for the demand charge discount (Company Brief at 385-386, citing Attorney General Brief at 190). Specifically, National Grid asserts that the Attorney General's proposals are geared more toward altering EV charging behavior, whereas the Company's proposal is designed to encourage the development of DCFC stations (Company Brief at 386, citing Exh. NG-RS-Rebuttal-1, at 33).

The Company also argues that its proposed off-peak rebate should not be altered in any way (Company Brief at 388-390). National Grid maintains that the proposed off-peak charging rebate will influence customers to adjust their charging behavior to charge during defined off-peak hours (Company Brief at 388-390

The Company also argues that it is unnecessary for the Department to condition approval of the Company's Phase II EV Program on the development of time-of-use rates (Company Brief at 390). The Company maintains that it will study data received through the Phase II EV Program to determine the effect of price signals on driver charging behavior to develop managed charging solutions and potential time-of-use rates in the future (Company Brief at 390).

Further, National Grid rejects any notion that the proposed level 2 residential program should be expanded or otherwise modified (Company Brief at 390-391). According to National Grid, there is no evidence that the Company's proposed rebate would be regressive (Company Brief at 391). Further, the Company notes that in developing its proposal, it has applied the same environmental justice community criteria that was developed and approved in the Phase I EV Program (Company Brief at 391, citing D.P.U. 17-13, at 30).

National Grid acknowledges concerns raised by some intervenors regarding the impact of the proposed Phase II EV Program on low-income communities, and the Company states it anticipates working closely with non-profit organizations operating and familiar with low-income and under-served communities in its service territory (Company Brief at 391-393). Nonetheless, the Company disagrees with a ten-percent floor on its investment in communities that meet at least one of the state environmental justice criteria, as proposed by CLF (Company Brief at 393). The Company notes that it has proposed a goal of ten-percent non-residential ports in disadvantaged communities and the only reason that less will be deployed is if the Company is unable to find customers (Company Brief at 393).

National Grid also maintains that it is unnecessary to establish a best practices working group to address low income communities, as the Company maintains that it actively participates in cross-jurisdictional internal groups with its affiliates, regularly meets with NSTAR Electric, and collaborates with stakeholders representing disadvantaged communities and low-income customers (Company Brief at 393-394). Further, National Grid contends that bill impacts show that electricity rates will stay affordable for low- and moderate-income customers (Company Brief at 394, citing Exh. Network 6-7).

Next, the Company maintains that it will work with an independent evaluation consultant to develop the detailed evaluation plan, but it disagrees with DOER's recommendation to combine the Phase I EV Program and the Phase II EV Program reports into a single report as each has separate annual filings (Company Brief at 396, citing Exh. NG-RS-1, at 57). According to National Grid, the goal of the evaluation plan is to assess both the intended and unintended effects of the Company's Phase II EV Program by quantifying the incremental effects of the program on EV adoption, customers, and charging infrastructure (Company Brief at 396, citing Exhs. NG-RS-1, at 57, DPU-NG 29-18). Further, the Company disagrees with eMotor Werks recommendations regarding issuing requests for qualifications to seek candidate EV service provider vendors and offering a utility-hosted webstore (Company Brief at 397, citing eMotor Werks Brief at 396). The Company maintains that the program is open to all EVSE vendors that meet the eligibility requirements and that the Company is not in the business of hosting webstores (Company Brief at 397).

Finally, with respect to the Company's ownership of EVSE, National Grid asserts that this aspect of its proposal has the support of those intervenors that are actually engaged in the EV market (Company Brief at 374, citing Tesla Brief at 3; ChargePoint Brief at 4, 10). Moreover, the Company asserts that it will own and operate only approximately three percent of its service territory EVSE need, and, therefore, there is sufficient need to be filled by the competitive market (Company Brief at 379, citing Exhs. NG-RS-1, at 23-24 & Table RS-3; FSCS 1-18).

D. Analysis and Findings

1. Introduction

In D.P.U. 13-182-A, the Department determined that it would not allow recovery of costs for distribution company ownership or operation of EVSE for new investments going forward, with a few exceptions. D.P.U. 13-182-A at 13. First, the Department found that the electric distribution companies may recover the cost of EVSE ownership and operation for their own vehicle fleet charging and employee vehicle charging. D.P.U. 13-182-A at 13. Second, the Department encourages investment in and cost recovery for research, development, and design related to EVs, EVSE, and EV charging as part of a distribution company's research, development, and design proposal in its grid modernization plan, or as a separate, approved pilot. D.P.U. 13-182-A at 13. Third, the Department concluded that it may grant cost recovery for an electric distribution company's EVSE ownership and operation in response to a company proposal. D.P.U. 13-182-A at 13. For Department approval and allowance of cost recovery, any proposal must be in the public interest, must meet a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market, and is not likely to hinder the development of the competitive EV charging market. D.P.U. 13-182-A at 13.

2. Phase II EV Program

a. Introduction

National Grid filed the instant proposal only two months after the Department approved the Phase I EV Program.[191] National Grid did not file its first annual reconciliation for the Phase I EV Program during the course of the instant proceeding, and, therefore, did not provide any formal evaluation results of its Phase I EV Program (Exhs. NG-RS-Rebuttal-1, at 9; DPU-NG 29-13). Further, the Company acknowledged during the proceeding that it had not overseen the installation of any EV charging stations, had not yet retained an independent evaluator, and had not finalized any evaluation results from the Phase I EV Program (see, e.g., Exhs. DPU-NG 29-13; DPU-NG 8-10; AG 18-1; AG 18-14). As such, the Department is unable to adequately measure the success of the Phase I EV Program, and, in particular, those components that are similar to those proposed in the Phase II EV Program. Accordingly, the Department finds that it is premature to

191 The instant filing was submitted on November 15, 2018. The Department issued its Order in D.P.U. 17-13 approving National Grid's Phase I EV Program on September 10, 2018.

approve in whole the Company's Phase II EV Program, absent evaluation results from the Phase I EV Program.

The Department, however, reiterates its commitment to the advancement of the Commonwealth's clean transportation and GHG emissions reduction goals. D.P.U. 17-13, at 1-3. In this regard, we are not persuaded that something less than a full approval of National Grid's proposal will negatively impact these goals, as suggested by some intervenors. Rather, after careful review of the Company's Phase II EV Proposal and the arguments of the intervenors, we find that it is reasonable and appropriate to approve several of the new components proposed in this proceeding, with modifications. Specifically, as discussed further below, the Department allows cost recovery for the following components of the Phase II EV Program: (1) residential off-peak charging rebate; (2) fleet advisory services plan; and (3) category 2 of the R&D plan.

Cost recovery for the remaining components of the Company's Phase II EV Program is disallowed at this time, including the bulk of the non-residential EV charging infrastructure construction and rebates for EVSE, the demand charge discount, the evaluation plan, and the marketing plan. We also reject the Company's proposal to own and operate a portion of the EVSE, while we note that some intervenors argue that such utility ownership of EVSE is needed, especially for DCFC EVSE and the deployment of EVSE in multi-unit dwellings (ChargePoint Brief at 7; Clean Energy Parties Brief at 19-20; DOER Brief at 18; eMotor Werks Brief at 11-12; Greenlots Brief at 12-14). The Department recognizes that there are challenges in deploying certain types of EVSE at certain sites. Nonetheless, the Department is not convinced that utility ownership of EVSE would effectively address these challenges. In particular, the Company's Phase I EV Program has not yet yielded any evaluation results, and the Company has not demonstrated any market failures that would prevent the competitive market from deploying EVSE, or that National Grid's ownership of EVSE would adequately address any market failure (Exhs. AG-EAB at 19-20; FSCS-JDM-1, at 11; DPU-NG 8-10; AG 18-1; AG 18-14).[192]

Further, National Grid's Phase II EV Program proposal includes a R&D Plan with three components: (1) category 1A - to demonstrate the economic viability of diesel bus electrification (e.g., municipal and school buses); (2) category 1B - to solicit solutions from third parties to increase electric transportation infrastructure and increase equitable access to EVs in disadvantaged communities; and (3) category 2 - to research the economic, environmental, grid, and customer benefits of co-locating DCFC charging stations with third-party deployed energy storage systems and solar facilities (Exh. NG-RS-1, at 59-65). The Attorney General recommends that the Department reject any new R&D funding, including category 2, arguing that R&D funding is already provided in the Phase I EV Program (Attorney General Brief at 186, citing Exh. AG-EAB at 26). For category 1A, while the Department appreciates the Company's intent to offer additional services to electrify diesel buses, we are concerned with the design of the program (Exhs. NG-RS-1,

192 Although the Department disallows Company ownership of level 2 and DCFC EVSE in this proceeding, the Department encourages the Company to consider plans for Company ownership of non-residential level 1 chargers in future EV proposals (e.g., placement of level 1 chargers at transit parking lots).

at 61-63; DPU-NG 29-28). Specifically, the Company has not conducted any analyses of the design of the financial reward as part of the program, and it has not established the breakdown of the benefit sharing mechanism (Tr. 1, at 66). The Department also is concerned that the Company has not conducted appropriate analysis of the category 1B program, including the types of services and costs (Tr. 1, at 56-58, 122-123). Therefore, the Department finds that the Company has not fully developed the proposed category 1A or category 1B components of the R&D plan. As such, we disallow the inclusion of categories 1A and 1B for cost recovery.

b. Approved Components of the Phase II EV Program

As noted above, the Department allows cost recovery for the following components of the Phase II EV Program: (1) residential off-peak charging rebate; (2) fleet advisory services plan; and (3) category 2 of the R&D plan. The Department finds that each of these new components is in the public interest, meets a need regarding the advancement of EVs in the Commonwealth that is not likely to be met by the competitive EV charging market, and does not hinder the development of the competitive EV charging market. D.P.U. 13-182-A at 13. Each component is discussed in further detail below.

i. Off-Peak Charging Rebate Program

As part of its residential offering in the Phase II EV Program, the Company proposes to provide its residential customers with an off-peak charging rebate program (Exh. NG-RS-1, at 24-25). Many intervenors are supportive of an off-peak charging rebate program, and some suggested certain modifications (Attorney General Brief at 189-190;

Acadia Center Brief at 20; DOER Brief at 14-15; eMotor Werks Brief at 10-11; FSCS Coalition Brief at 51-52; Tesla Brief at 4-6). The Department considers arguments in favor of an off-peak charging program to be persuasive. Indeed, many of these arguments are substantially consistent with prior Department findings. D.P.U. 17-13, at 36. For example, the Department has found that at higher EV adoption levels, the demand from EVSE would impose a significant impact on the electric grid during peak hours and the failure to prepare for the increased demand from EVSE would jeopardize some of the benefits from increased EV adoption. D.P.U. 17-13, at 36. The Department also has found that effective rate design for EV charging and the integration of demand response with EV charging will promote efficient charging behavior and can assist in securing the majority of the societal benefits related to EV infrastructure deployment. D.P.U. 17-05, at 490. Further, such rate structures would provide a meaningful economic incentive to support the development of the EV market as well as broader clean energy adoption. D.P.U. 13-182-A at 13.

Based on these considerations, the Department concludes that the proposed off-peak charging rebate program puts National Grid on the path to meeting the Department's objective of developing rate structures that encourage efficient charging behavior (e.g., off-peak charging), so that the Commonwealth can be prepared to manage EV load as EV adoption increases (Exhs. NG-RS-1, at 53; NG-RS-Rebuttal-1, at 29-30; TESLA-KB-1, at 14; CEP-1, at 13). In providing this incentive, the Company will be able to gain experience and gather data necessary to develop new time-of-use rates for EV customers in the future (Exh. NG-RS-1, at 30). Further, we expect the Company to use the information and results from this incentive program to develop new load management techniques and mechanisms as EV penetration increases (Exh. NG-RS-1, at 30).

The Department recognizes that the Company may want to adjust the off-peak charging rebates as market conditions change (Exh. NG-RS-1, at 27; Tr. 1, at 88-89). When such change is sought, National Grid may file a request with the Department for approval to change the rebates, along with appropriate testimony and documentation supporting the change. Further, while the Department finds it appropriate for National Grid to provide the off-peak charging rebate program to all eligible residential customers with or without level 2 charging equipment, the Company may not duplicate incentives to a customer for the single action of charging during off-peak hours (Exhs. NG-RS-1, at 27; DPU-NG 31-2; Tr. 1, at 78-80). Therefore, the Department directs the Company to coordinate internally between the off-peak charging rebate program and the energy efficiency program[193] to ensure that each participating residential customer participates in only one of the programs. The Department directs the Company to report on such coordination and any relevant tracking mechanism in its annual EV factor filing, consistent with the directives in Section XI.D.2.d., below.

Regarding additional particulars of the off-peak charging rebate, the Attorney General recommends shortening the peak window from the Company's proposed between 1:00 p.m.

---

[193] The Department approved National Grid's electric vehicle active demand reduction program as part of its 2019-2021 energy efficiency plan, which encourages off-peak charging. Three-Year Energy Efficiency Plans, D.P.U. 18-110 through 18-119, at 31 (January 29, 2019).

and 9:00 p.m. to between 2:00 p.m. and 7:00 p.m. (Attorney General Brief at 190; Attorney General Reply Brief at 67-68). The Department finds that National Grid supported its peak window period with sufficient evidence, including two years (2016 and 2017) of real-time ISO-NE pricing data for the three load zones in the Company's service area, load-weighted based on the Company's load across the three zones for 2017 (Exh. DPU-NG 8-6). The Company then evaluated a variety of periods in eight-hour increments comparing the energy costs in the potential peak periods to those in the potential off-peak periods (Exh. DPU-NG 8-6). This analysis included examining peak periods (in eight-hour increments) beginning at 8:00 am through peak periods beginning at 8:00 pm (Exh. DPU-NG 8-6). In contrast, the Department is not persuaded that the Attorney General's recommendation is supported by sufficient analysis to shorten the peak window period at this time (Exhs. AG-EAB at 35-36; NG-AG 2-6 & Atts.). Therefore, the Department declines to adopt the Attorney General's recommendation.

Regarding the development of time-of-use rates, some intervenors recommend that the Department direct the Company to develop such rates by a certain date (Acadia Center Brief at 20; CLF Brief at 21; Tesla Brief at 6). The Department finds that such rates for EV customers will be necessary to mitigate the impact of EV loads as adoption of EVs increases in the Commonwealth. Nonetheless, the Department recognizes that the data and information necessary to develop and implement time-of-use rates is not yet available (Exh. NG-RS-Rebuttal-1, at 34-35). Rather, we accept as reasonable the Company's position that it should be allowed to study the data that it receives through the Phase II EV Program concerning the effect of price signals on driver charging behavior in order to develop managed charging solutions and potential time-of-use rates in the future (Exhs. NG-RS-Rebuttal-1, at 34; DPU-NG 8-18). In the meantime, the Department expects the Company to make full use of the experience gained in the off-peak charging rebate program, as well as other data available to the Company, to use in developing EV time-of-use rates in future proceedings. In these future proceedings, the Department expects both the Company and stakeholders to fully participate and address issues related to time-of-use rates.

Finally, the Clean Energy Parties recommend that the Department augment the off-peak charging rebate values by including the benefits from avoided costs of transmission system upgrades, distribution system upgrades, and Global Warming Solutions Act compliance (Clean Energy Parties Brief at 22-23, citing Exh. CEP-1, at 45-46). eMotor Werks argues that the off-peak charging rebate value should be limited to a total of $5.00 per month and that the Company should use the remaining budget to support rebates that go directly towards the purchase and installation of EVSE (eMotor Werks Brief at 11). Tesla also suggests that the Department adjust the off-peak charging rebate level (Tesla Brief at 6, citing Exh. Tesla-KB-1, at 15-16).

The Department finds that the Company provided sufficient support for the off-peak charging rebate values, including wholesale energy market information (e.g., hourly loads, hourly energy prices, and capacity prices), as reported by ISO-NE in 2016 and 2017 for peak and off-peak periods in the summer and winter seasons (Exhs. NG-RS-1, at 24-30; NG-RS-6;

DPU-NG 8-4; DPU-NG 8-6; CEP 1-2). In contrast, the Clean Energy Parties did not provide any quantitative analysis of any potential avoided costs (Exh. CEP-1, at 45-46). Further, eMotor Werks only provided the recommendation to alter the off-peak charging rebate on Brief, but did not provide any record evidence to support its recommendation (eMotor Werks Brief at 11). Finally, we find that Tesla failed to provide any persuasive studies, formal surveys, or formal evaluations specific to experiences in the Commonwealth on off-peak charging to support its recommendations (Exhs. Tesla-KB-1, at 15-16; Tesla-KB-Surrebuttal-1, at 8-9; DPU-Tesla 1-1). Further, the Department is satisfied with the Company's method of calculating its rebate levels and we recognize that such levels likely will be revised in the future as National Grid gains experience in this area (Exhs. DPU-NG 8-4; CEP 1-2). For these reasons, the Department declines to adopt the recommendations provided by the Clean Energy Parties, eMotor Werks, and Tesla.

ii. Fleet Advisory Services Plan

The Company proposes to offer a fleet advisory services program to support the electrification of its customers' fleets (Exh. NG-RS-1, at 50-53). The Department recognizes that in this early stage of the EV market development, it would be valuable to assist fleet operators to navigate new challenges and provide such operators opportunities for reliable and cost-effective fleet electrification. Therefore, the Department approves the Company's fleet advisory services program, as set forth below.

First, the Department finds that only public transit (including school buses) and government fleets shall be eligible to participate in the fleet advisory services program at this time, consistent with the Company's intention to prioritize these segments (Exh. NG-RS-1, at 51). Second, the Department encourages the Company to prioritize eligible fleets that provide services in disadvantaged communities, as it stands to reason that populations within the low-income and disadvantaged communities are less likely to make private investments in EV and more likely to benefit from the public transit element of the fleet advisory services.

The Attorney General argues that the Department should require that the eligible fleets contribute at least 50 percent of the costs of the fleet advisory service (Attorney General Brief at 185, citing Exhs. AG-EAB at 26; DPU-NG 17-16). Given that the fleet advisory service is new and any cost barrier might inhibit customer participation and because we have limited the program to public transit and government fleets, we are not persuaded that it is appropriate to require any contribution from fleet customers (Exhs. DPU-NG 8-12; DPU-NG 17-16; DPU-NG 7-17). Therefore, we decline to adopt the Attorney General's recommendation. In addition the above findings, the Department directs the Company to (1) report on the progress of the fleet advisory services program annually and (2) coordinate with stakeholders on what information to include in the report.

iii. Research and Development Plan – Category 2

The Department declines to accept the Attorney General's recommendation as it applies to category 2. First, with respect to category 2 of the R&D program, the Department finds that it is distinct and new, as compared to the R&D funded in the Phase I EV Program (Exh. NG-RS-1, at 60). Specifically, category 2 is designed to research innovative solutions to mitigate the impacts of DCFC charging to the electric grid by combining the configurations of DCFC stations with energy storage and solar facilities (Exh. NG-RS-1, at 61-63). Second, the Department has found that at higher EV adoption levels, the demand from EVSE would impose a significant impact on the electric grid during peak hours, and that the failure to prepare for the increased demand from EVSE would jeopardize some of the benefits of increased EV adoption. D.P.U. 17-13, at 12. Based on these considerations, the Department allows the Company's category 2 component of the R&D Plan. The Department encourages the Company to prioritize category 2 program sites that are in a high traffic location, such as highway corridors, retail locations, and sites that would accommodate both energy storage and solar facilities (Exh. DPU-NG 29-29; Tr. 1, at 58-61).

c. Future EV Proposals

Although the Department disallows the majority of the Company's proposed Phase II EV Program for cost recovery at this time, our findings should be not be construed as opposing the expansion of the Company's EV Programs when appropriate. As the Company gains experience from its Phase I EV Program and the limited portion of the Phase EV II Program granted in this proceeding, National Grid may file future EV proposals under the umbrella of the grid modernization proceedings.[194] However, the Company shall make such a filing no earlier than its filing with the Department of evaluation results from year two of the Phase I EV Program.

194 The Department intends to address future EV proposals and statewide EV-related issues, such as EV infrastructure coordination and EV time-of-use rates, through future grid modernization proceedings. D.P.U. 17-05, at 482; D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 187.

Some intervenors argue that a statewide stakeholder process or generic EV proceeding may be necessary (Attorney General Brief at 190-191; Acadia Center Brief at 17; FSCS Coalition Brief at 17 n.7; MEDA Brief at 18). Other intervenors argue that participation by the low-income population and disadvantaged communities is necessary in the development and implementation of the Company's EV charging program (CLF Brief at 22; CLF Reply Brief at 6; DOER Reply Brief at 14-15; MEDA Brief at 18; MEDA Reply Brief at 9). A few intervenors also argue that the proposed Phase II EV Program did not include any time-of-use rates or EV load management techniques and that those items should be considered as part of an EV stakeholder process (Acadia Center Brief at 20; Clean Energy Parties at 22). The Department appreciates these constructive suggestions. At the present time, the Department will not open a generic proceeding or convene a statewide stakeholder process. The Department, however, expects National Grid to consider issues raised by these intervenors and to address them with stakeholders prior to submitting any future proposals.

d. Cost Recovery

Consistent with the findings in this section, the Department allows cost recovery for the following components of the Phase II EV Program: (1) residential off-peak charging rebate; (2) fleet advisory services plan; and (3) category 2 of the R&D plan. As is the case with any costs to be recovered from ratepayers, all Phase II EV Program expenditures must be prudently incurred to be eligible for cost recovery. D.P.U. 17-13, at 58. The Department's standard of review on prudence involves a determination of whether a company's actions, based on all that it knew or should have known at that time, were reasonable and prudent in light of the existing circumstances. 390 Mass. 208, 229. Department preauthorization of the Phase II EV Program means that the Department will not revisit the prudence of National Grid's decision to proceed with those categories of investments. Nonetheless, the Department will review the prudence of National Grid's implementation of these investments. D.P.U. 17-13, at 58; D.P.U. 15-120/D.P.U. 15-121/D.P.U. 15-122, at 220. The Department will review actual Phase II EV Program expenditures annually to determine if they are reasonable and prudently incurred.[195] All costs recovered from ratepayers for any expenditures later determined to be imprudent shall be refunded through the reconciliation component of the EV factor, with associated carrying charges. D.P.U. 17-13, at 60-61.[196]

The Company proposes to recover costs related to the Phase II EV Program through its electric vehicle market development program provision as approved conceptually in D.P.U. 17-13 (Exh. NG-RS-1, at 70). At this time, however, the Department has not approved the tariff associated with the Phase I EV Program in D.P.U. 17-13. D.P.U. 17-13, Hearing Officer Memorandum (October 31, 2018). Accordingly, the Department directs the Company in its compliance filing to make the following changes to the proposed electric

---

195 With each annual EV factor filing, the Company shall provide testimony and supporting exhibits, including full project documentation of all Phase II EV Program capital projects placed into service during the plan investment year and documentation of O&M expenses, describing in detail how the Company's proposed costs meet the eligibility requirements set forth in D.P.U. 17-13, at 56-60.

196 Pursuant to D.P.U. 17-13, at 61, for the purposes of the net metering credit calculation, net metering credits shall exclude the EV factor line item.

vehicle program provision: (1) delete Section 1 of the proposed tariff and replace the section with a placeholder;[197] (2) modify Section 2 to be consistent with the findings in this Order; (3) modify Section 3 to exclude references to the Phase I EV Program and any elements of the Phase II EV Program not approved in this Order; (4) revise the proposed tariff so that "Determination of Incremental Administrative Cost" is labelled as Section 4; (5) remove the section titled "Internal Labor" from Section 4; and (6) comply with all other directives pursuant to this Order (Exh. NG-HSG-13, Proposed M.D.P.U. No. 1399 (Bates Stamp 273-284)). In addition, we accept the Company's proposal to revise the tariff name to electric vehicle program provision.

XII. STORM COST RECOVERY MECHANISM

A. Introduction

The Department first approved a storm fund 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 the storm fund, but has implemented several modifications. D.P.U. 09-39, at 205-213; D.P.U. 15-155, at 75-79, 81-84; D.P.U. 15-155-A at 15-17. The most recently approved storm fund set forth the following parameters: (1) for any storm in which National Grid incurred more than $1.5 million in incremental O&M costs, the Company was permitted to access the storm fund for reimbursement of only that portion of the cost that exceeded $1.5 million; (2) a $10.5 million annual base distribution rate contribution to the storm fund;

[197] This section may be supplemented upon resolution of the outstanding issues in D.P.U. 17-13.

(3) a cap on single-storm incremental O&M costs of $30.0 million (net of Verizon costs); and (4) carrying cost accrual on storm fund eligible storms (i.e., storms with incremental O&M costs above $1.5 million, but below $30.0 million) at the prime rate. D.P.U. 15-155, at 76-79, 81-84; D.P.U. 15-155-A at 16. In addition to the $10.5 million contribution in base distribution rates, the storm fund is replenished through a storm fund replenishment adjustment factor ("SFRF"). D.P.U. 15-155, at 85.[198]

According to the Company, between March 2017 and April 2018, there were eight storms that qualified for cost recovery under the storm fund, and three storms (Winter Storms Riley and Quinn and Tropical Storm Philippe[199]) that exceeded the $30.0 million cap for recovery through the storm fund (Exhs. NG-RRP-1, at 57-60; AG 36-7, Att.). The Company calculates incremental storm costs of approximately $144.2 million (net of the $1.5 million per storm deductible) for these eleven storms (Exhs. NG-RRP-1, at 59-60;

---

198 The SFRF was approved in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 13-59 (2013) for a period of three years as a means to replenish the storm fund and minimize storm fund carrying costs on ratepayers. The Department approved SFRF extensions in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 13-85 (2016) and most recently in D.P.U. 15-155 with a current SFRF termination date of August 2019.

199 In its original filing, the Company identified Tropical Storm Philippe as a storm fund eligible storm (Exh. NG-RRP-1, at 59-60). During the course of the proceeding, the Company presented record evidence that, subsequent to the original filing, the incremental O&M expenses related to Tropical Storm Philippe now exceed the $30.0 million storm fund eligibility threshold (Exh. AG 36-7, Att. at 2). The Department's representation here of eight storm-fund eligible events and three storm-fund ineligible events is reflective of the additional expenses associated with Tropical Storm Phillipe provided by the Company during the course of the proceeding.

DPU-NG 12-2). National Grid also calculates that the residual balance in the SFRF at the end of August 2019, which the Company intends to collect from customers, will be approximately $28 million related to storm events from February 2010 through April 2016 (Exhs. NG-RRP-1, at 115; DPU-NG 7-10).

B. Company Proposal

The Company proposes to continue the storm fund and states that the increasing frequency and intensity of weather events have made for significant and persistently recurring restoration costs that are unsuitable for base distribution recovery (Exh. NG-RRP-1, at 68-72). The Company proposes to maintain the current $1.5 million incremental O&M cost-per-storm threshold, the $30.0 million cap required for accessing the storm fund, and carrying charges at the prime rate accrued each month on storm fund balances incurred from the time costs are incurred (Exhs. NG-RRP-1, at 57-58; DPU-NG 12-1).

National Grid proposes the following modifications and additions to its current storm fund. First, the Company proposes to increase the annual base distribution rate contribution to the storm fund from $10.5 million to $19.3 million, an increase of $8.8 million (Exhs. NG-RRP-1, at 59, 61-65; NG-RRP-2 (Rev. 4), Sch. 33 at 2, 3; WP NG-RRP-14 (Rev. 4), Sch. 33, at 1; NG-RRP-2 (Rev. 4), Sch. 3, at 2, line 22). Second, the Company proposes a normalizing adjustment to decrease the storm fund deductible by $1.5 million, from $7.5 million to $6.0 million, based on the historic average of four qualifying storm events per year over the period January 1, 2009 to April 30, 2018 (i.e., four storms times $1.5 million per-storm threshold) (Exhs. NG-RRP-1, at 58, 72-73; WP NG-RRP-14, at 2).

Third, National Grid seeks cost recovery through its exogenous cost provision of the PBR (pending a prudence review) should the combined balance of the storm fund and any costs associated with storm events over $30.0 million exceed $75.0 million (Exh. NG-RRP-1, at 66, citing D.P.U. 17-05, at 558-559).

Fourth, the Company proposes to extend the SFRF from August 2019 (the end date approved in D.P.U. 15-155), to November 2023,[200] in order to replenish the storm fund to account for the $144.2 million of incremental O&M expenses (net of $1.5 million deductible) of storm fund eligible storms that took place after the Company's filing in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 13-85 (2016) (between March 2, 2017 and April 30, 2018) and the three large-scale weather events (Winter Storms Riley and Quinn and Tropical Storm Phillipe) with incremental O&M costs (net of storm fund deductible) exceeding $30.0 million for each event (Exhs. NG-RRP-1, at 60, 116; NG-RRP-4 (Rev. 4), at 1, line 37; DPU-NG 7-4).[201] The Company calculates that the storm fund balance on August 31, 2019 (when the SFRF is set to expire, and a month before the start of the rate year) will be $122.6 million (Exhs. NG-RRP-1, at 116; NG-RRP-4 (Rev. 4), at 1, line 36). The Company anticipates that the residual balance, or deficit, in the regulatory

---

200 Initially the Company proposed to extend the SFRF to October 2023 (Exh. NG-RRP-1, at 117). During the proceeding, the Company amended its proposed SFRF extension date to November 2023 to account for an erroneous interest rate used in its initial calculation (Exhs. DPU-NG 7-14; DPU-NG 11-9).

201 The Company states that its SFRF extension proposal is not intended to represent a request for approval of the actual incremental O&M costs of the additional storms as that will be determined in separate storm cost recovery filings (Exh. NG-RRP-1, at 120).

asset recovered through the SFRF will be an amount owed to the Company from customers of approximately $28 million at the end of August 2019 (Exhs. NG-RRP-1, at 115; DPU-NG 7-10). The Company proposes to transfer the deficit balance to be collected through the SFRF to a separate regulatory asset, and to reset the storm fund balance to zero (Exh. NG-RRP-1, at 115). The Company proposes that the regulatory asset continue to accrue interest at the prime rate as approved in D.P.U. 15-155, at 84-85 (Exh. DPU-NG 17-1). Finally, while the Company does not seek to modify the carrying charges, it requests that the Department clarify the parameters for recovering carrying charges on storm costs for events with incremental O&M expenses in excess of $30.0 million where there is no finding of deficient performance in restoring power (Exh. NG-RRP-1, at 68, citing D.P.U. 17-05, at 556-557).

C. Positions of the Parties

1. Attorney General

a. Introduction

The Attorney General does not object to the Company's continuation of the storm fund but urges the Department to (1) reduce the Company's proposed annual contribution to the storm fund collected through base distribution rates from $19.3 million to $12.0 million (or less), (2) reject the Company's proposal to collect costs for storms greater than $30.0 million through the SFRF, and (3) decline the Company's request to make a finding in this proceeding regarding carrying charges on deferred storm costs (Attorney General Brief at 38; Attorney General Reply Brief at 18).

b. Storm Fund Contribution

The Attorney General asserts that the Company's proposal to increase the annual storm fund contribution in base distribution rates from $10.5 million to $19.3 million is too high in light of record evidence and Department precedent (Attorney General Brief at 38-40, citing, e.g., Exhs. AG 36-1; DPU-NG 7-7, Att.; D.P.U. 17-05, at 552-553 & n.288; D.P.U. 15-155, at 79). Instead, the Attorney General proposes that the Company's annual storm fund contribution should be increased from the current level of $10.5 million per year to $12.0 million (or less) per year (Attorney General Brief at 41).[202] The Attorney General maintains that National Grid made several errors in its annual storm fund contribution calculation, as discussed below, such as including inappropriate storm costs and failing to account for the $1.5 million deductible to be applied to each storm (Attorney General Brief at 39-40, citing, e.g., Exhs. AG 36-1; AG 36-5; AG 36-7, Att. at 4; DPU-NG 7-7).

The Attorney General arrives at her recommendation by calculating $15.6 million as the average annual amount of storm fund eligible expenditures (Attorney General Brief at 39-41). In determining the $15.6 million per year average annual storm fund contribution, the Attorney General calculated the Company's total incremental O&M costs eligible for storm fund recovery to be $145.6 million – a $34.6 million reduction from the

[202] The Attorney General asserts that her proposed $12.0 million per year annual storm fund contribution proposal is based on the Department's decision in D.P.U. 17-05 (NSTAR Electric base distribution rate case) whereby the Department approved a $10.0 million annual storm fund contribution (Attorney General Brief at 41, citing D.P.U. 17-05, at 553 n.229).

$180.2 million[203] proposed by the Company (Attorney General Brief at 40, citing Exh. AG 36-5).

The Attorney General's proposed $34.6 million reduction in incremental O&M storm fund eligible costs (between January 1, 2009 through April 30, 2018) has three parts. First, the Attorney General argues that the Company should remove $400,000 from the total incremental costs eligible for storm fund recovery because National Grid incorrectly identified the cost of the February 2010 windstorm as $9.0 million, rather than $8.6 million (Attorney General Brief at 38-39, citing Exhs. DPU-NG 7-7; AG 36-1). Second, the Attorney General asserts that the Company should recalculate the total incremental cost eligible for storm fund recovery to reflect a $1.5 million storm fund deductible applied to each storm[204], which results in a decrease of $5.0 million in total incremental costs (Attorney General Brief at 39-40, citing Exhs. AG 36-3; AG 36-5; D.P.U. 17-05, at 552-553 & n.288; D.P.U. 15-155, at 79). Third, the Attorney General argues that the $29.2 million of incremental O&M costs related to Tropical Storm Philippe should be removed from storm

---

203 The $180.2 million represents incremental O&M storm fund eligible costs related to 36 storms over the period of January 1, 2009 through April 30, 2018 (Exh. NG-RRP-1, at 62-63, 72; WP NG-RRP-14, at 2; AG 36-5, Att.).

204 The Attorney General asserts that the Company's proposed calculation on this matter accounts for the deductible as it pertained to each storm at the time of occurrence – representing a $1.25 million deductible for each storm prior to 2017 (Attorney General Brief at 39, citing Exh. DPU-NG 7-7). This approach, the Attorney General posits, is inconsistent with precedent, wherein the Department has approved calculations for annual storm fund contributions that apply the prospective deductible to past storms, as opposed to the deductible in place at the time of the storm (Attorney General Brief at 39, citing D.P.U. 17-05, at 552-553 & n.288; D.P.U. 15-155, at 79).

fund cost recovery as its updated incremental O&M costs now exceed the $30.0 million storm fund eligibility threshold (Attorney General Brief at 40, citing Exh. AG 36-7, Att. at 4; Tr. 7, at 917). The Attorney General asserts that, with these three adjustments, the Company's proposed incremental storm cost should be reduced by a total of $34.6 million ($400,000 + $5.0 million + $29.2 million), for a new total incremental O&M cost of $145.6 million (Attorney General Brief at 41).[205]

Next, the Attorney General takes the $145.6 million of the proposed total incremental costs eligible for storm fund recovery and divides this total by 112 months,[206] to yield $1.3 million (Attorney General Brief at 41, citing Exhs. NG-RRP-1, at 64; AG 36-5). The Attorney General then multiplies $1.3 million by twelve to calculate $15.6 million to represent the average annual amount of storm fund eligible expenditures (Attorney General Brief at 41).

Based on these calculations, the Attorney General argues that the Department should reduce the Company's request for an increase in the annual contribution to the Storm Fund by "at least $4.7 million"[207] (Attorney General Brief at 41). She also claims, however, that the Department should further reduce the Company's request for an increase so that the

---

205 By calculation: $180.2 million - $34.6 million = $145.6 million.

206 The Attorney General notes that 112 months is the number of months used by the Company (between January 1, 2009 through April 30, 2018) to calculate its annual storm fund contribution based on the storm fund qualifying costs incurred during this time period (Attorney General Brief at 38-39, 41, citing Exh. NG-RRP-1, at 64).

207 It appears the Attorney General means at least $3.7 million, as $19.3 less $3.7 million = $15.6 million.

annual Storm Fund contribution amount is not more than $12 million, as this further reduction will help address the disparity between the amount currently recovered in base distribution rates and the average annual amount of storm expenditures while, at the same time, maintaining relative consistency with the $10.0 million annual storm fund granted to NSTAR Electric (Attorney General Brief at 41, citing D.P.U. 17-05, at 553). The Attorney General rejects the Company's assertion that the $12.0 million proposal is arbitrary, and she notes that Company acknowledges on brief that the Attorney General's recommendation was based on the Department's most recent precedent on this matter (Attorney General Reply Brief at 19, citing Company Brief at 234). Based on these reasons, the Attorney General contends that the Department should adopt her recommendation and increase the annual amount contributed to the storm fund to no more than $12.0 million (Attorney General Reply Brief at 19).

c. Recovery of Three Storms Over $30.0 Million

The Attorney General argues that the Company's proposal to recover the costs associated with the three storms over $30.0 million (Winter Storms Riley and Quinn and Tropical Storm Philippe) through the SFRF is inconsistent with the Department's directives that any single storm event that exceeds $30.0 million in incremental costs must be excluded from storm fund eligibility (Attorney General Brief at 42, citing D.P.U. 15-155, at 82; Attorney General Reply Brief at 19-20). The Attorney General argues that, in D.P.U. 15-155, at 82, the Department directed the Company to seek deferral of any costs for storms exceeding $30.0 million in its next base distribution rate proceeding (Attorney General

Brief at 42; Attorney General Reply Brief at 19). The Attorney General notes that the Company has sought to defer these costs and has not yet received Department approval, and, as such, any costs related to these three storms must be recovered in the Company's next base distribution rate case rather than in the current proceeding (Attorney General Brief at 42-43, citing Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 19-38). The Attorney General also maintains that if the Department allows recovery of the storms exceeding $30.0 million through the storm fund, it will leave almost no distinction between the recovery of storm fund eligible storms and storms that do not qualify as storm fund eligible (Attorney General Brief at 43; Attorney General Reply Brief at 20).

Further, the Attorney General argues that the Company has made inconsistent arguments regarding Tropical Storm Phillipe on brief in this proceeding and in a separate proceeding (Attorney General Reply Brief at 19). Specifically, the Attorney General maintains that on brief in the instant proceeding, the Company asserted that it is appropriate to recover Tropical Storm Phillipe through the storm fund because it represents a commonplace storm and not a statistical outlier, while in another docket, the Company characterized Tropical Storm Phillipe costs as extraordinary, non-recurring storm-restoration expenditures (Attorney General Reply Brief at 19, citing Company Brief at 235; D.P.U. 19-38, Company Brief at 1).

The Attorney General also maintains that the Company ignores that the storm fund cost calculation is used to determine an average annual amount of storm expenditures eligible for storm fund recovery (Attorney General Reply Brief at 19, citing D.P.U. 17-05, at 552).

Further, the Attorney General argues that the Company's application of the $1.5 million storm fund deductible to each of the three storms in excess of $30.0 million of incremental O&M, is inappropriate as these storms are ineligible for storm fund recovery (Attorney General Brief at 43, citing D.P.U. 15-155, at 77; Attorney General Reply Brief at 20).

d. Carrying Charges

With respect to the Company's request for clarification regarding carrying charges, the Attorney General maintains that the Department has stated that it would address the issue during any prudency review (Attorney General Brief at 44, citing D.P.U. 17-05, at 556-557). Consistent with the Department's decision in D.P.U. 17-05, the Attorney General asserts that the Department should refrain from a decision on the application of carrying charges on deferred storm costs (including when carrying charges begin to accrue) until the Company files with the Department for storm cost recovery and the Department reviews these costs for prudency (Attorney General Brief at 44, citing D.P.U. 17-05, at 556-557; Attorney General Reply Brief at 20). The Attorney General argues that the Company's assertions that failure to clarify the carrying costs will result in financial harm, is "based on a hypothetical" (Attorney General Reply Brief at 20).

2. Company

a. Introduction

The Company asserts that its proposed changes to the storm fund reflect updated information regarding the Company's actual storm experience and eliminated deferred balances for storms covered by the terms of D.P.U. 09-39 and D.P.U. 15-155 (Company

Brief at 225, citing Exh. NG-RRP-1, at 58). The Company maintains that need for these changes stems from the accelerated frequency and increasing severity of major storm events that the Company has been experiencing (Company Brief at 225, citing Exh. NG-RRP-1, at 59).

b. Storm Fund Contribution

The Company asserts that its proposal to increase the annual storm fund collected through base distribution rates from $10.5 million to $19.3 million is appropriate to provide rate stability (Company Brief at 226). In addition, National Grid asserts that its proposal is reasonable and backed by record evidence (Company Brief at 226, 234; Company Reply Brief 149-150, citing Exhs. NG-RRP-1, at 62-63, Table 18; NG-RRP-4, at 2; DPU-NG 7-3; DPU-NG 7-13).

The Company asserts that the Department should reject the bulk of Attorney General's proposed adjustments (Company Brief at 234). The Company agrees with the Attorney General's proposal to remove $400,000 of expenses related to this matter, but asserts that this $400,000 change is the only adjustment that has any merit (Company Brief at 234). The Company argues that the Department should disregard the Attorney General's recommendation to remove from storm cost recovery $29.2 million of incremental O&M costs related to Tropical Storm Philippe because, as she argued, the cost of this storm exceeded $30 million before application of the $1.5 million deductible (Company Brief at 235). According to the Company, major storms in excess of $30.0 million are more commonplace[208] and can no longer be considered statistical outliers (Company Brief at 235; Company Reply Brief at 150-152, citing Exhs. DPU-NG 12-3; WP NG-RRP-14; DPU-NG 7-7, Att.). Further, the Company asserts that excluding Tropical Storm Philippe from the storm costs to be recovered in base distribution rates does not benefit customers as it understates the appropriate rate allowance for storm fund recovery (Company Reply Brief at 151, citing Exh. DPU-NG 12-3). The Company also disagrees with the Attorney General's proposed exclusion of $5.0 million of storm costs on the grounds that the Company should have deducted a $1.5 million deductible per storm for storm events occurring prior to October 1, 2016, rather than the applicable deduction at that time of $1.25 million per storm (Company Brief at 235). The Company asserts that the Attorney General's exclusion proposal is unreasonable in that storm costs for pre-October 1, 2016, major storm events would be more costly in today's dollars and would be even more costly had such storms occurred during the five-year PBR stay-out period (Company Brief at 236).

In addition, the Company asserts that the Attorney General's proposal for an annual storm fund collection of $12.0 million or less is vague, lacks substantive calculations, and is based on the business decision of NSTAR Electric in its most recent base distribution rate case to reduce its storm fund contribution below the average storm fund eligible costs (Company Reply Brief at 149, citing D.P.U. 17-05, at 532). The Company also argues that

---

208 The Company states that, of the 36 major storm events that occurred between February 2010 and April 2018, six of those events had incremental O&M storm restoration costs in excess of $30.0 million before applying the $1.5 million per storm deductible (Company Brief at 235).

the Attorney General's aim with her proposal to allow $12 million or less in the annual storm fund collection is to achieve the lowest possible increase to the storm fund rate allowance, which is not in the best interest of customers and will not accomplish the Department's goal of rate stability over time (Company Brief at 235).

c. Recovery of Three Storms Over $30.0 Million

The Company argues that the Department should reject the Attorney General's recommendation to exclude recovery of three storms (Winter Storms Riley and Quinn and Tropical Storm Phillipe) through the storm fund (Company Brief at 236). National Grid asserts that it requested deferral of these storm costs for incorporation into either (1) recovery through the existing storm fund or (2) the ratemaking schedule for storm events qualifying for treatment as post-test-year exogenous events pursuant to its PBR proposal (Company Brief at 236-237, citing D.P.U. 19-38). The Company maintains that if the PBR is granted, National Grid will be precluded from filing a base distribution rate case for five years, so if the exogenous cost provision related to qualifying storm events is denied, the Company may be required to wait to include the costs of these events and any ensuing qualifying storm events until October 1, 2024 (Company Brief at 236-237). Further, National Grid argues that it will be necessary for the Department to conduct a prudence review and rate recovery through the ratemaking mechanism in place to recover for exogenous storm costs under the PBR mechanism, which the Company contends is the existing SFRF or a similar factor (Company Brief at 237). The Company also maintains that the Attorney General's proposal would be harmful to customers as it would delay recovery of these costs at the prime rate, thus increasing costs to customers (Company Brief at 237). Finally, with respect to the Attorney General's assertion that the Company gave inconsistent arguments regarding Tropical Storm Phillipe, National Grid counters that its labelling of Tropical Storm Philippe as extraordinary for purposes of cost deferral does not change the fact that the Company has experienced a growing number of storms since 2009 of increasing intensity, rendering these larger storms more commonplace (Company Reply Brief at 152).

d. Carrying Charges

The Company maintains that in D.P.U. 17-05, at 556-557, the Department made clear that it would consider the recovery of carrying charges for large-scale storms only after it had investigated the circumstances surrounding the incurrence of the costs to which the carrying charges would apply (Company Brief at 228). The Company asserts that the Department did not explain how the carrying charges would apply to large-scale storms in the event that a company's storm performance met the Department's standards and, as such, the Company seeks clarification (Company Brief at 228). National Grid asks that the Department determine that, where there is no finding of deficient performance in restoring power after a large-scale event, electric distribution companies will be authorized to recover carrying charges on the deferred balance of storm costs at the prime rate beginning with the date of cost incurrence (Company Brief at 228).

e. Extension of the SFRF

The Company maintains that it proposes to extend the SFRF beyond its current expiration date to work down deferred storm costs to a more reasonable level (Company

Brief at 223). The Company asserts that its proposal to extend the SFRF to at least November 2023 is consistent with the Department's rulings in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 13-59 (2013), D.P.U. 13-85, and D.P.U. 15-155 (Company Brief at 440, 441). The Company further asserts that, identical to the Department-approved SFRF treatment in D.P.U. 15-155, it proposes to transfer the deficit balance of the storm fund as of September 30, 2019 into a separate regulatory asset, and set the new storm fund to start with a zero balance on October 1, 2019 (Company Brief at 440).

According to the Company, extending the SFRF and recovering costs for storms through the SFRF – including storms with incremental O&M costs in excess of $30.0 million – will (pending prudence review) provide benefits to customers (Company Reply Brief at 152). The Company claims such an extension will eliminate the storm fund deficiency for costs incurred during the interim period between rate cases, and it will avoid carrying charges to the benefit of ratepayers (Company Brief at 440). More specifically, the Company asserts that under its SFRF proposal, customers will pay approximately $17.8 million in interest on the projected storm fund deficiency, whereas if the SFRF is not extended, customers would pay approximately $45.4 million in interest on the projected storm fund deficiency (Company Reply Brief at 152, citing Exh. DPU-NG 7-14, Atts. 1, 2). The Company, therefore, calculates that customers will save approximately $27.6 million in interest expense ($45.4 million - $17.8 million) by its proposal to extend the SFRF to

November 2023, and recover the costs of storms (including storms with costs in excess of $30.0 million) (Company Reply Brief at 152, citing Exh. DPU-NG 7-14, Atts. 1, 2).

The Company asserts that its requested extension of the SFRF does not diminish the Department's ratemaking authority in that costs recovered through the SFRF are reconciled after a full Department prudency review of all charges (Company Brief at 440). Coupled with the approximate $28 million residual deficit balance that will exist on August 31, 2019, and the likelihood that the Company will experience significant weather events in the ensuing period, the Company argues that allowing the extension of the SFRF to at least November 2023 would reduce the balance of the storm deferral (Company Brief at 441). The Company concludes that extension of the SFRF to at least November 2023[209] would reduce carrying charges borne by customers, and would ensure rate stability as required by the Department in D.P.U. 15-155 (Company Brief at 232-233).

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. 15-155, at 73; D.P.U. 13-90, at 13, citing D.P.U. 10-70, at 201-202; D.P.U. 09-39, at 206. The

---

[209] The Company estimates that November 2023 represents the date by which the SFRF would recover the deferred storm balance (subject to updates to account for incremental costs resulting from storm fund qualifying storm events through September 30, 2019) (Company Brief at 441-442). The Company states that a final SFRF extension date would be requested in its compliance filing related to this docket (Company Brief at 442, citing Exhs. NG-RRP-1, at 117; DPU-NG 7-12; DPU-NG 11-9; Tr. 7 at 918).

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 electric distribution companies 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, electric distribution companies 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 has increased (see, e.g., Exhs. NG-RRP-1, at 60; DPU-NG 12-2 (outlining eight storm eligible events and three large-scale weather storm events between March 2017 and April 2018)).

We acknowledge that the Company's current storm fund mechanism 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 deficit, which has expanded even further due to the accumulation of a significant amount in carrying charges.[210] The frequency and severity of these storms could not have been anticipated when the Company's storm fund mechanism was developed, or when it was most recently refined in D.P.U. 15-155. Because of the increase and frequency and severity of storms, without a storm fund 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 could 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 mechanism in the instant proceeding (see Section II.B.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 can provide for adequate recovery of storm costs in a manner that is

---

[210] The Company estimates that the current storm fund balance at September 2019 will be \$149,821,780, which includes \$9,636,099 of carrying charges (Exh. NG-RRP-4 (Rev. 4), at 1, line 36). This figure is for incremental O&M storm costs incurred for the period October 2016 through September 2019.

designed to create rate stability. Based on the foregoing, the Department allows the Company to retain its storm fund with the following modifications.[211]

3. Modifications to the Storm Fund

a. Introduction

The Attorney General contests three of the Company's proposed changes: (1) the amount to be included as the annual contribution to the storm fund; (2) the recovery of costs through the SFRF for three storms exceeding $30.0 million of incremental O&M; and (3) the requested clarification regarding the carrying charges on deferred storm costs. First, we discuss the uncontested issues and then discuss the Attorney General's proposed changes.

b. Uncontested Issues

i. Cost-Per-Storm Threshold

Currently, for any storm in which National Grid incurs more than $1.5 million in incremental O&M costs, the Company is permitted to access the storm fund for reimbursement of only that portion of the costs that exceed $1.5 million. D.P.U. 15-155, at 76-77. In D.P.U. 15-155, at 76, the Department increased the Company's cost-per-storm threshold from $1.25 million, which was established in D.P.U. 09-39, to $1.5 million to account for the effect of inflation on costs. The Department based the increase on the GDP-PI from the U.S. Bureau of Economic Analysis for the period between 2009 and June 30, 2015. D.P.U. 15-155, at 76-77.

211 Pursuant to the provisions of the Company's PBR mechanism approved herein by the Department, the Company will have a five-year stay-out period (see Section II.B.4., above). After that time, the Department will have an opportunity to review the storm fund and determine whether it should continue further.

In the instant proceeding, neither the Company nor the Attorney General proposes changes to the current $1.5 million cost-per-storm threshold. Nonetheless, the Department finds it appropriate to increase the cost-per-storm threshold to account for the effect of inflation on costs. During the proceeding, the Company calculated an inflation-adjusted cost-per-storm threshold of $1.55 million by comparing the GDP-PI in the fourth quarter of calendar year 2017 to the GDP-PI in the third quarter of calendar year 2016 (Exh. DPU-NG 11-4 & Att.). The Department has reviewed the Company's cost-per-storm threshold calculation and finds it to be reasonable and consistent with the method for applying a GDP-PI inflation factor approved in D.P.U. 15-155. For these reasons, we approve a cost-per-storm threshold of $1.55 million per storm. We find that this increased cost-per-storm threshold provides an appropriate balance between providing National Grid with necessary access to the storm fund to recover costs associated with major storms and ensuring that the routine storms are not contributing to a storm fund deficit balance. Consistent with Department's findings in D.P.U. 15-155, at 77-81, we find that an increase in the cost-per-storm threshold applicable to the storm fund also necessitates a change in the amount the Company collects through base distribution rates to (1) contribute to the storm fund (which, as a contested issue, is discussed below), and (2) recover O&M costs up to the $1.55 million threshold for storms that qualify for the storm fund, as well as (to the extent applicable) costs associated with smaller storm events that no longer qualify for storm fund recovery. Further, the annual storm fund contribution calculation uses the storm fund deductible amount (in this case, now $1.55 million rather than $1.50 million as proposed by the Company).

ii. Annual O&M Expense in Base Distribution Rates

As noted above, the Department has previously stated that if there is an increase in the cost-per-storm threshold to access the storm fund, an increase in the test year amount collected in base distribution rates is also warranted. D.P.U. 15-155, at 77. As discussed above, the Department determined that, consistent with the precedent established in D.P.U. 15-155, it is appropriate to apply the GDP-PI to determine an updated storm fund deductible (from $1.5 million per storm to $1.55 million per storm) necessary to access the storm fund, which results in an increase of $50,000 per storm (Exh. DPU-NG 11-4 & Att.). Because neither the Company nor the Attorney General proposed an increase to the current $1.5 million storm fund deductible, neither proposed an accompanying increase collected in base distribution rates to account for a change in per storm deductible. Here, the Department makes this adjustment based on the $50,000 increase in the per storm deductible from $1.5 million to $1.55 million.

As previously noted, $7.5 million is the Company's current test-year level of O&M expense included in base distribution rates to account for the five storm fund eligible storms that occurred during the test year, i.e., January 1, 2017, to December 31, 2017, at the $1.5 million deductible per storm ($1.5 million x five storms). The Company proposes to collect $6.0 million per year in base distribution rates to account for an average of four normalized storms per year at the current $1.5 million deductible level (Exh. NG-RRP-2

(Rev. 4)). Applying the updated deductible of $1.55 million per storm to the normalized average of four storms per year yields $6.2 million per year to be collected in base distribution rates for deductible expenses ($1.55 million x four storms). This represents a $200,000 increase over the $6.0 million contribution for deductible in base distribution rates proposed by the Company ($6.2 million - $6.0 million). The Department did not identify any storms that were eligible for storm fund recovery under the $1.5 million deductible, but ineligible under the $1.55 million deductible (Exh. NG-RRP-1, at 62-63). Therefore, no further adjustments are necessary to account for such storms in base distribution rates. Accordingly, the Department will increase the Company's proposed cost of service by $200,000.

iii. Extension of the SFRF

The Department extended the SFRF in both D.P.U. 13-85 and D.P.U. 15-155 in order to continue collection of the storm fund balance. D.P.U. 15-155, at 84; D.P.U. 13-85, at 105. Here, National Grid proposes to extend the SFRF from August 2019 to November 2023, to replenish the existing storm fund to account for additional storm costs of approximately $150 million[212] and minimize carrying costs associated with these storms (Exhs. NG-RRP-1, at 115-116; NG-RRP-4 (Rev. 4), at 1). Further, the Company proposes

---

212 The Company's storm fund deficit balance includes $144,161,164 for storms between March 2017 and April 2018 and includes both storm fund eligible and storm fund ineligible storms (Exh. NG-RRP-1, at 60). When coupled with the existing $28 million of residual SFRF balance and the monthly storm fund contribution of $875,000, the storm fund deficiency balance was expected to be approximately $150 million as of August 2019 (Exhs. NG-RRP-1, at 115; NG-RRP-4 (Rev. 4), at 1).

to transfer the deficit balance to be collected through the SFRF to a separate regulatory asset, and to reset the storm fund balance to zero (Exh. NG-RRP-1, at 115). The Company proposes that the regulatory asset continue to accrue interest at the prime rate as previously approved by the Department (Exh. DPU-NG 17-1, citing D.P.U. 15-155, at 84-85). The Department notes that, consistent with our findings in D.P.U. 15-155, at 84-85, the carrying charge to be applied to the balance in the SFRF regulatory asset related to post-October 2016 major storms will be at the prime rate (Exhs. DPU-NG 17-1; DPU-NG 26-2 & Att.).

The storm fund mechanism, as modified in the instant case, will be applicable to storms occurring after October 1, 2019. Further, and previously noted, the Department has in the past approved the transferring of the balance of the storm fund to the SFRF, then extending SFRF and recovery timeline, and zeroing-out the storm fund balance. D.P.U. 15-155, at 84-85; D.P.U. 13-85, at 104-105. Here, we find that the Company's proposal to transfer the balance associated with the current storm fund balance to a separate regulatory asset, zero out the storm fund, and extend the SFRF an additional 50 months to continue collecting that balance is reasonable, appropriate, and consistent with precedent. Further, and as approved in D.P.U. 15-155, at 85, we find it appropriate to transfer any residual balance to the storm fund at the end of the SFRF recovery period. Based on these considerations, we approve the Company's proposal to extend the SFRF to November 2023.

iv. Exogenous Cost Recovery Through the PBR

National Grid proposes cost recovery through the exogenous cost provision of the PBR mechanism (pending prudence review) provided that the combined balance of the storm fund and any costs associated with storm events over $30.0 million exceed $75.0 million (Exh. NG-RRP-1, at 66). National Grid states that this proposal is consistent with the Department's findings in D.P.U. 17-05 (Exh. NG-RRP-1, at 66, citing D.P.U. 17-05, at 558-559). Further, the Company states that, given the five-year stay-out provision of its PBR Plan (approved in the instant filing), it is important for the Company to have a path forward to begin prudence review and cost recovery proceedings when the deferred balance of storm costs reaches a level of significance (Exh. NG-RRP-1, at 65).

In D.P.U. 17-05, at 558, the Department rejected NSTAR Electric's proposal to file for a "replenishment factor" if the combination of the company's single storm deferral balance exceeds $75.0 million (i.e., the total sum of all single storms in excess of $30.0 million exceeds $75.0 million and/or the balance in the storm fund exceeds $75.0 million). NSTAR Electric argued that the replenishment factor would reduce the outstanding unrecovered storm fund balance, and minimize carrying charges. D.P.U. 17-05, at 533, 558. The Department declined to approve the proposed replenishment factor and instead determined that NSTAR Electric could seek cost recovery through the exogenous cost provision of the PBR (pending a prudence review) provided that the combination of any single storm in excess of $30.0 million and balance of the storm fund exceed $75.0 million. D.P.U. 17-05, at 558-559.

The Department finds that National Grid's exogenous cost recovery proposal is consistent with the recovery option approved for NSTAR Electric in D.P.U. 17-05, at 558-559. Further, there is no evidence on the record that would cause us to reach a different conclusion in this case than the Department reached in D.P.U. 17-05 with respect to this aspect of the Company's proposal. Accordingly, the Department approves the Company's proposal to seek cost recovery through the exogenous cost provision of the PBR Plan (pending prudence review) provided that the combined balance of the storm fund and any costs associated with storm events over $30.0 million exceed $75.0 million.

c. Contested Items

i. Storm Fund Contribution

National Grid's current $10.5 million annual base distribution rate contribution to the storm fund was established in the Company's last base distribution rate case. D.P.U. 15-155, at 77-79. The Company proposes to increase the annual base distribution rate contribution to the storm fund from $10.5 million to $19.3 million, an increase of $8.8 million (Exhs. NG-RRP-1, at 59, 61-65; NG-RRP-2 (Rev. 4), Sch. 33 at 2, 3; WP NG-RRP-14 (Rev. 4), Sch. 33, at 1; NG-RRP-2 (Rev. 4), Sch. 3, at 2, line 22). The Company argues that the current annual storm fund contribution of $10.5 million in base distributions rates is insufficient because the number of qualifying events is increasing in frequency and severity (Company Brief at 225, citing Exh. NG-RRP-2 (Rev. 3), Sch. 33). The Attorney General argues that, in light of record evidence and Department precedent, the Company's proposed $19.3 million annual storm fund contribution is too high, and the Attorney General proposes that it be increased from the current level of $10.5 million per year to $12.0 million per year or less (Attorney General Brief at 38).

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. As evidenced by the number of major storms since the Company's last rate case and the resulting significant deficit balance in the storm fund, the annual base distribution rate contribution amount of $10.5 million per year has proven to be insufficient to maintain rate stability (see, e.g., Exh. NG-RRP-4 (Rev. 4), at 1). D.P.U. 13-85, at 101, 106 (approving the recovery of costs associated with 16 major storms); D.P.U. 13-59 (approving the recovery of $120.0 million in storm costs over a three-year period). Thus, we conclude that an increase to the annual contribution to the storm fund is warranted.

The Department strives to set a new annual contribution amount that will permit the Company to recover storm costs over time without generating a surplus or deficit balance in the storm fund that exceeds the $30.0 million cap. We recognize the uncertainty in achieving this result given the unpredictable nature of the weather in general, and storm events in particular. The Department is in no better position to predict the frequency of future storm events than is the Company or the Attorney General. Further, we acknowledge that while data associated with past major storm events provides a historical perspective regarding the frequency, severity, and costs of major storms, such information is not necessarily predictive of future events. Notwithstanding these considerations, we conclude that the Company's storm fund history is instructive in the context of setting the parameters for the fund's continuation.

The Department has reviewed the record supporting the positions advanced by the Company and the Attorney General (see, e.g., Exhs. NG-RRP-1, at 62-63; NG-RRP-4 (Rev. 4); DPU-NG 7-3; DPU-NG 7-7; AG 36-1 through AG 36-7). In identifying common ground relative to the annual storm fund collection in base distribution rates, the Department notes that both the Company and the Attorney General use the Company's proposal of net incremental O&M storm costs of 31 storm-fund eligible events[213] totaling $180.2 million (occurring in the 9.3 years between January 2009 and April 2018) as the baseline figure from which each of their respective annual storm fund calculations begin. We note that the Attorney General does not dispute the method employed by the Company to calculate its annual storm fund contribution, but argues that the $180.2 million total should be reduced as discussed in detail below (Attorney General Brief at 38-41). The Department has reviewed the mechanics of the Company's annual storm fund calculation and finds it to be reasonable.

Both the Company and the Attorney General agree that $400,000 should be removed from the $180.2 million total because the Company incorrectly identified the cost of one storm at $9.0 million rather than $8.6 million (Attorney General Brief at 38-39, citing Exhs. DPU-NG 7-7; AG 36-1 (Company Brief at 234). The Department agrees, and, therefore, we reduce the storm fund expenses by $400,000.

Next, the Attorney General asserts that the $180.2 million of storm fund expenses should be further reduced by $29.2 million to account for the removal of the restoration costs

---

[213] Storm-fund eligible events in this context is to mean storms that were storm-fund eligible based on the deductible at the time for each event.

associated with Tropical Storm Philippe (Attorney General Brief at 40). At the time of the Company's initial filing, the incremental O&M costs related to Tropical Storm Phillipe were less than $30.0 million making it storm fund eligible. During the course of the proceedings, evidence was presented to demonstrate that the costs related to Tropical Storm Philippe had increased and exceeded $30.0 million, thereby rendering Tropical Storm Philippe storm fund ineligible (Exh. AG 36-7, Att.). Therefore, we remove from the $180.2 million of storm fund expenses $29.2 million in incremental O&M costs associated with Tropical Storm Phillipe.

The Attorney General also asserts that $5.0 million should be removed from the $180.2 million of storm fund expenses because the Company should have applied a $1.5 million deductible to all 31 storms as opposed to the $1.25 million deductible to those storms that occurred prior to October 1, 2016 (Attorney General Brief at 39-40). In D.P.U. 15-155, at 79, we established the current annual storm fund contribution amount by identifying storms that would be ineligible for storm fund recovery if the deductible cost-per-storm was set to the then-proposed threshold deductible amount, i.e., $1.5 million. More specifically, as a component to its annual storm fund contribution calculation, the Department did not apply the then-applicable deductible amount per storm, as is proposed by the Company in the instant proceeding. D.P.U. 15-155, at 79; see also D.P.U. 17-05, at 552-553 & n.288. Based on these considerations, we find that in determining National Grid's storm fund contribution amount, it is reasonable and appropriate to apply the $1.5 million deductible to all 31 storms. The record shows that if the Company had applied the current $1.5 million deductible to all 31 storms, the total storm fund expense would be reduced by $5.0 million (Exh. AG 36-5, Att.).[214] Therefore, we remove from the $180.2 million of storm fund expenses $5.0 million, subject to further adjustment below.

Specifically, the $180.2 million of storm fund eligible expenses associated with 31 storms (net of the current $1.5 million deductible and Verizon costs incurred from February 2010 through April 2018) must be further adjusted to apply the $1.55 million deductible to each storm fund eligible storm, consistent with our findings above. Each of the incremental O&M expenses of the 31 storms is further reduced by $50,000 representing the difference between the current deductible of $1.5 million and the deductible of $1.55 million approved in the instant proceeding, for a reduction of $1.55 million ($50,000 x 31 storms). Therefore, we remove from the $180.2 of storm fund expenses an additional $1.55 million.

The above-identified deductions total $36.2 million ($400,000 + $29.2 million + $5.0 million + $1.55 million).[215] As such, the Company's storm fund expense total is reduced to $144.0 million ($180.2 million less $36.2 million). Finally, the $144 million figure is divided by the 9.3 years (representing the period over which the 31 storms

---

214 The Department notes that in Exhibit AG 36-5, Att., the Company re-calculated its total incremental storm cost to reflect a storm fund deductible of $1.5 million applied to each storm. As discussed below, the Department has found that $1.55 million per storm is a more appropriate storm fund deductible. Therefore, the Department applies the $1.55 million deductible per storm to the 31 storms contained in the historical storm fund costs. This exercise, however, nets no additional storms that, for the sole purpose of calculating the annual storm fund contribution, become storm fund ineligible.

215 In determining the level of storm fund expense, amounts have been rounded.

occurred) to yield $15.5 million of annual storm fund contribution. Based on the foregoing and our review of the record, we find that setting the annual storm fund contribution at $16.0 million provides sufficient funds to levelize the rate impact for major storms that are eligible for recovery through the fund while also decreasing the likelihood that the fund will have a large deficiency balance. Further, we find that neither the Company's proposed storm fund contribution of $19.3 million nor the Attorney General's recommended amount of no more than $12 million achieves an appropriate balance of these important considerations. Therefore, we decline to adopt the Company's proposal or the Attorney General's recommendation.

As noted above, the Company proposes to increase the $10.5 million annual base rate contribution to the storm fund by $8.8 million for a total of $19.3 million (Exhs. NG-RRP-1, at 59, 61-65; NG-RRP-2 (Rev. 4), Sch. 33 at 2, 3; WP NG-RRP-14 (Rev. 4), Sch. 33, at 1; NG-RRP-2 (Rev. 4), Sch. 3, at 2, line 22). The Department finds that the appropriate level of base rate contribution to the storm fund is $16.0 million, which represents an increase of $5.5 million over the test year amount. Accordingly, the Department will reduce the Company's proposed cost of service increase for the annual storm fund contribution by $3.3 million ($8.8 million less $5.5 million).

ii. Recovery of Three Storms Over $30.0 Million

The Attorney General opposes including in the SFRF Winter Storms Riley and Quinn and Tropical Storm Philippe, each of whose incremental net O&M costs (net of deductible and Verizon costs) exceeded $30.0 million (Attorney General Brief at 42-43; Attorney

General Reply Brief at 19-20). In the instant proceeding, the Department has approved the Company's PBR mechanism with a five-year stay-out provision, which precludes the Company from filing a base distribution rate case during that five-year period (see Section II.B.4., above). As a result, the Company no longer has a mechanism (e.g., base distribution rate filing) by which it can seek recovery of costs for storms greater than $30.0 million in a timely manner. In addition, approval of the Company's PBR mechanism represents a change of circumstances that was not a consideration when the Department issued its Order in D.P.U. 15-155. Because of this, the Attorney General's assertion that the Company has sought to defer the costs associated with Winter Storms Riley and Quinn and Tropical Storm Philippe and can recover them in its next base rate case is not a reasonable option for the timely recovery of these costs because the Company's next base rate distribution case will allow for new base distribution rates effective no earlier than October 1, 2024 (Exh. NG-PBRP-1, at 47). Therefore, the SFRF is the only remaining reasonable alternative for the timely recovery of such storm costs. Thus, the Department allows for the final incremental O&M cost accounting of Winter Storms Riley and Quinn and Tropical Storm Philippe through the SFRF, as proposed by the Company.[216]

The Department notes that the final cost accounting related to these three storms has not been finalized. The formal request for authorization to defer the future recovery of costs

---

216 At the time of filing in the instant proceeding, the aggregate (non-final) incremental O&M expenses associated with Winter Storms Riley and Quinn and Tropical Storm Philippe was $99.5 million (Exh. NG-RRP-1, at 60). During the course of the proceedings, the Company updated the total to $111.0 million, with each storm exceeding the $30.0 million storm fund cap (Exh. AG 36-7, Att. at 1).

incurred in these three storms, however, has been filed with the Department in docket D.P.U. 19-38. As the cost recovery related to these storms is approved for recovery through the SFRF pending a prudency review of the actual costs in a future proceeding, the need for the Department to consider the deferral request in D.P.U. 19-38 is rendered moot.

iii. Carrying Charges

While the Company does not seek to modify the carrying charges, it requests that the Department clarify the parameters for recovering carrying charges on storm costs for events with incremental O&M expenses in excess of $30.0 million where there is no finding of deficient performance in restoring power (Exh. NG-RRP-1, at 68, citing D.P.U. 17-05, at 556-557). The Attorney General asserts that the Department should refrain from a decision on the application of carrying charges on deferred storm costs (including when carrying charges begin to accrue) until the Company files with the Department for storm cost recovery and the Department reviews these costs for prudency (Attorney General Brief at 44, citing D.P.U. 17-05, at 556-557; Attorney General Reply Brief at 20). In D.P.U. 17-05, at 556-557, the Department stated that we would consider the recovery of carrying charges for large-scale storms only after an opportunity to fully investigate the circumstances surrounding the incurrence of the costs to which the carrying charges are proposed to be applied.

In D.P.U. 15-155-A at 15-16, the Department determined that it was appropriate to allow National Grid to begin to accrue carrying charges for storm fund eligible storms at the time of cost incurrence. The Department concluded that this finding, in conjunction with other modifications to the Company's storm fund approved in that proceeding, would provide for adequate recovery of storm costs from customers in a manner that was designed to create rate stability. D.P.U. 15-155-A at 15. Upon further consideration of this issue in the instant proceeding, the Department is persuaded that the same rationale should apply to the accrual of carrying charges for large-scale storms, as allowing the Company to accrue carrying charges at the time of cost incurrence for storms greater than $30.0 million strikes an appropriate balance between providing adequate recovery of storm costs and rate stability. Accordingly, for storms with incremental O&M costs exceeding $30.0 million, National Grid is allowed to begin to accrue carrying charges at the prime rate at the time that costs are incurred.

In reaching this decision, the Department emphasizes that the importance of a storm cost filing prudency review of large-scale storms, similar to that of storm fund eligible storms, is not to be overlooked. As such, the Department expects the Company to expedite storm cost filings for its deferred storms for Department review as soon as practicable. In its prudency review, the Department will re-evaluate the reasonableness of the application of carrying charges at the prime rate for storms greater than $30.0 million and, if warranted, calculate appropriate reconciliation carrying charge adjustments to ratepayers if the review of such storm filings do not meet the standards of the Company's emergency response plan. Such carrying charge reconciliations will be premised on the Company's emergency response plan performance (with respect to the specific storms in excess of $30.0 million sought for cost recovery) and the adequacy and completeness of its cost prudency filing materials.

4. Conclusion

Based on the above findings, the Department directs the Company to continue its storm fund with the modifications set forth herein. The modified storm fund shall apply to any qualifying storms that occur after October 1, 2019. The current storm balance shall be recovered through November 2023, consistent with the findings above. Further, the Department directs the Company to file as part of its compliance filing in this proceeding a revised storm fund replenishment provision tariff (Exh. NG-HSG-13, Proposed M.D.P.U. No. 1390 (Bates Stamp 179)). Finally, consistent with the findings above, the Department has adjusted the Company's proposed cost of service by (1) a decrease of $3.3 million relative to the annual base rate contribution to the storm fund and (2) an increase of $200,000 relative to the amount in base distribution rates to recover O&M costs up to the $1.55 million threshold for storms that qualify for the storm fund. The net reduction to the proposed cost of service is a decrease of $3.1 million. These adjustments are shown in Section XIX.B., Schedule 2, below.

XIII. VEGETATION MANAGEMENT PROGRAM

A. Introduction

National Grid's vegetation management program consists of two primary activities – cycle pruning and enhanced hazard tree mitigation (Exhs. NG-VMP-1, at 3-4; AG 14-1, Att. 1). Currently, MECo's circuits are on a five-year pruning cycle, designed to prune every circuit once every five years, while Nantucket Electric's circuits are on a four-year pruning cycle (Exh. NG-VMP-1, at 3).[217] The Company's pruning specifications, which are used by all National Grid contractors, provide for certain minimum distances between all vegetation and power lines (Exh. NG-VMP-1, at 9).[218] The Company's cycle pruning program is designed to maintain an acceptable clearance between overhead conductors and vegetation to minimize the risk to the public and utility workforce (Exhs. NG-VMP-1, at 7-8; AG 14-1, Att. 2).

National Grid proposes four changes to its vegetation management pilot program established in Massachusetts Electric Company/Nantucket Electric Company, D.P.U. 17-92 (2018). First, the Company proposes to change the tariff name to remove the word "pilot" from several locations in the tariff (Exh. NG-HSG-13, Proposed M.D.P.U. No. 1397 (Bates Stamp 263-266)). Second, the Company proposes to transition MECo from a five-year pruning cycle to a four-year pruning cycle and recover any incremental costs through its vegetation management pilot provision (Exhs. NG-VMP-1, at 3-4, 5; NG-HSG-13, Proposed M.D.P.U. No. 1397, § 1.0 (Bates Stamp 263)). Third, National Grid proposes to remove all ash trees in the Company's service territory with known and confirmed infestations of the emerald ash borer and recover any incremental costs through its vegetation management pilot

---

217 The Company's Rhode Island affiliate, The Narragansett Electric Company, operates on a four-year pruning cycle (Exh. NG-VMP-1, at 3-4).

218 The Company's minimum pruning clearance distances are (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 (residential areas) or 15 feet above the conductor in unmaintained properties (rural areas) (Exhs. NG-VMP-1, at 8; AG 14-1, Att. 2).

provision (Exhs. NG-VMP-1, at 12-13; NG-HSG-13, Proposed M.D.P.U. No. 1397, § 1.0 (Bates Stamp 263)). Fourth, National Grid proposes to remove oak trees infested with the gypsy moth and recover any incremental costs through its vegetation management pilot provision (Exhs. NG-VMP-1, at 14, 18; NG-HSG-13, Proposed M.D.P.U. No. 1397, § 1.0 (Bates Stamp 263)). National Grid proposes incremental costs of: (1) $4.5 million annually for implementation of the four-year pruning cycle; (2) $49.0 million for expanded removal of ash trees; and (3) $6.2 million for removal of oak trees (Exhs. NG-VMP-1, at 18; NG-VMP-2; NG-VMP-8).[219]

B. Positions of the Parties

1. Attorney General

The Attorney General maintains that the Department should deny MECo's request to change from a five-year pruning cycle to a four-year pruning cycle (Attorney General Brief at 201; Attorney General Reply Brief at 72). The Attorney General asserts that the Company has provided insufficient evidence to implement the revised pruning cycle for MECo (Attorney General Brief at 201). The Attorney General also asserts that the Company itself had indefinitely postponed a transition to a four-year pruning cycle due to cost concerns (Attorney General Reply Brief at 71-72, citing Tr. 6, at 798). The Attorney General also contends that the Department gave National Grid the opportunity to transition to a four-year

[219] The Company proposes expending (1) $49.0 million for ash tree removal over an eight-year period with annual costs ranging from $1.7 million to $8.9 million and (2) $6.2 million for oak tree removal over a two-year period with annual costs of approximately $3.1 million (Exh. NG-VMP-8).

pruning cycle and the Company declined (Attorney General Brief at 202-203, citing Exh. NG-VMP-1, at 6; Tr. 6, at 772, 798; D.P.U. 17-92, at 15-16). The Attorney General argues that if the Department approves the Company's proposal for transitioning MECo to a four-year pruning cycle, the approval should be conditioned on a reassessment in the Company's next base distribution rate case (Attorney General Brief at 205).

The Attorney General maintains that an expanded tree removal program is necessary, but not at the accelerated pace requested by the Company and not for the gypsy moth infestation (Attorney General Brief at 201). The Attorney General recommends that the Department adopt an expanded hazard ash tree removal for the Company, but reduce the Company's proposed budget by half and extend the removal period to 14 years (Attorney General Brief at 207). The Attorney General argues the Company's oak tree removal plan would result in unnecessary charges to ratepayers and would deprive the Commonwealth of the benefits from otherwise healthy oak trees and, as such, should be rejected (Attorney General Brief at 209).

Finally, the Attorney General asserts that the Company proposes to recover its incremental costs through a new reconciling mechanism, which contradicts the Department's position that these expenses should be included in the Company's cost of service (Attorney General Brief at 202, citing D.P.U. 17-92, at 15-16). The Attorney General also argues that the Company failed to demonstrate the necessary requirements to establish a new reconciling mechanism (Attorney General Brief at 209, citing D.P.U. 10-55, at 66 n.43; D.T.E. 05-27, at 183-186; Boston Edison Company/Cambridge Electric Light Company/Commonwealth

Electric Company/NSTAR Gas Company, D.T.E. 03-47-A at 25-28, 36-37 (2003); Eastern Enterprises/Essex County Gas Company, D.T.E. 98-27, at 6, 28 (1998)). Thus, the Attorney General recommends the Department include any incremental vegetation management expense established in this case in the Company's cost of service and not create another reconciling mechanism (Attorney General Brief at 209).

2. Company

The Company argues that it needs to transition to a four-year pruning cycle for MECo in order to decrease tree-related interruptions (Company Brief at 444). The Company maintains that all other investor-owned utilities in Massachusetts follow a four-year pruning cycle (Company Brief at 444). National Grid contends that it has averaged 2,738 tree-related interruptions per year from 2016 to 2018, which represents an increase of 44 percent when compared to the annual average from 2010 to 2015 (Company Brief at 445). The Company maintains that tree-related outages are increasing and the status quo will not be sufficient to meet the new reliability targets that apply beginning this year (Company Brief at 445). Further, the Company states that consistent cycle pruning helps maintain service reliability, avoiding potential interruptions from phase-to-phase tree contact, and can provide line crews with safe and easy access to power lines (Company Brief at 445). National Grid also maintains that in D.P.U. 17-92, at 15, the Department strongly encouraged the Company to implement a four-year pruning cycle to ensure a sufficiently robust vegetation management program so that customers are served reliably, and to seek cost recovery in a future base distribution rate case (Company Brief at 444-445). Thus, the Company maintains that its proposal to recover the incremental costs related to a four-year pruning cycle is in compliance with the Department's findings in D.P.U. 17-92 (Company Brief at 445).

National Grid asserts that there is no cure for emerald ash borer infestation and that infested trees may not show any outward signs of infestation (Company Brief at 445). Further, the Company claims that ash trees infested with the emerald ash borer have a 100-percent mortality and failure rate (Company Brief at 446). With respect to gypsy moth infestations, the Company estimates that, absent mitigation efforts, oak tree mortality and subsequent failure will result in an increase of service interruptions and millions of dollars in damage to its electric system infrastructure (Company Brief at 447).

The Company maintains that it proposes to collect the proposed costs through the vegetation management pilot provision approved in D.P.U. 17-92 (Company Brief at 449, citing Exh. NG-VMP-1, at 20). The Company maintains that making revisions to the current provision is more effective than creating a new reconciling mechanism (Company Brief at 449).

C. Analysis and Findings

Based on the record in this proceeding, we deny the Company's proposal to revise its vegetation management pilot provision in any manner.[220] The Department approved the vegetation management pilot commencing April 1, 2019 through March 31, 2023.

[220] Contrary to the Attorney General's position, the Company is not seeking to implement an additional reconciling mechanism, but seeks to revise its current tariff to collect additional costs (Exh. NG-HSG-13, Proposed M.D.P.U. No. 1397, § 1.0 (Bates Stamp 263)).

D.P.U. 17-92, Stamp-Approval (September 24, 2018). The Company submitted its base distribution rate case filing on November 15, 2018, less than two months after approval of its pilot and prior to actual commencement of the pilot. Thus, we find that an insufficient period of time has passed to determine whether any changes to the pilot are appropriate.[221]

With respect to approval of costs related to a four-year pruning cycle, in D.P.U. 17-92, the Company proposed a vegetation management pilot with a four-year pruning cycle. The Department authorized the Company's vegetation management pilot, which included a reconciling mechanism that allowed for recovery of certain costs but declined to allow estimated costs related to transitioning to a four-year pruning cycle. D.P.U. 17-92, at 15-16. The Department stated that to the extent that MECo implemented a four-year pruning cycle, the Company "may seek recovery of the test-year expenses with an appropriate showing in a future base distribution rate case." D.P.U. 17-92, at 15-16.

In the instant proceeding, the record shows that National Grid issued requests for bids with the intention of beginning its transition to a four-year pruning cycle on April 1, 2019 (Exh. NG-VMP-1, at 6). The Company states that the bids received were at costs that were "significantly higher than in years past" (Tr. 6, at 772, 798). As such, the Company

---

221 The Company raises some of the same arguments that it presented in D.P.U. 17-92 (compare, e.g., Company Brief at 444-445 and D.P.U. 17-92, at 12 (Company argues more frequent pruning cycle provides numerous benefits); Company Brief at 446 and D.P.U. 17-92, at 28-29 (Company argues that removal of ash trees infected with emerald ash borer will promote system reliability)). Without the experience of more information from the implementation of the vegetation management pilot program, the Company's position appears to be in the nature of an out-of-time motion for reconsideration.

maintained the five-year pruning cycle (Tr. 6, at 772, 798). The Company also testified that it did not know whether or when it will implement a four-year pruning cycle (Tr. 6, at 772, 798). The Company asserts that it is complying with the Department's directive in D.P.U. 17-92 by seeking to recover in this proceeding any incremental costs related to a four-year pruning cycle in its vegetation management pilot provision (Company Brief at 444-445). Such an assertion is in direct conflict with the Department's Order in D.P.U. 17-92, at 15-16, which stated that test-year expenses may be included in the Company's cost of service upon an appropriate showing. Because National Grid has not yet transitioned to a four-year pruning cycle, it has not incurred any costs related to that proposal. As such, there are no costs to include in the Company's test-year cost of service in this proceeding. The currently effective tariff, M.D.P.U. No. 1343, provides for recovery, on a reconciling basis, of actual incremental allowed O&M expenses incurred by the Company during the previous calendar year attributable to its vegetation management pilot. M.D.P.U. No. 1343, §§ 1.0, 2.1. We find no basis to change this cost recovery mechanism.[222] Therefore, we deny the Company's proposal to collect any future anticipated costs through its vegetation management pilot provision. Further, we reiterate that, to the extent that MECo has transitioned to a four-year pruning cycle, the Company may include

---

[222] Based on the Department's evaluation of the Company's vegetation management pilot in D.P.U. 17-92, the Department will determine the most cost-effective vegetation management program and appropriate trim cycle e.g., whether a four-year or five-year trim cycle with mid-cycle pruning is the most prudent. Similarly, determinations for incremental cost recovery for this program will be made through that process in D.P.U. 17-92.

the test-year costs in its cost of service on an appropriate showing in its next base distribution rate case. D.P.U. 17-92, at 15-16.

With regard to the Company's proposal to remove all ash trees within striking distance of its overhead electric distribution and sub-transmission systems over the course of seven years, the Company has conducted an emerald ash borer risk assessment and operational plan; however, the Company has proposed to accelerate the timeframe to eight years for an infestation that is expected to occur over a ten-year to 15-year window (Exh. NG-VMP-1, at 10; Tr. 6, at 780-781). The Department has previously found that ash trees should not be singled out for removal. D.P.U. 17-92, at 33. We do not find substantial evidence to change this finding. The Department reiterates our finding that hazard and risk tree removal shall target hazard trees deemed an imminent threat, as those terms are defined by National Grid for its existing enhanced hazard tree mitigation program, in the Company's condition assessment. D.P.U. 17-92, at 33.[223] The Department again encourages National Grid to coordinate with other agencies and entities in monitoring the emerald ash borer's progress throughout its service territory and take a unified approach to mitigation. D.P.U. 17-92, at 34. Based on these factors, the Department rejects the

223 It appears that National Grid is attempting to expand both the definition of hazard tree and imminent threat as defined by its enhanced hazard tree mitigation program, i.e., a hazard tree is diseased, dying, or dead and is deemed an imminent threat if that tree is likely to fail at any time and needs to be removed immediately. D.P.U. 17-92, at 3 & n.4. Given the recent implementation of its vegetation management pilot program and lack of experience, this proceeding is the inappropriate venue for such expansion.

Company's proposal to revise its vegetation management pilot provision to recover incremental costs related to removal of ash trees in its service territory.

With regard to oak tree removal, the Company has not conducted a gypsy moth risk assessment or a gypsy moth operational plan (Tr. 6, at 790). As such, the Company has not provided any analytical support for removing infested oak trees (Tr. 6, at 788-789). Infested oak trees do not always succumb to the gypsy moth and the Company agreed that the gypsy moth will not kill 100 percent of the oak trees in Massachusetts (Tr. 6, at 790). Thus, it is unclear how many infested oak trees in the Company's service territory pose a certain risk of dying and striking the Company's electric infrastructure. Therefore, the Department rejects the Company's proposal to revise its vegetation management pilot provision to include recovery of incremental costs related to removal of oak trees infested by the gypsy moth.

XIV. CAPITAL STRUCTURE AND RATE OF RETURN

A. Introduction

National Grid proposed an 8.04-percent WACC representing the rate of return to be applied on rate base to determine the Company's total return on its investment (Exhs. NG-RBH-1, at 64; NG-RBH-10, at 1).[224] The Company's WACC is based on the following proposed elements: (1) capital structure that consists of 46.43 percent long-term debt, 0.08 percent preferred stock, and 53.49 percent common equity; (2) cost of long-term

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

debt of 5.22 percent; (3) cost of preferred stock of 4.44 percent; and (4) ROE[225] of 10.50 percent (Exhs. NG-RBH-1, at 64; NG-RBH-10, at 1; NG-RBH-Rebuttal-1, at 106). The Company based its proposed ROE on quantitative and qualitative analyses relying on three approaches: (1) the discounted cash flow ("DCF") model, including the constant growth and multi-stage forms; (2) the capital asset pricing model ("CAPM") and empirical CAPM ("ECAPM"); and (3) the bond yield plus risk premium method ("risk premium model") (Exhs. NG-RBH-1, at 2-3; NG-RBH-Rebuttal-1, at 104).

The Attorney General proposed a WACC of 6.92 percent (Exh. AG-JRW at 5, Table 1). The Attorney General's WACC is based on the following proposed elements: (1) capital structure that consists of 51.78 percent long-term debt, 0.09 percent preferred stock, and 48.13 percent common equity; (2) cost of long-term debt of 5.22 percent; (3) cost of preferred stock of 4.44 percent; and (4) ROE of 8.75 percent (Exhs. AG-JRW at 4-5; AG-JRW-1, at 1). The Attorney General proposed an alternate WACC of 7.03 percent based on: (1) the Company's proposed capital structure; (2) a cost of long-term debt of 5.22 percent; (3) a cost of preferred stock of 4.44 percent; and (4) a proposed ROE of 8.60 percent (Exhs. AG-JRW at 5-6; AG-JRW-1, at 1).

Below, we examine (1) the Company's capital structure, cost of debt, and cost of preferred stock; (2) the proxy group selections used by the parties in supporting their proposed ROEs; and (3) the appropriate ROE.

---

225 The terms ROE and cost of equity are used interchangeably throughout this Section.

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 restructuring finance plan, removing goodwill, and removing debt associated with undersea cables (Exhs. NG-RBH-1, at 66; NG-RBH-10, at 2). As of December 31, 2017, the end of the test year, MECo's recorded capital structure consisted of $1,298,051,000 in long-term debt, $2,259,000 in preferred stock, and $2,531,131,000 in common equity (Exh. NG-RBH-10, at 2). As of that same date, Nantucket Electric's recorded capital structure consisted of $51,300,000 in long-term debt and $61,199,000 in common equity (Exh. NG-RBH-10, at 2). The combined balances amount to $1,349,351,000 in long-term debt, $2,259,000 in preferred stock, and $2,592,330,000 in common equity (Exh. NG-RBH-10, at 2).[226]

National Grid has incorporated proposed changes to the test-year-end capitalization balances for both MECo and Nantucket Electric. MECo's pro forma long-term debt balance of $1,300,000,000 restores $1,949,000 in unamortized debt issuance expenses that MECo excludes from long-term debt for financial reporting purposes (Exhs. NG-RBH-1, at 66; NG-RBH-10, at 2). MECo's pro forma common equity balance of $1,517,483,000 incorporates the removal of $1,013,648,000 in goodwill and accumulated other comprehensive income (Exhs. NG-RBH-1, at 66; NG-RBH-10, at 2).

---

226 Nantucket Electric did not have preferred stock.

Nantucket Electric's adjusted long-term debt balance of zero 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 (Exh. NG-RBH-10, at 2). Nantucket Electric's adjusted common equity balance of $45,367,000 incorporates the removal of $15,831,000 of goodwill and accumulated other comprehensive income (Exhs. NG-RBH-1, at 66; NG-RBH-10, at 2).

Based on these adjustments, National Grid proposes a capital structure for the combined MECo and Nantucket Electric operations consisting of $1,300,000,000 in long-term debt, $2,259,000 in preferred stock, and $1,497,850,000 in common equity that has been further adjusted to reflect a dividend payment from MECo to National Grid USA of $65,000,000,[227] for a total capitalization of $2,800,109,000 (Exhs. NG-RBH-10, at 2; DPU-NG 19-30). These balances produce a capital structure consisting of 46.43 percent long-term debt, 0.08 percent preferred stock, and 53.49 percent common equity (Exhs. NG-RBH-1, at 69; NG-RBH-10, at 2; NG-RBH-Rebuttal-1, at 106). The Company proposes a rate of 5.22 percent for its long-term debt and 4.44 percent for its preferred stock (Exhs. NG-RBH-1, at 68-69; NG-RBH-10, at 1).

227 The Company's restructuring finance plan consisted of MECo's dividend payment of $65 million to National Grid USA on December 27, 2018, to align the MECo equity ratio with its target capital structure (Exh. DPU-NG 19-30). The dividend was approved by MECo's Board of Directors on December 19, 2018 (Exh. DPU-NG 19-30).

2. Attorney General Proposal

The Attorney General proposed a capital structure consisting of 51.78-percent long-term debt, 0.09-percent preferred stock, and 48.13-percent common equity (Exhs. AG-JRW at 4; AG-JRW-3, at 1). The Attorney General imputed this capital structure by using the average common equity of the Company's proxy group and adjusting the long-term debt and preferred stock proportionally (Exh. AG-JRW at 28). The Attorney General contends that equity capital is more expensive than debt and adds to a company's income tax burden, which raises utility rates for customers (Exh. AG-JRW at 26). Therefore, by imputing the capital structure, the Attorney General seeks to align the Company's capital structure with that of the proxy group (Exh. AG-JRW at 28).

Alternatively, the Attorney General proposed to adopt the capital structure proposed by the Company and make a 15-basis-point adjustment to the ROE to account for reduced financial risk (Exh. AG-JRW at 29). She contends that the adjustment reflects the lower financial risk inherent with the Company's lower debt to equity ratio compared to the proxy group (Exh. AG-JRW at 29). The 15-basis-point adjustment is based on the yield differential between A3 and Baa1 Standard and Poor's Financial Services, LLC ("S&P") issuer credit ratings, which are equivalent to issuer credit ratings of A- and BBB+ by Moody's Investors Service, Inc. ("Moody's) (Exh. AG-JRW at 21, 29, 97-98). The Attorney General adopted the cost of debt and cost of preferred stock proposed by the Company for her analysis (Exh. AG-JRW at 4, 29).

3. Positions of the Parties

a. Attorney General

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 68, 69, Tables 1, 2). The Attorney General 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 68). The Attorney General asserts that the Company's debt to equity ratio is lower than that of the proxy group and, therefore, the Company has less financial risk (Attorney General Brief at 69). The Attorney General argues that by applying an allowed ROE derived using a proxy group with a higher debt level to the Company's capital structure overstates the Company's cost of capital (Attorney General Brief at 69).

As an alternative, the Attorney General proposed a capital structure that reflects the capital structure of the proxy groups and National Grid plc (Attorney General Brief at 70).[228] The Attorney General argues that if the Department uses the Company's proposed capital structure of 46.43-percent long-term debt, 0.08-percent preferred stock and 53.49-percent common equity, the Department should account for the reduced financial risk by lowering the allowed ROE by 15 basis points (Attorney General Brief at 69). The Attorney General predicates her risk adjustment of 15 basis points on the difference between the average long-term yields utility bonds rated A3 (the Company's bond rating) and the lower Baa1 (the

---

[228] The Company is a wholly owned subsidiary of National Grid USA, which is an indirect wholly owned subsidiary of National Grid plc (Exhs. NG-MLR-1 at 18; AG 1-2, Att. 4, at 12).

average bond rating of the companies in both the Company's and the Attorney General's proxy groups) (Attorney General Brief at 69, citing Exh. AG-JRW-1, at 2).

b. Company

The Company argues that the Attorney General's recommended hypothetical capital structure violates Department precedent (Company Brief at 301; Company Reply Brief at 12). Additionally, the Company contends that the capital structure it relies on in its analysis is consistent with the equity capitalization ratios of other comparable companies (Company Brief at 302, citing Exhs. NG-RBH-Rebuttal-1, at 21; NG-RBH-Rebuttal-9; Company Reply Brief at 12). It asserts that the Company's common equity ratio of 53.49 percent is well within the range of the median common equity ratio of its proxy group of 52.88 percent (Company Brief at 302, citing Exh. NG-RBH-Rebuttal-9). National Grid further disputes the Attorney General's position by stating that the capitalization ratios of the Company's proxy group members are at the holding company level, rather than at the operating level, which operate differently and have different types of assets (Company Brief at 302). National Grid also contends that some of the companies in the Attorney General's proxy group are in jurisdictions that include cost-free capital components and tax-credit balances not available in Massachusetts (Company Brief at 303). Finally, the Company argues that the Attorney General's comparison of the Company to its parent company is irrelevant as it is a widely accepted regulatory practice to treat distribution companies as stand-alone entities (Company Brief at 303, citing Exh. NG-RBH-Rebuttal-1, at 25; D.P.U. 13-75, at 275-276).

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 the company's rate base as part of the revenue requirement established by the Department, and is made up of three components: (1) the cost of the Company's long-term debt; (2) the cost of the Company's preferred stock; and (3) the ROE set 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; Colonial Gas Company, D.P.U. 84-94, at 50 (1984). 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).

No party contested the Company's reversal of $1,949,000 in unamortized debt issuance expense that it had credited against its long-term debt securities. 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; Boston Edison Company, D.P.U. 86-71, at 12 (1986). 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 $1,029,479,000[229] in goodwill and accumulated other comprehensive income. 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 "outstanding stock" as

---

229 Of the $1,029,479,000 in goodwill and accumulated other comprehensive income, $1,013,648,000 is attributable to MECo and $15,831,000 to Nantucket Electric (Exh. NG-RBH-10, at 2).

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-RBH-1, at 66; NG-RBH-10, at 2).[230] 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.

Turning to the dividend payment of $65,000,000 from MECo to National Grid USA, the Department recognizes that its purpose was to achieve a target for its capital structure and finds that it represents a known and measurable change to test-year-end capitalization. (Exh. DPU-NG 19-30). Within a broad range, the Department will defer to the management of a utility in decisions regarding the appropriate capital structure, and normally accept the utility's test-year-end capital structure unless the capital structure deviates substantially from sound utility practice. D.T.E. 03-40, at 319; D.P.U. 1360, at 26-27; D.P.U. 1135, at 4. See also D.P.U. 20104, at 42; New England Telephone and Telegraph Company v.

230 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. 551.

Department of Public Utilities, 327 Mass. 81, 90-91 (1951). Accordingly, the Department accepts this proposed adjustment to the Company's common equity balance.

Notwithstanding our acceptance here, the Department recognizes that a dividend payment to the parent company is not subject to regulatory review under a discernible standard. For example, stock issuances by the Company would be subject to the test under G.L. c. 164, § 14, as to whether the contributions were reasonably necessary to accomplish some legitimate purpose in meeting a company's service obligations. Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 395 Mass. 836, 841-842 (1985), citing Fitchburg Gas and Electric Light Company v. Department of Public Utilities, 394 Mass. 671, 678 (1985). The reduction to the common equity balance at a subsidiary outside of the regulatory review process could have consequences where the adjustment to the subsidiary's capital structure results in a higher financial risk. We address the incidence of financial risk below.

Based on the foregoing analysis, the Department uses a long-term debt balance of $1,300,000,000, a preferred stock balance of $2,259,000, and a common equity balance of $1,497,850,000 to determine National Grid's capital structure. As shown on Schedule 5 of this Order in Section XVIII.F., below, the use of these balances produces a capital structure consisting of 46.43 percent long-term debt, 0.08 percent preferred stock, and 53.49 percent common equity, which we consider to be consistent with sound utility practice.[231]

---

[231] We find that the Attorney General's proposed capital structure based on imputed averages from both the Company's and her proxy groups is not appropriate in this circumstance and is inconsistent with Department precedent regarding use of a

b. Cost of Debt and Preferred Stock

The Attorney General adopted the Company's recommended long-term debt and preferred stock cost rates of 5.22 percent and 4.44 percent, respectively (Exh. AG-JRW at 4). No other party commented on the proposed rates. 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. D.P.U. 92-78, at 91-92; D.P.U. 90-121, at 160-161. The issuances of the outstanding long-term debt preceded the Company's last base distribution rate case filing (Exh. NG-RBH-10). The Company's effective cost of long-term debt and preferred stock is consistent with the 5.21 percent and 4.44 percent that was approved in its last base distribution rate case proceeding. D.P.U. 15-155, at 348. 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.

---

test-year-end capital structure. D.P.U. 15-155, at 343, 346; D.P.U. 15-80/D.P.U. 15-81, at 250, 253; D.P.U. 14-150, at 315; see also 359 Mass. 420, 429.

C. Proxy Groups

1. Company Proxy Group

As stated above, National Grid is an indirect subsidiary of National Grid plc; National Grid is not publicly traded (Exhs. NG-MLR-1, at 18; NG-RBH-1, at 15). Therefore, there is no public market for the Company's stock. Accordingly, National Grid presents its ROE analysis using the capitalization and financial statistics of a proxy group of 24 electric companies (Exhs. NG-RBH-1, at 16-19; NG-RBH-9; NG-RBH-Rebuttal-1, at 104 & n.236).[232] The Company selected its proxy group from a group of 39 companies classified as electric utilities by Value Line Investment Survey ("Value Line") (Exh. NG-RBH-1, at 16-17). From that group, National Grid chose companies that (1) have consistently paid quarterly dividends, (2) have been covered by at least two utility industry equity analysts, (3) have investment grade senior unsecured bond and/or corporate credit ratings from S&P, (4) received at least 60 percent of their operating income from regulated electric utility operations over the past three fiscal years, (5) have reported operating income over the three most recent fiscal years representing at least 60 percent of total regulated operating income, and (6) are not known to be part of a significant or transformative transaction (Exh. NG-RBH-1, at 16-17). The Company states that the selection criteria employed is consistent with those previously approved by the Department (Exh. NG-RBH-1, at 20, citing D.P.U. 17-05, at 641).

[232] National Grid's proxy group initially consisted of 23 electric companies; the Company subsequently added Evergy, Inc. to the proxy group (Exh. NG-RBH-Rebuttal-1, at 104).

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 28 publicly held electric companies, as well as the Company's own proxy group (Exhs. AG-JRW at 19-20; AG-JRW-2). The Attorney General chose companies that: (1) have at least 50 percent of revenues from regulated electric operations as reported in the U.S. Securities and Exchange Commission's ("SEC") Form 10-K;[233] (2) are classified as an electric utility by Value Line; (3) have an investment grade corporate credit and bond rating from S&P or Moody's; (4) have paid a cash dividend in the past six months, with no reductions or omissions; (5) have not been involved in an acquisition of another utility or the target of an acquisition; and (6) have analysts' long-term EPS growth rate forecasts available from Yahoo! Finance, Thomson Reuters Corporation ("Reuters"), and/or Zack Investment Research, Inc. ("Zack") (Exh. AG-JRW at 19). On an overall basis, the Attorney General's resulting proxy group (1) receive 85 percent of their revenues from regulated electric operations, (2) have a BBB+ bond rating from S&P and a Baa1 Moody's bond rating, (3) have a current mean common equity ratio of 45.2 percent, and (4) have an earned ROE of 9.7 percent (Exhs. AG-JRW at 20; AG-JRW-2).

[233] 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.

3. Positions of the Parties

a. Attorney General

The Attorney General asserts that she conducted her analysis on her own proxy group as well as the proxy group provided by the Company (Attorney General Brief at 77, citing Exh. AG-JRW at 19-21). She contends that based on five different metrics published by Value Line, including beta, financial strength, safety, earnings predictability, and stock price stability, the two proxy groups are very similar in risk (Attorney General Brief at 79). She argues that the Company is less risky than the two proxy groups given the Company's better credit ratings from S&P and Moody's (Attorney General Brief at 79). In addition, she maintains that Value Line's risk ratings of the two proxy groups suggest that electric utility companies are very low risk (Attorney General Brief at 79).

b. Company

The Company asserts that the objective in selecting a proxy group is to develop a group of companies that are fundamentally similar with respect to operating, financial, and business risks of the Company (Company Brief at 289, citing D.P.U. 08-35, at 176. National Grid argues that its proxy group consisting of 23 companies selected from Value Line have been found comparable by the Department to other Massachusetts electric distribution companies in recent years (Company Brief at 289, citing D.P.U. 10-70, at 246-247, 249; D.P.U. 15-80/D.P.U. 15-81, at 260; D.P.U. 15-55 at 348-349, 353-354; D.P.U. 17-05, at 641). In addition, the Company contends that many of the companies in its proxy group have revenue decoupling mechanisms, alternative regulation, and formula-based rate plans (Company Brief at 289-290, citing Exhs. NG-RBH-1, at 47-48; NG-RBH-9).

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; D.P.U. 1300, at 97. 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; Boston Gas Company, D.P.U. 1100, at 135-136 (1982). Rather, we may rely on an analysis that employs valid criteria to determine which companies will be in the proxy group, and that provides sufficient financial and operating data to discern the investment risk of 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 National Grid and the Attorney General each employed a set of valid criteria to select their respective proxy groups, and that 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. D.P.U. 12-25, at 402; D.P.U. 09-30, at 307. Therefore, the Department will accept the use of both proxy groups to assist the Department in determining the Company's fair and reasonable cost of equity.

In our acceptance of these groups, we identify several factors that the Department will take into consideration in determining the ROE for the Company. First, as discussed below, both National Grid and the proxy group members have a number of reconciling mechanisms. The extent to which these particular reconciling mechanisms affect a company's cash flow will affect the evaluation of National Grid's comparability to the proxy groups. Second, some of the holding companies in the proxy groups are also involved in non-regulated businesses beyond energy distribution activities (Exhs. NG-RBH-9; AG-JRW at 96; AG-JRW-2). All else being equal, these business activities potentially increase the business risk to these companies and make them potentially more profitable than the Company. D.P.U. 11-01/D.P.U. 11-02, at 385; D.P.U. 10-114, at 300; D.P.U. 09-30, at 308; D.P.U. 07-71, at 135. Third, the Company's capital structure includes a higher equity component than the average of each of the proxy groups potentially affecting the relative financial risk of the Company (Exhs. AG 7-17, at 1-2; AG-JRW at 22-23; AG-JRW at 1). Therefore, while we accept National Grid's and the Attorney General's proxy groups as a basis for evaluating their ROE proposals, we also consider the particular characteristics of the Company as compared to members of the proxy groups when determining the allowed ROE.

D. Return on Equity

1. Company Proposal

In determining its proposed ROE, the Company relied on the DCF model, including constant growth and multi-stage variations, CAPM, ECAPM, and the risk premium model (Exhs. NG-RBH-1, at 3; NG-RBH-3; NG-RBH-4; NG-RBH-5; NG-RBH-7; NG-RBH-8; NG-RBH-Rebuttal-1, at 104; NG-RBH-Rebuttal-2 through 7). These models were applied to market and financial data developed from its proxy group and updated with data as of March 15, 2019 (Exhs. NG-RBH-1, at 10-15, 27, 34; NG-RBH-Rebuttal-1, at 104). Based on the results of these models and the Company's evaluation of its business risks relative to its proxy group, National Grid determined that its ROE is in the range of 10.00 percent to 10.75 percent (Exhs. NG-RBH-1, at 2; NG-RBH-Rebuttal-1, at 106).

The Company stated that its proposed ROE takes into account the implementation of revenue decoupling mechanisms, reconciling cost recovery mechanisms, its PBR mechanism, and the impact of the 2017 Tax Act, as well as the Company's particular business risks, and additional qualitative considerations to which the Department has previously given weight in establishing authorized returns (Exh. NG-RBH-1, at 45-54). National Grid did not make an adjustment to the proposed ROE for its the revenue decoupling mechanism or proposed PBR mechanism, stating that revenue stabilization and cost recovery structures have become increasingly common and, therefore, there is no reason to believe that, with a revenue decoupling mechanism and a PBR mechanism, the Company is less risky than its peers (Exh. NG-RBH-1, at 46-48, citing, e.g., Adjustment Clauses: A State-by-State Overview, Regulatory Research Associates Regulatory Focus, September 28, 2018). In addition, the Company states that the "stay-out" period provision in the PBR mechanism would prevent it from seeking recovery of higher capital costs and would, therefore, make it more risky (Exh. NG-RBH-1, at 49).

The Company also states that it has considered the effects of the 2017 Tax Act, noting that ratings agencies have observed a reduction in revenue and the potential requirement of returning excess deferred income tax associated with the 2017 Tax Act (Exh. NG-RBH-1, at 51, citing S&P Global Market Intelligence, Rating Agencies Warn Tax Reform Could Drag US Utility Sector Credit Quality, January 25, 2018). National Grid states that Moody's expects the debt to total capitalization ratios to increase based on the reduced value of deferred tax liabilities, and, on that basis, National Grid concludes that the implications of the 2017 Tax Act support the proposed ROE range and recommendation (Exh. NG-RBH-1, at 52-54, citing Moody's, Rating Action: Moody's Changes Outlooks on 25 U.S. Regulated Utilities Primarily Impacted by Tax Reform, January 19, 2018).

2. Attorney General Proposal

In determining her proposed ROE, the Attorney General relies on the constant growth DCF and the CAPM models (Exhs. AG-JRW at 4, 36-37; AG-JRW-7; AG-JRW-8). These models were applied to market and financial data developed from both her proxy group and the proxy group used by the Company (Exhs. AG-JRW at 4; AG-JRW-1). Additionally, in her analysis, using the Company's capital structure, the Attorney General makes an adjustment to the cost of equity to reflect a reduced financial risk associated with the

Company's lower debt to total capitalization ratio (Exhs. AG-JRW at 4, 28; AG-JRW-1). Based on the results of the Attorney General's DCF and CAPM models and an evaluation of the financial and business risks of the Company relative to both the Attorney General's and the Company's proxy groups, the Attorney General determined that an appropriate ROE is 8.75 percent using a capital structure based on the proxy group's average common equity ratio,[234] and 8.60 percent using the Company's capital structure (Exhs. AG-JRW at 4, 5, 29; AG-JRW-1).

In addition, the Attorney General considers the Company's revenue decoupling mechanism and proposed PBR mechanism (Exh. AG-JRW at 95-98). The Attorney General notes that none of the companies in the proxy groups have both a revenue decoupling mechanism and PBR mechanism and that, unlike the proxy groups, at least 96 percent of the Company's revenues are affected by the revenue decoupling mechanism and proposed PBR (Exh. AG-JRW at 95-98). The Attorney General contends that the Company's higher credit ratings from S&P and Moody's than those of the proxy group reflects a lower risk for the Company in part due to these two mechanisms (Exh. AG-JRW at 6, 97-98).

In addition, the Attorney General considered current capital market conditions (Exh. AG-JRW at 6-7, 10-15). She notes that the yield on a 30-year U.S. Treasury bond has remained in the range of 2.8 percent to 3.3 percent over the last two years despite the fact

234 For purposes of this recommendation, the Attorney General relied on the average common equity ratio of the Company's proxy group of 48.13 percent, and the Attorney General adjusted both the long-term debt and preferred stock ratios to match the capital structure and equity cost rate (Exh. AG-JRW at 4).

that short-term Federal funds rates have increased from near zero to about 2.5 percent (Exh. AG-JRW at 11-12). The Attorney General points out that, while the U.S. Federal Reserve System can directly affect short-term borrowing rates through adjustments to the Federal funds rate, U.S. Treasury long-term rates are market driven and based on expectations of economic growth and inflation (Exh. AG-JRW at 12). In addition, she notes that economists' projections are generally skewed toward rising interest rates (Exh. AG-JRW at 13-14). Therefore, the Attorney General recommends that the cost of equity be set using the current market costs rather than speculation about what future conditions may be (Exh. AG-JRW at 13).

The Attorney General notes that allowed ROEs for gas and electric distribution companies have been in decline nationally (Exh. AG-JRW at 16). The Attorney General states that allowed ROEs for electric utilities have steadily declined from an average of 10.01 percent in 2012 to 9.55 percent in 2018 (Exh. AG-JRW at 16, citing Regulatory Focus, Regulatory Research Associates, January 2019). The Attorney General attributes the decline to historically low interest rates and capital costs (Exh. AG-JRW at 16). In addition, she notes that the allowed ROEs for electric distribution companies has been consistently below those of vertically integrated companies by 30 to 50 basis points, stating that the average allowed ROE for electric distribution companies in 2018 was 9.38 percent (Exh. AG-JRW at 17).

3. Discounted Cash Flow Model

a. Company Proposal

The DCF model is based on the premise that a stock's current price represents the present value of all expected future cash flows that investors expect to receive (Exh. NG-RBH-1, at 22). The Company employed both constant growth and multi-stage variations of the DCF model (Exhs. NG-RBH-1, at 3, 6, 22, 33, 71; NG-RBH-3; NG-RBH-4). The constant growth DCF model comprises a forward-looking dividend yield component and an expected dividend growth rate into perpetuity (Exh. NG-RBH-1, at 23). The model assumes that: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant; (3) the price to earnings multiple[235] remains constant in perpetuity; (4) the estimated cost of equity is greater than the expected growth rate; and (5) the calculated cost of equity remains constant, also in perpetuity (Exh. NG-RBH-1, at 23). The Company determined the dividend yield based on the current annualized dividend and average closing stock prices for its proxy companies, over the 30-, 90-, and 180-trading day periods as of March 15, 2019 based on data from Bloomberg Professional Services ("Bloomberg ") (Exhs. NG-RBH-1, at 24, 27-28; NG-RBH-Rebuttal-2, at 1-3). For the expected growth rate, the Company used a consensus of Zacks, Thomson Reuters First Call ("First Call"), and Value Line surveys to estimate a

235 The price to earnings multiple compares a company's current common stock price to its reported net earnings; it also is referred to as the price to earnings ratio.

long-term earnings growth rate of 5.52 percent (Exhs. NG-RBH-1, at 28; NG-RBH-Rebuttal-2, at 1-3).

To address what it contends are certain simplifying assumptions underlying the constant growth model, the Company also used a multi-stage DCF model (Exh. NG-RBH-1, at 31). Similar to the constant growth DCF model, the cost of equity is determined as the present value of future cash flows, however, in the multi-stage DCF model, the growth rate is specified over three distinct stages (Exh. NG-RBH-1, at 32).[236] In each of the three stages, the cash flow, or dividend, is the product of the projected EPS and the expected dividend payout ratio (Exh. NG-RBH-1, at 32). The Company calculated a long-term growth rate of 5.45 percent, based on the long-term real gross domestic product ("GDP")[237] growth rate from 1929 through 2017 of 3.22 percent, plus an inflation rate of 2.16 percent 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 (Exh. NG-RBH-1, at 35-36). The Company updated the long-term growth rate to 5.35 percent as part of its rebuttal testimony (Exh. NG-RBH-Rebuttal-3).

---

236 Under the Company's multi-stage DCF model, the subject company's stock price is set equal to the present value of future cash flows received over three "stages" (Exh. NG-RBH-1, at 32). In the first two stages, cash flows are defined as projected dividends, and 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-RBH-1, at 32).

237 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.

The Company's constant growth DCF model produced a cost of equity mean range of 8.80 percent to 8.99 percent (Exhs. NG-RBH-Rebuttal-1, at 105, Table 6; NG-RBH-Rebuttal-2). National Grid's multi-stage DCF model produced a cost of equity mean range of 8.75 percent to 8.96 percent (Exhs. NG-RBH-Rebuttal-1, at 105, Table 6; NG-RBH-Rebuttal-3).

b. Attorney General Proposal

The Attorney General relies on a constant growth DCF model, claiming that the public utility business is in the steady state (or constant growth) stage of a three-stage DCF model (Exh. AG-JRW at 39-40).[238] To determine the cost of equity using her constant growth DCF model, the Attorney General summed the estimated dividend yield and growth rates of both her proxy group and the Company's proxy group (Exh. AG-JRW at 39). The dividend yield is obtained by dividing the annualized expected dividend in the coming quarter by the current stock price (Exh. AG-JRW at 41). To annualize the expected dividend, the Attorney General multiplied the expected dividend for the coming quarter by four and multiplied the result by one-half of the expected growth rate (Exh. AG-JRW at 41). The Attorney General calculated the DCF dividend yield for the proxy groups using the current

238 The Attorney General's three-stage model is based on: (1) a growth stage characterized by rapidly expanding sales, high profit margins, and an abnormally high growth in EPS; (2) a transition stage in later years, characterized by increased competition with lower profits and slower earnings growth that results in larger earnings payouts in the form of dividends; and (3) a maturity or steady-state stage, where new investment opportunities offer on average only slightly more attractive ROEs, and where the earnings growth rate, payout ratio, and ROE stabilize for the remainder of the firm's life (Exh. AG-JRW at 38-39).

annual dividend and the 30-day, 90-day, and 180-day average stock prices (Exhs. AG-JRW at 41; AG-JRW-7, at 2). Using this method, the mean and median dividend yields for the Attorney General's proxy group range from 3.2 percent to 3.4 percent (Exhs. AG-JRW at 41; AG-JRW-7, at 2). Within this range, the Attorney General chose the mean of 3.30 percent as the dividend yield for her proxy group (Exhs. AG-JRW at 41; AG-JRW-7, at 1). The corresponding mean and median dividend yields for the Company's proxy group ranged from 3.1 percent to 3.4 percent, from which she used 3.3 percent as the dividend yield (Exhs. AG-JRW at 41; AG-JRW-7).

In developing the expected growth rate, the Attorney General relies on the historic and projected growth rates of EPS, dividends per share, and book value per share provided by Value Line and the EPS growth forecasts of Wall Street analysts provided by Yahoo! Finance, First Call, and Zacks (Exhs. AG-JRW at 43; AG-JRW-7). In addition, the Attorney General assessed the prospective growth as measured by prospective earnings and earned returns on common equity (Exh. AG-JRW at 43). Although the Attorney General assumes that EPS and dividends per share will exhibit similar growth rates over the very long term, she relies on historic and projected dividends per share and book value per share as well as internal growth to balance what she states are the shortcomings of relying solely on EPS as a proxy (i.e., an upward bias among Wall Street analysts) (Exh. AG-JRW at 46-47). Giving primary weight to projected EPS growth rates, the Attorney General uses a projected growth rate in the DCF model of 5.00 percent for her proxy and 5.375 percent for the Company's proxy group (Exhs. AG-JRW at 50; AG-JRW-7, at 1).

The Attorney General added the adjusted dividend yields and the estimated growth rates to determine a cost of equity for both her proxy group and the Company's proxy group (Exhs. AG-JRW at 51; AG-JRW-10, at 1; AG-JRW-7). The DCF analysis performed by the Attorney General yields a cost of equity of 8.40 percent and 8.75 percent for her proxy group and the Company's proxy group, respectively (Exhs. AG-JRW at 51; AG-JRW-7).

c. Positions of the Parties

i. Attorney General

The Attorney General asserts that there are several errors with National Grid's DCF analysis (Attorney General Brief at 72, 81-82). First, the Attorney General argues that the Company's analysis has given little weight to its constant growth DCF results (Attorney General Brief at 72, 81-82). Second, she argues that the Company relies exclusively on the upwardly biased EPS growth rate forecasts of financial market analysts (Attorney General Brief at 73, 81-82). The Attorney General argues that the terminal growth rate of 5.45 percent, employed in the Company's multi-stage DCF model, is unsupported by theoretical or empirical evidence, not reflective of economic growth in the United States, and about 100 basis points above projections of long-term GDP growth (Attorney General Brief at 72, 81-83). The Attorney General also argues that the Company is inconsistent in its use of historic versus projected data in its DCF analysis (Attorney General Brief at 85).

The Attorney General notes that the mean equity cost rates are only 8.90 percent in the Company's updated DCF analysis (Attorney General Brief at 82, citing Exh. AG-JRW at 72-73). She states that the Company has given that result very little, if any, weight because if it had, the cost of equity recommendation would have been much lower (Attorney General Brief at 82, citing Exh. AG-JRW at 72-73).

The Attorney General maintains that the Company's analysis is flawed because it relies exclusively on the overly optimistic and upwardly biased EPS growth estimates of Wall Street analysts (Attorney General Brief at 73, 81, 82, citing Exh. AG-JRW at 73-74). She contends that she has provided sufficient empirical evidence demonstrating the bias (Attorney General Brief at 82, citing Exh. AG-JRW at 73-74). She argues that long-term earnings growth forecasts are not more accurate at forecasting future earnings than "naïve random walk forecasts" and lead to an upward bias in cost of equity of almost 3.0 percentage points when used in DCF analysis (Attorney General Brief at 82, citing Exh. AG-JRW at 73-74).

With respect to the Company's multi-stage DCF model, the Attorney General argues that it relies on an inflated long-term GDP growth rate of 5.45 percent as the terminal growth rate for the model (Attorney General Brief at 73, 82). She maintains that the Company has provided no theoretical or empirical support that long-term GDP growth is a reasonable proxy for the expected growth rate of the proxy group (Attorney General Brief at 83). The Attorney General argues that five- and ten-year historic measures of earnings and dividend growth for electric companies suggest that the growth rate is overstated by more than 100 basis points (Attorney General Brief at 83, 85, citing Exh. AG-JRW-10, at 3). Furthermore, she argues that the Company's projected GDP growth also is overstated by approximately 100 basis points (Attorney General Brief at 83, citing Exh. AG-JRW at 75-76). The Attorney General claims that a GDP growth rate of 4.0 percent to 5.0 percent would be appropriate for today's U.S. economy and would be in line with the long-term forecasts of economists and government agencies, including the U.S. Energy Information Administration forecast of 4.3 percent, the Congressional Budget Office forecast of 4.0 percent, and the Social Security Administration forecast of 4.4 percent (Attorney General Brief at 84-85, citing Exh. AG-JRW at 77-78). The Attorney General notes that because of both lower real GDP growth and lower inflation, nominal GDP growth rates have been in decline over the past five decades (Attorney General Brief at 83).

Finally, the Attorney General argues that the Company inconsistently used historical data and forecasts (Attorney General Brief at 85). She notes that the Company relies on forecasts of long-term EPS growth in the constant growth DCF formula, while employing historic data going back to 1929 to develop a terminal growth rate for the multi-stage DCF model (Attorney General Brief at 85). The Attorney General argues that the Company ignored well-known, long-term GDP growth rate forecasts in the multi-stage DCF model (Attorney General Brief at 85, citing Exh. AG-JRW at 65-66, 79).

ii. Company

National Grid argues that the Attorney General's DCF calculation is flawed and should be rejected (Company Brief at 304). The Company claims that the Attorney General's approach is subjective and not replicable (Company Brief at 304, citing Exh. NG-RBH-Rebuttal-1, at 41). National Grid asserts that the Attorney General's DCF recommendation improperly relies on dividend-per-share and book-value-per-share growth rates, which the Company contends are merely derivatives of earnings growth (Company

Brief at 304, citing Exh. NG-RBH-Rebuttal-1, at 41, 48-49). The Company disputes the Attorney General's claim that the Company gave insufficient weight to the results of its constant growth DCF analysis (Company Brief at 304). National Grid argues that the Attorney General has improperly adjusted the DCF calculation downward to account for what she erroneously alleges is an upward bias (Company Brief at 304). In addition, the Company argues that the Attorney General's criticism of terminal growth rate used in its multi-stage DCF analysis should be rejected (Company Brief at 306).

The Company denies that it has underweighted the constant growth DCF model (Company Brief at 304-305). National Grid maintains that one limiting assumption of the model is that the price to earnings ratio is held constant (Company Brief at 305). National Grid argues that because price-to-earnings ratios for utilities have recently been in excess of their historical averages, it is appropriate to give the model less weight (Company Brief at 305). The Company also argues that the Department has recognized the limitations of the constant growth DCF model and has stated that all DCF estimates should be considered (Company Brief at 305).

With respect to the Company's reliance on EPS forecasts of financial market analysts, the Company argues that it is the appropriate measure of growth for the DCF model (Company Brief at 305). National Grid contends that the Attorney General's claims of overly-optimistic growth rate estimates by analysts lacks merit, because adoption of the

Global Analyst Research Settlement[239] in 2003 helped to neutralize bias among financial analysts (Company Brief at 305, citing Exh. NG-RBH-Rebuttal-1, at 45). Additionally, the Company asserts that the Department has noted a lack of pronounced bias in EPS forecasts and states that the Attorney General has provided no direct evidence to demonstrate bias (Company Brief at 305-306). Ultimately, the Company argues, it is irrelevant whether the EPS forecasts are biased because they are relied upon by investors to set stock prices (Company Brief at 306).

In addition, the Company argues that the Attorney General's model is flawed, specifically, because of the reliance on forecasts of dividends-per-share and book-value-per-share (Company Brief at 304). The Company asserts that it performed a regression analysis that showed that while EPS had a statistically significant explanatory value on electric company stock price valuations, dividend-per-share, and book-value-per-share did not (Company Brief at 304). The Company also criticizes the Attorney General's use of historical data in determining the growth rate, which is a forward looking (Company Brief at 304).

The Company defends its use of a forecasted 5.45 percent GDP growth rate for the terminal growth rate in the multi-stage DCF model (Company Brief at 306). National Grid maintains that since 1990 the annual nominal growth rate in GDP has been relatively stable

[239] The Global Financial 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-RBH-Rebuttal at 45 n.100).

and above five percent for 13 of the 29 years (Company Brief at 306; Company Reply Brief at 107). The Company argues that its proposed growth rate is consistent with other respected forecasts of long-term GDP growth (Company Brief at 306-307, citing Exh. NG-RBH-Rebuttal-1, at 57). The Company argues that the GDP growth forecasts of the Congressional Budget Office of 4.0 percent and the U.S. Energy Information Administration of 4.3 percent do not cover the entire period of the Company's multi-stage DCF model (Company Brief at 307). The Company also contends that the Congressional Budget Office's own evaluation found that its GDP growth forecasts since the 1980s had real output growth and inflation forecasting errors of 1.30 percent and 0.9 percent, respectively (Company Brief at 307, citing Exh. NG-RBH-Rebuttal-1, at 58-59). National Grid asserts that the U.S. Energy Information Administration forecast is based on economic conditions at the time and, therefore, underestimates GDP growth if made during a recession (Company Brief at 307, citing Exh. NG-RBH-Rebuttal-1, at 59-60).

d. Analysis and Findings

In developing their proposed ROEs, both the Company and the Attorney General use a constant growth DCF model (Exhs. NG-RGH-1, at 4, 28-29). In the constant growth model, the cost of equity is the sum of the dividend yield and the growth rate (Exhs. NG-RBH-1, at 22-23; AG-JRW at 39-40). This model makes a number of strict assumptions, including that dividends, book value, and earnings all grow at the same constant rate in perpetuity, that the dividend payout ratio and cost of equity and price-to-earnings ratio remain constant, and that the cost of equity is greater than the expected rate of growth

(Exh. NG-RGH-1, at 23). These assumptions affect the estimates of the cost of equity. D.P.U. 15-155, at 364; D.P.U. 09-39, at 387. In addition, the Company has included a multi-stage DCF model that diminishes the assumption that the growth rate of dividends, book value, and earnings remains constant in perpetuity (Exh. NG-RBH-1, at 31-32).

The Company and Attorney General use different data sources to estimate the dividend yield and growth rates (Exhs. NG-RGH-1, at 24-25; AG-JRW at 42-43). The Company calculates a dividend yield in the range of 3.19 percent to 3.38 percent using annualized dividend and 30-day, 90-day, and 180-day average stock price data from Bloomberg, adjusting by one half of the growth rate based on data from Zacks, First Call, and Value Line (Exh. NG-RBH-Rebuttal-2). The Attorney General calculates a dividend yield in the range of 3.30 percent to 3.40 percent using data from Yahoo! Finance (Exh. AG-JRW-7, at 2). The Department finds that both the Company's and the Attorney General's approaches are logical and reasonable. Further, there is no evidence to establish that investors rely overwhelmingly on one data source over the other. Therefore, we find that both approaches provide a credible basis for evaluating a determination of the Company's allowed ROE.

The Company and the Attorney General use different growth rates in their respective DCF analyses; the Company uses averaged earnings growth data from Zacks, First Call, and Value Line, while the Attorney General uses a combination of EPS, dividends per share, and book value per share growth estimates derived from both Value Line and analyst projections (Exhs. NG-RBH-1, at 28; NG-RBH-3; AG-JRW at 7, 50-51; AG-JRW-7;

NG-RBH-Rebuttal-1, at 41; AG-JRW-Surrebuttal-1, at 15). Determining the appropriate long-term growth expectations of investors in a DCF analysis is often difficult and controversial. D.P.U. 15-155, at 365. The Company relies on the forecasted EPS growth rates of financial market analysts, based on the assumption that investors form their investment decisions based on expectations of growth in earnings and not dividends (Exhs. NG-RBH-1, at 25; NG-RBH-Rebuttal-1, at 46-47). On the other hand, the Attorney General bases her growth rate on a historical and forward-looking growth analysis using EPS, dividends-per-share, book-value-per-share, and retention growth rates (Exh. AG-JRW at 43). The Attorney General emphasizes dividend growth over earnings growth because of the alleged upward bias of forecasts by financial analysts (Exhs. AG-JRW at 46-47; AG-JRW-7, at 3, 4, 5, 6). In this case, however, there is evidence that EPS growth rates provide a more statistically reliable measure of growth than dividends-per-share or book-value-per share, in light of utility price-earnings ratios being greater than historical averages in recent years (Exhs. NG-RBH-Rebuttal-1, at 51; NG-RBH-Rebuttal-14). In view of this evidence, the Department places more weight on EPS growth rates.

Notwithstanding the weight we accord to EPS growth rates, however, the Department recognizes that investors acknowledge the existence of upward biases in EPS forecasts and take these biases into consideration in evaluating the results of a DCF analysis. D.P.U. 15-155, at 366; D.P.U. 13-75, at 302. Additionally, the Department recognizes that arithmetically, in the constant growth DCF model, an overstated EPS growth rate that is incorporated in the stock price puts downward pressure on the dividend yield. There is no evidence in the record to make a determination of the magnitude of directional forces on the cost of equity. Furthermore, the Department notes that the growth rate of the DCF model is that of dividends and that an underlying assumption of the DCF model is that dividends, earnings, and book value all grow at the same rate (Exhs. AG-JRW at 39; NG-RBH-1, at 25).

The Company argues that the Attorney General has provided no direct evidence that analysts' EPS forecasts are upwardly biased and that the Global Analyst Research Settlement has helped to neutralize the bias (Company Brief at 305; Company Reply Brief at 106). While the Global Analyst Research Settlement was intended to address conflicts of interest among analysts, there is no evidence that it addressed other causes of upward bias in EPS growth rates forecasts. These other causes are noted in a 2006 study by Easton and Sommers,[240] showing that a combination of factors can lead to overly-optimistic EPS forecasts by financial market analysts, resulting in an overstatement of the cost of equity by approximately three percentage points (Exh. NG-AG 2-7, Att., at 2, 6, 29). Although the Attorney General was not able to specifically connect this bias to electric utilities, we are persuaded that electric utilities are not somehow immune to forecast biases (Tr. 15, at 1748-1749). On this basis, the Department finds that analyst growth rate forecasts are still subject to overly-optimistic projections, thereby tending to overstate the required ROE.

---

[240] Easton, P., & Sommers, G. (2007). Effect of analysts' optimism on estimates of the expected rate of return implied by earnings forecasts. Journal of Accounting Research, 45(5), 983–1015 (Exh. NG-AG 2-7, Att.).

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. The constant growth model assumes that the earnings, dividends, and book value will grow at the same rate in perpetuity (Exh. NG-RBH-1, at 23). The Company has provided a multi-stage DCF model in its analysis, which allows the assumption to be diminished (Exh. NG-RBH-1, at 31-32). National Grid states that the model enables the analyst to incorporate assumptions regarding the timing and extent of changes in the dividend payout ratio[241] to reflect, for example, increases or decreases in expected capital spending, or transition from current payout levels to long-term expected levels (Exh. NG-RBH-1, at 33). The Company has not provided any evidence of expected changes in the level of capital spending or the dividend payout ratio justifying the use of the multi-stage DCF model. Further, the Company has incorporated a long-term nominal GDP growth rate of 5.45 percent, which the Department finds to be inappropriate as it puts too much emphasis on the GDP growth of the first half of the 20th century, ignoring the trend toward a GDP reflective of a mature economy. In addition, the electric distribution industry is a mature industry and should not be expected to experience the same growth rate as the economy as a whole. The Company argues that the GDP forecasts of the Congressional Budget Office and the U.S. Energy Information Administration are inappropriate because they do not cover the

241 The dividend payout ratio represents the percentage of a company's earnings that are paid out in dividend, versus retained by the company.

entire period as the Company's multi-stage DCF model (Company Brief at 307). The Congressional Budget Office forecast covers the period 2018 to 2048 and the U.S. Energy Information Administration forecast covers the period 2017 to 2050 (Exh. AG-JRW at 77-78). The Department finds these forecasts to be sufficiently long-term. While the Company argues that these forecasts are not consensus and not relied upon by investors, it has not provided any evidence that investors do not rely on them or that investors rely on the method that it used in estimating long-term GDP forecasts. Based on the foregoing, the Department recognizes the limitations of the Company's and Attorney General's DCF models, and will consider these limitations in determining appropriate cost of equity.

4. Capital Asset Pricing Models

a. Company CAPM Proposal

The Company used the CAPM to calculate the cost of equity for its proxy group (Exhs. NG-RBH-1, at 3, 6, 39: NG-RBH-6; NG-RBH-7). The application of the Company's CAPM resulted in eight individual costs of equity calculations, ranging from 8.18 percent to 11.29 percent (Exhs. NG-RBH-1, at 41, Table 7; NG-RBH-Rebuttal-1, at 105, Table 6; NG-RBH-7). National Grid considered these results when determining its proposed ROE (Exh. NG-RBH-1, at 4).

The CAPM is a market-based investment model based on capital markets theory and modern portfolio theory. D.P.U. 15-155, at 366. In the CAPM, the required ROE is equal to the expected risk-free rate of return plus a premium for the implicit systematic risk of the security (Exh. NG-RBH-1, at 37). The CAPM model includes three components in calculating the cost of equity: (1) an expected risk-free rate of return; (2) the market risk premium; and (3) the beta coefficient, a measure of systematic risk (Exhs. NG-RBH-1, at 37-38; NG-RBH-7).

The Company used the current 30-year U.S. Treasury bond yield of 3.03 percent and forecasted 30-year Treasury bond yields of 3.25 percent to determine the current and near-term risk-free rates (Exhs. NG-RBH-1, at 39; NG-RBH-Rebuttal-6). The Company then developed ex-ante or expected market risk premiums based on data from both Bloomberg and Value Line by calculating its respective estimated market-required returns less the U.S. Treasury bond yield (Exhs. NG-RBH-1, at 39-40; NG-RBH-7). The Company determined these market-required returns by applying its constant growth DCF model to the companies listed in S&P's 500 Index ("S&P 500"),[242] producing a market-required return of 13.64 percent based on data from Bloomberg, and a market-required return of 16.75 percent based on data from Value Line[243] (Exhs. NG-RBH-1, at 39-40; NG-RBH-5, at 1-14). Based on this analysis, the Company derived a market risk premium of 11.98 percent based on data

---

[242] The S&P 500 is an American stock market index based on the market capitalizations of 500 largest U.S. companies having common stock listed on the New York Stock Exchange or the NASDAQ Stock Market.

[243] The 13.64 percent expected market return is the sum of market capitalization-weighted dividend yields and market-weighted expected growth rates based on three- to five-year EPS growth rate estimates from Bloomberg (Exhs. NG-RBH-1, at 39-40; NG-RBH-Rebuttal-4, at 1-7). The 16.75 percent expected market return is the sum of market capitalization-weighted dividend yields and market capitalization-weighted expected growth rates based on three- to five-year EPS growth rate estimates from Value Line (Exhs. NG-RBH-1, at 39-40; NG-RBH-Rebuttal-4, at 8-14).

from Bloomberg, and a market risk premium of 13.32 percent based on data from Value Line (Exh. NG-RBH-7).

The Company obtained beta coefficients for its proxy group from Bloomberg (0.485) and Value Line (0.586) (Exhs. NG-RBH-1, at 40; NG-RBH-Rebuttal-6). The Company multiplied these beta coefficients by the Bloomberg and Value Line market risk premiums, then added the current and near-term risk-free rates to the results (Exh. NG-RBH-7). Based on this analysis, National Grid initially calculated (1) four CAPM results ranging from 8.18 percent to 9.47 percent using data from Bloomberg and (2) four CAPM results ranging from 9.69 percent to 11.29 percent using data from Value Line (Exhs. NG-RBH-Rebuttal-1, at 105, Table 7; NG-RBH-Rebuttal-6).

b. Company Empirical CAPM Proposal

During the proceedings, National Grid submitted an ECAPM analysis (Exh. NG-RBH-Rebuttal-1, at 75-81). The ECAPM 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-RBH-Rebuttal-1, at 76). According to the Company, 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-RBH-Rebuttal-1, at 76-81). 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-RBH-Rebuttal-1, at 76, Table 10). Conversely, a CAPM analysis for a company with a beta above 1.0 will overstate the required return, with the difference becoming greater as the beta increases (Exh. NG-RBH-Rebuttal-1, at 76, Table 10). The ECAPM mitigates this drift in beta coefficients through adjustments to the risk-free rate and the market risk premium components (Exh. NG-RBH-Rebuttal-1, at 76). Using the same data and approach as was used in its CAPM analysis, application of the Company's ECAPM resulted in eight individual cost of equity calculations, ranging from 9.54 percent to 12.71 percent (Exhs. NG-RBH-Rebuttal-1, at 105, Table 6; NG-RBH-Rebuttal-6).

c. Attorney General Proposal

The Attorney General used a traditional CAPM approach in which the cost of equity is equal to the sum of the interest rate on risk free bonds and an equity risk premium (Exhs. AG-JRW-1, at 52; AG-JRW-8). The equity risk premium is the product of the market risk and the mean beta coefficient for each proxy group (Exhs. AG-JRW-1, at 52; AG-JRW-8). The market risk premium is the expected return from the stock market minus the risk-free rate of interest (Exh. AG-JRW at 55). The beta coefficient is an estimated measure of the systematic risk of an individual stock (Exh. AG-JRW at 55). The Attorney General's CAPM analysis resulted in a cost of equity of 7.30 percent for her proxy group and 7.03 percent for the Company's proxy group (Exhs. AG-JRW at 63; AG-JRW-8).

In her analysis, the Attorney General used four percent as the risk-free rate, the upper bound yield on 30-year U.S. Treasury bonds for the period 2013-2019 (Exhs. AG-JRW at 53; AG-JRW-8). The beta coefficients she employed, of 0.60 for her proxy group and 0.55 for the Company's proxy group, are the mean unadjusted beta coefficients of the proxy group firms provided by Value Line (Exhs. AG-JRW at 54-55; AG-JRW-8, at 1, 3). She used a market risk premium of 5.5 percent for both proxy groups based on the midpoint a review of over 30 market risk premium studies, including surveys of companies, chief executive officers, financial forecasters, and financial analysts (Exhs. AG-JRW at 58-63; AG-JRW-8, at 5).

The Attorney General multiplied the estimated market risk premium of 5.5 percent by the beta coefficients of 0.60 and 0.55 to produce expected equity risk premiums of 3.300 percent and 3.025 percent for her proxy group and the Company's proxy group, respectively (see Exh. AG-JRW-8, at 1). The Attorney General then added the risk-free rate of four percent to her expected equity risk premiums to derive a cost of equity of 7.30 percent for her proxy group and 7.03 percent for the Company's proxy group (Exhs. AG-JRW at 63; AG-JRW-8, at 1).

d. Positions of the Parties

i. Attorney General

The Attorney General argues that the Company's CAPM analysis is inflated (Attorney General Brief at 89). She contends that the principle flaw in its analysis is the estimated market risk premiums (Attorney General Brief at 89). She asserts that there is no support found in historical stock and bond analyses, ex-ante studies, or the surveys of market analysts and financial professionals to support market risk premiums as high as those used in the Company's analysis (Attorney General Brief at 89). The Attorney General argues that the expected market returns of 15.08 percent and 16.42 percent estimated by the Company using the DCF model with S&P 500 data from Bloomberg and Value Line, respectively, are excessive and have no basis in reality[244] (Attorney General Brief at 89-90).

According to the Attorney General, the underlying flaw in the Company's analysis is the reliance on three- to five-year EPS growth rates to reflect long-term expectations of EPS growth (Attorney General Brief at 90). She argues 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 90, citing Exh. AG-JRW at 81-82). She maintains that long-term EPS and GDP growth are directly linked (Attorney General Brief at 90). The Attorney General asserts that the record demonstrates historic EPS and GDP growth rates at about one-half of the EPS growth rates employed in the Company's analysis (Attorney General Brief at 90). Furthermore, she argues, recent trends in GDP growth and projections of GDP growth indicate lower GDP and earnings growth in the future (Attorney General Brief at 90).

The Attorney General argues that her analysis demonstrates the absurdity of the Company's EPS growth rate, asserting that its reliance on three- to five-year EPS growth rates implies that the net income of the S&P 500 would reach 111.50 percent of the nominal GDP of the U.S. in 2050 (Attorney General Brief at 91-92, citing Exh. AG-JRW at 85-89). In addition, the Attorney General contends that the EPS growth is much more volatile than GDP growth resulting in short-term divergence between the two (Attorney General Brief

[244] The numbers referenced by the Attorney General on brief are from the Company's initial filing.

at 93). The Attorney General argues 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 93, citing Exh. AG-JRW-Surrebuttal at 8-9).

ii. Company

The Company argues that the Attorney General's CAPM calculation must be rejected because the equity risk premium she relied on assumes market returns that do not make theoretical or practical sense (Company Brief at 307, citing Exh. NG-RBH-Rebuttal-1, at 66). National Grid asserts that the market return estimated by the Attorney General is only twelve basis points greater than her recommended ROE, which is illogical given the relative risk (Company Brief at 307-308).

Additionally, the Company challenges the surveys relied upon by the Attorney General in calculating the equity risk premium in her CAPM analysis (Company Brief at 308). National Grid argues that some of the studies and surveys that the Attorney General's calculations relied on are of limited value, calling attention to surveys that the Attorney General claim significantly underestimated actual market performance (Company Brief at 308, citing Exh. NG-RBH-Rebuttal-1, at 61-64). Consequently, the Company argues, the Attorney General's analysis is based on certain surveys that should be given little or no weight (Company Brief at 308).

Finally, the Company dismisses the Attorney General's claim that reliance on analysts' forecasts invalidates the Company's CAPM approach (Company Brief at 308). The Company maintains that there is no recent evidence that supports her claim of upward bias in analysts' forecasts (Company Brief at 308, citing Exh. NG-RBH-Rebuttal-1, at 45). National Grid also asserts that for approximately 60 percent of the period 1926 to 2018, capital appreciation was greater than 13.07 percent (Company Brief at 308). National Grid argues that its market risk premiums is consistent with historical returns and analysts' forecasts of EPS growth and, therefore, the Department should give some weight to its analysis in setting the Company's ROE (Company Brief at 308-309).

e. Analysis and Findings

The Department has previously found that the traditional CAPM as a basis for determining a utility's cost of equity has limited value because of a number of questionable assumptions that underlie the model. D.P.U. 17-170, at 298; D.P.U. 15-155, at 370; D.P.U. 10-114, at 318; D.P.U. 10-70, at 270; D.P.U. 08-35, at 207; D.T.E. 03-40, at 359-360; Commonwealth Electric Company, D.P.U. 956, at 54 (1982). For example, the Department has not been persuaded that long-term government bonds are the appropriate proxy for the risk-free rate, and we have found that the coefficient of determination for beta is generally so low that the statistical reliability of the results is questionable. D.T.E. 01-56, at 113; D.P.U. 93-60, at 256-257; D.P.U. 92-78, at 113; D.P.U. 88-67 (Phase I) at 182-184.

The CAPM is based on investor expectations and, therefore, it is appropriate to consider a prospective measure for the risk-free rate component. D.P.U. 17-170, at 299; D.P.U. 15-155, at 371. Nonetheless, the Department notes that while the near-term projected yield of the 30-year U.S. Treasury bond was higher than the current yield in the

Company's filing, both the current yield and projected yields have consistently fallen since that time.[245] The Department also acknowledges the Attorney General's point that forecasts of an increasing risk free rate have been wrong for a decade (Exh. AG-JRW at 53-54).

Because the CAPM is considered an ex-ante, 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, the Department finds that the Company's approach based on DCF analyses is less reliable than the survey results of financial professionals (Exhs. AG-JRW at 60-63; NG-AG-2-10 (Atts.); Tr. 5, at 696-697) 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.

The Company developed a market risk premium imputing an expected market return by applying a DCF analysis to the analysts' earnings growth forecasts of Bloomberg and Value Line (Exhs. NG-RBH-1, at 39-40; NG-RBH-7). While the results may be indicative of investors' short-term expectations, the Department finds that they grossly overstate the long-term expectations of investors. In spite of the Company's assertion that capital appreciation in the United States was greater than 13.07 for 60 percent of the time during the period 1926 to 2018, there is no evidence in the record to suggest that the United States will experience a subsequent century of such prolific economic growth. To the contrary, GDP

245 The yield on 30-year U.S. Treasury bonds was 3.36 percent on the date of the Company's filing, November 15, 2018. At the time of the Company's rebuttal filing, April 22, 2019, the 30-year U.S. Treasury bond yield had declined to 2.99 percent. By the close of evidentiary hearings on May 24, 2019, it had fallen further to 2.75 percent. As of September 19, 2019, the yield had fallen to 2.22 percent. Federal Reserve Bank of St. Louis, https://fred.stlouisfed.org/series/DGS30

growth has been continually slowing during the past five decades (Exh. AG-JRW at 77). Therefore, the Department finds the Company's calculations of expected market returns, and consequently, its calculations of the market risk premiums are overstated. In estimating a market risk premium, the Attorney General has relied on over 30 surveys of and studies by financial professionals, academics, and market analysts from the last ten years (Exhs. AG-JRW at 80; AG-JRW-8). The Company has challenged the veracity of several of the surveys relied on by the Attorney General. These surveys appear to be based on limited sample data, and we thus place little weight on their results (Exh. NG-RBH-Rebuttal-1, at 61-63). Based on the above considerations, the Department will place limited weight on the results of the Company's and Attorney General's CAPM results in determining the allowed ROE.

5. Bond Yield Plus Risk Premium Model

a. Company Proposal

The risk premium method of 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-RBH-1, at 41). The general approach is relatively straightforward: (1) determine the historical spread between the return on debt and the ROE; and (2) add this spread to the current debt yield to derive a calculation of current equity return requirements. D.P.U. 13-75, at 316 n.201. In the risk premium model used by the Company, the cost of equity is derived by calculating a risk premium over the returns available to bondholders

(Exh. NG-RBH-1, at 41-42). The Company relied on data from 1,569 electric utility proceedings between January 1, 1980 and September 28, 2018 (Exhs. NG-RBH-1, at 42; NG-RBH-8). To account for the variability of bond interest rates and allowed ROEs, particularly during the 1980s and the post-Lehman bankruptcy period,[246] the Company used a semi-log regression[247] (Exhs. NG-RBH-1, at 43; NG-RBH-8).

The Company calculated the average 30-year U.S. Treasury yield over the average lag period between utility filings and public utility commission final order issuance, to reflect the prevailing interest rates during the proceedings (Exh. NG-RBH-1, at 42). The Company states that there is a statistically significant inverse relationship between interest rates and utility equity risk premiums (Exh. NG-RBH-1, at 42-43, citing Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry, Financial Management, Autumn 1995, at 89-95). The Company then applied its risk premium to three different thirty-year Treasury yields: (1) a current yield of 3.10 percent, (2) a near-term projected yield of 3.52 percent, and (3) a long-term projected yield of 4.30 percent (Exh. NG-RBH-1, at 41-44). Based on this analysis, the

---

246 The financial services firm Lehman Brothers Holdings, Inc. filed for bankruptcy on September 15, 2008, triggering a one-day drop in the Dow Jones Industrial Average of 4.5 percent and the 2008 financial crisis, which ushered in the Great Recession. https://www.nbcnews.com/business/economy/10-years-ago-lehman-brothers-went-bankrupt-triggered-recession-could-n909546 accessed September 23, 2019.

247 When data is non-linear a semi-log regression is often used transforming the dependent variable and allowing linear regression analysis. Because the log of negative numbers is undefined, the use of a semi-log regression can be inappropriate in some circumstances.

Company's equity risk premium model produces an ROE between 9.93 percent and 10.17 percent (Exhs. NG-RBH-Rebuttal-1, at 105, Table 6; NG-RBH-Rebuttal-7, at 1).

b. Positions of the Parties

i. Attorney General

The Attorney General asserts that the Company's application of the risk premium model is flawed in a number of ways, resulting in overstating the cost of equity (Attorney General Brief at 94). She argues that there are three primary errors with the derived risk premium (Attorney General Brief at 94). First, the Attorney General argues that the Company's method produces an inflated measure of the risk premium because it is based on historic allowed ROEs less historic U.S. Treasury yields, and then is applied to projected treasury yields that always are forecasted to increase (Attorney General Brief at 94-95). She argues that projected rather than historic U.S. Treasury yields would be the appropriate measure to use as they are always larger than current yields and would produce a lower risk premium (Attorney General Brief at 95).

Second, the Attorney General contends that the Company's overall approach improperly uses allowed ROEs as an input to the model and that such an approach is more of a gauge of public utility commission behavior than a consideration of investor behavior (Attorney General Brief at 95). In this regard, the Attorney General claims that in setting ROEs, regulatory commissions evaluate capital market data such as dividend yields, expected growth rates, interest rates, as well as rate case specific regulatory information (Attorney General Brief at 95). Further, the Attorney General argues that the Company's analysis overstates the risk premium because while National Grid relies on historical data to determine the spread between allowed ROEs and then-current 30-year U.S. Treasury rates, the Company applies this spread to forecasted Treasury rates (Attorney General Brief at 94-95, citing Exh. AG-JRW at 93-95). The Attorney General argues that a comparison of the Company's risk premium results to actual allowed ROEs for electric utility companies confirms the errors in the Company's approach (Attorney General Brief at 95, citing Exh. AG-JRW at 93-95).

Finally, the Attorney General argues that the Company's approach produces an inflated required rate because utility stocks have been selling at market-to-book ratios well in excess of 1.0 for many years (Attorney General Brief at 95). The Attorney General claims that the high ratio implies that authorized returns have exceeded the required return (Attorney General Brief at 95). In addition, the Attorney General asserts that the Company's long-term projected U.S. Treasury bond yield of 4.3 percent is unrealistic, arguing that investors would not buy U.S. Treasury bonds at their current yields of about 3.00 percent if they anticipated that they would suddenly increase to 4.30 percent (Attorney General Brief at 94, citing Exh. AG-JRW at 94).

ii. Company

National Grid defends its use of a prospective U.S. Treasury yield, arguing that setting an ROE for a utility is a forward-looking process (Company Brief at 309). Additionally, it notes that the Attorney General used a 4.0 percent risk-free rate in her

CAPM analysis, a mere 30 basis points less than the highest expected long-term risk-free rate used in the Company's analysis (Company Brief at 309).

The Company disputes the Attorney General's argument that the Company's risk premium approach is flawed because it gauges regulatory commission behavior rather than investor behavior (Company Brief at 309). National Grid argues that regulatory decisions reflect market-based analyses (Company Brief at 309, citing Exh. NG-RBH-Rebuttal-1, at 82). Further, the Company contends that because authorized returns are publicly available, such data are to some degree reflected in investors' return expectations and requirements (Company Brief at 309, citing Exh. NG-RBH-Rebuttal-1, at 82-83). For these reasons, the Company asserts that authorized returns are a reasonable measure of investor required returns (Company Brief at 309, citing Exh. NG-RBH-Rebuttal-1, at 82-83).

The Company maintains that the Department has viewed the risk premium approach as a "supplemental approach" in determining the level of ROE (Company Brief at 309, citing D.P.U. 07-71, at 137). Based on the above, National Grid argues that the Department should, at a minimum, supplement its calculation of the Company's ROE with the risk premium approach (Company Brief at 309).

c. Analysis and Findings

The Department has repeatedly found that a risk premium analysis can overstate the amount of company-specific risk and, therefore, the cost of equity. 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 ROE 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 several flaws inherent in the risk premium analysis presented by the Company. First, 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. 13-75, at 319; D.P.U. 90-121, at 171; D.P.U. 88-67 (Phase I) at 182-183. Moreover, the Company's approach presumes that allowed ROEs are determined on a purely quantitative basis. As we note below, management performance is a significant factor in the determination of an appropriate ROE; 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.

In addition, the Department has criticized the use of corporate bond yields in determining the base component of the risk premium analysis, and we are not convinced that the Company's substitution of projected U.S. Treasury debt yields provides a better approach. D.P.U. 17-170, at 303; D.P.U. 15-155, at 375; D.P.U. 09-39, at 388-389; D.P.U. 08-35, at 202-203; D.P.U. 90-121, at 171. The Company relies on the projected

U.S. Treasury rate in this model, arguing that setting an ROE for a company is forward looking and that, therefore, using the forward-looking approach is appropriate (Company Brief at 309). The Department disagrees. The risk premium model is based on current market conditions and is not a forward-looking approach. D.P.U. 13-75, at 319; D.P.U. 12-25, at 433. Accordingly, the Department finds that current U.S. Treasury yields are more appropriate than the forward-looking approach created by the use of projected yields in a risk premium analysis. For these reasons, the Department finds that National Grid's risk premium model overstates the required ROE for the Company and has limited value in setting the Company's ROE.

E. Conclusion

The standard for determining the allowed ROE is set forth in Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 692-693 (1923) ("Bluefield") and Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944) ("Hope"). The allowed ROE should preserve a company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of similar risk. Bluefield at 692-693; Hope at 603, 605. The allowed ROE should be determined "having regard to all relevant facts." Bluefield at 692.

The Company recommends that the Department approve an ROE of 10.50 percent (Exhs. NG-RBH-1, at 2-3; NG-RBH-Rebuttal-1, at 2). The Attorney General recommends an ROE of 8.75 percent along with an imputed capital structure or 8.60 percent using the

Company's proposed capital structure (Exh. AG-JRW at 5-6). The Department has found that both quantitative and qualitative factors must be taken into account in determining an allowed ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.P.U. 08-27, at 134-138; D.T.E. 02-24/25, at 229-231; D.P.U. 92-78, at 115; D.P.U. 89-114/90-331/91-80 (Phase I) at 224-225; see also 375 Mass. 1, 11; Boston Gas Company v. Department of Public Utilities, 359 Mass. 292, 305-306 (1971). Thus, in determining an appropriate ROE for National Grid, the Department first evaluates the quantitative factors presented in this case.

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). Conducting a model-based ROE analysis requires the analyst to make a number of subjective judgments. Even in studies that purport to be mathematically sound and highly objective, crucial subjective judgments are made along the way and necessarily influence the end result. Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977). Each level of judgment to be made in these models contains the possibility of inherent bias and other limitations. D.T.E. 01-56, at 117; D.P.U. 18731, at 59.

In support of its recommended ROE, National Grid has presented quantitative analyses using the DCF model, the CAPM, the ECAPM, and the risk premium approach, each incorporating the financial data of its proxy group (Exh. NG-RBH-1, at 3, 6, Table 1). The Attorney General has presented her analyses using the DCF model and the CAPM, incorporating the financial data of both her proxy group and the Company's proxy group

(Exhs. AG-JRW at 4; AG-JRW-9, at 2). The Company's DCF and CAPM cost of equity analyses assume that the U.S. Federal Reserve System would continue the process of monetary policy normalization resulting in increasing interest rates that would affect each of the models (Exh. NG-RBH-1, at 55-56). Subsequent to the Company's filing, there has been a reversal of U.S. Federal Reserve System policy and a consistent decline in the 30-year U.S. Treasury rate, thus reducing the Company's required ROE (Exh. AG-JRW at 10-15; Tr. 15, at 1752).

As discussed above, the evidence demonstrates that each cost of equity model used by the Company and the Attorney General suffers from a number of simplifying and restrictive assumptions. Applying these assumptions to the financial data of a proxy group could provide results that may not be reliable for the purpose of setting the Company's ROE. For example, we note the limitations of the DCF models used by both the Company and the Attorney General, including the simplifying assumptions that underlie the constant growth form of the model and its element of circularity. These shortcomings notwithstanding, the DCF model relies on classical valuation theory focusing on the intrinsic value of a company's stock as determined by the company's anticipated earning power and as such, is a powerful tool in developing the appropriate cost of equity and has consistently been relied on by public utility commissions in setting the allowed cost of equity in rate cases (Exh. NG-RBH-1, at 5, 8, 22).

The Department further finds that the CAPM analyses relied upon by the Company and the Attorney General also are flawed because of the simplifying assumptions underlying

CAPM theory and the subjectivity inevitable in estimating market risk premiums. To the extent we rely on the CAPM estimates, we give more weight to the Attorney General's analysis because the magnitude of the deficiencies within the Company's proposed CAPM, including the estimate of a market risk premium, is greater. Finally, we find that the Company's risk premium approach suffers from a number of limitations and tends to overstate National Grid's required ROE.

While the results of analytical models are useful, the Department must ultimately apply its own judgment to the evidence to determine an appropriate ROE. We must apply to the record evidence and argument considerable judgment and agency expertise 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 375 Mass. 1, 15.[248] The Department must account for additional factors specific to a company that may not be reflected in the results of the models.

We note that a portion of the revenues of the companies in both proxy groups is derived from unregulated and competitive lines of business (Exhs. NG-RBH-9; AG-JRW-2, at 1). All else equal, this mix of regulated and unregulated operations would tend to

---

[248] 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.

overstate the proxy groups' risk profiles relative to that of the Company. Therefore, in applying the comparability standard, we will consider such risk differentials when weighing the results of the models used to calculate the Company's allowed ROE. In addition, while the Department does not accept the Attorney General's recommendation to utilize the capital structure of the proxy groups, we recognize that the Company has a higher common equity ratio than that of its proxy groups and therefore, less financial risk, which we take into consideration when establishing the cost of equity.

In addition, the Company and the Attorney General debate the cause and effect connection between rate mechanisms and the cost of equity in the context of their respective proxy groups (Exhs. NG-RBH-1, at 47-48; NG-RBH-9; NG-RBH-Rebuttal-1, at 99-100; AG-JRW at 6, 95-98; AG-JRW-Surrebuttal-1, at 33-34). Although many companies in both proxy groups employ some form of revenue stabilization or revenue decoupling mechanism, the Department finds that the degree of revenue stabilization varies among the companies and precisely quantifying their relative effects on the required ROE in this proceeding is impractical (Exhs. NG-RBH-1, at 47-48; NG-RBH-9; AG-JRW at 6, 95-98; AG-JRW-2). Nonetheless, we take these uncertainties into consideration when determining an ROE.

In determining the allowed ROE, we have considered National Grid's specific rate mechanisms. In particular, the Department established in this Order a PBR mechanism that, among other things, allows the Company to implement an annual rate adjustment to provide revenue support for expenses and capital investment (see Section II.B.4., above). This more timely and flexible recovery serves to reduce a company's risks. Also, the Department approved a five-year stay-out provision as part of the Company's PBR, which could increase the Company's risks in meeting its financial requirements.

Further, we have considered National Grid's reconciling mechanisms. The Department previously approved a revenue decoupling mechanism for National Grid in D.P.U. 09-39, at 61-92, and has directed all gas and electric distribution companies to file for revenue decoupling in a base distribution rate proceeding. D.P.U. 07-50-A at 84. The Department has found that revenue decoupling mechanisms can act to reduce the variability of a company's revenues and, consequently, reduces its risks. D.P.U. 09-39, at 398; D.P.U. 09-30, at 371-372; D.P.U. 07-50-A at 72-73. In addition to the revenue decoupling mechanism, the Company presently has in place fully reconciling mechanisms to recover, outside of base distribution rates, a broad range of expense categories, including energy efficiency, EV, grid modernization, the CIRM, and pension/PBOP. As a result of this Order, the Company will retain the majority of these reconciling mechanisms. The Department concludes that the presence of these fully reconciling mechanisms covering a significant portion of the Company's expenses combined with the PBR Plan will result in lower risk for National Grid.

Finally, there are other qualitative factors that the Department will consider in determining a company's allowed ROE. It is both the Department's long-standing precedent[249] and accepted regulatory practice[250] to consider qualitative factors such as

---

[249] For example, the Department has set a utility's ROE at the low end of a range of reasonableness upon a showing that a utility's management performance was deficient. D.P.U. 17-170, at 312-313 (corporate irresponsibility warranted ROE at lower end of

management performance and customer service in setting a fair and reasonable ROE. With respect to a company's performance, the Department has determined that where a company's actions have had the potential to affect ratepayers or have actually done so, the Department may take such actions into consideration in setting the ROE. D.P.U. 11-01/D.P.U. 11-02, at 424; D.T.E. 02-24/25, at 231; D.P.U. 85-266-A/271-A at 6-14. Thus, the Department may set ROEs that are at the higher end or lower end of the reasonable range based on

---

reasonableness range); D.P.U. 12-86, at 275-276 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-43, at 220-222 (company's improper handling of billing error, failure to provide acceptable unaccounted for water report, improper flushing practices, and insufficient communication with customers warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424-427 (company shortcomings in storm response warranted ROE at lower end of reasonable range); D.P.U. 10-114, at 339-341 (company activities related to Department-ordered audit warranted ROE at lower end of reasonable range); D.P.U. 08-35, at 220 (customer service deficiencies warranted ROE at lower end of reasonable range); D.P.U. 08-27, at 136, 137 (failure to conduct competitive bidding for outside consultants and provide detailed rate case expense invoices warranted ROE at lower end of reasonable range); D.P.U. 85-266-A/271-A at 172-173 (failure to fulfil public service obligations warranted ROE at lower end of reasonable range).

[250] 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); 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); 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); 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).

above-average or subpar management performance and customer service. See, e.g., D.P.U. 09-39, at 399-400 (company's storm response and rapid restoration of service warranted ROE at the higher end of the reasonable range); D.P.U. 12-86, at 274-276 & n.181 (deficiencies regarding affiliate transactions and selection of rate case consultants warranted ROE at lower end of reasonable range); D.P.U. 11-01/D.P.U. 11-02, at 424, 427 (company shortcomings in storm response warranted ROE at lower end of reasonable range).

In establishing the Company's allowed ROE, the Attorney General recommends that the Department take into account what the Attorney General describes as the Company's "sustained lack of adequate planning in its IT investments since at least D.P.U. 10-55" (Attorney General Brief at 52). The Department also has concerns regarding the Company's management, for example, as it relates to the Phase I EV and Phase II EV Programs. Without additional information, however, we are not persuaded that a ROE adjustment on the basis of these management concerns is warranted at this time. Nonetheless, the Department has determined that it is appropriate to require a comprehensive management audit. As outlined in Section XV., below, such an audit will determine whether National Grid is conducting its business in an appropriate manner in terms of efficiency of operations and productivity of employees.

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 allowed ROE of 9.60 percent is within a reasonable range of rates that will preserve National Grid's financial integrity, will allow it to attract capital on reasonable terms and for the proper discharge of its public duties, will be comparable to earnings of companies of similar risk and, therefore, is appropriate in this case.[251] In making this finding, the Department has considered both qualitative and quantitative aspects of the parties' various methods for determining the Company's proposed ROE, as well as the arguments of and evidence presented by the parties in this proceeding.

XV. MANAGEMENT AUDIT

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's for over 40 years. Boston Edison Company, D.P.U. 19991, at 62-63 (1979); Boston Edison Company, D.P.U. 17795-A at 24 (1974). To address this concern, the Department has previously required management studies or audits.[252] 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

---

251 In setting this ROE, the Department has taken into consideration the amount of the storm fund assessment paid by the Company pursuant to G.L. c. 25, § 18. Fitchburg Gas and Electric Light Company et al. v. Department of Public Utilities, 467 Mass. 768 (2014).

252 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.

Department possesses broad investigative and supervisory authority over jurisdictional companies. 375 Mass. 1, 44.[253]

In the current proceeding, the Department has determined that there are certain areas that require further investigation into the efficiencies of operations and productivity of National Grid's management and personnel. For example, as discussed in further detail in Section VIII.F., above, both the Attorney General and the Department have concerns regarding whether the Company's IT strategy and cybersecurity plan focus appropriately on benefits to Massachusetts ratepayers. The Department finds some merit in the Attorney General's argument that the Company's approach to IT investment is reactive, uncoordinated, and has not been vetted to determine benefits Massachusetts ratepayers receive for the costs allocated to them (Attorney General Brief at 50).

The Department also has concerns regarding the Company's management of its Phase I EV and Phase II EV Programs. The Company stated that it anticipates that the same individuals will work on both phases (Exh. DPU-NG 31-1). Nonetheless, the emerging products team provided supporting testimony in the instant proceeding, while the new energy solutions group provided supporting testimony in D.P.U. 17-13 (Exh. NG-RS-1, at 1).

---

253 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." 375 Mass. 1, 44.

D.P.U. 17-13, at 3.[254] It thus appears that two different groups were involved in the development of the two phases of the EV Program. In addition, National Grid proposes to hire new staff for the Phase II EV Program, but it is unclear from the record evidence whether this expansion is based on the existing staffing and program management structure of the Phase I EV Program (Exhs. NG-RS-1, at 49; NG-RS-4, at 1). The Department expects a certain level of continuity in utility management and staffing, and particularly in programs like EV that tend to have a steep learning curve where effective program performance can benefit from gained experience. Continuity of staffing will enable multi-year planning and financial discipline. Staff's ownership and commitment to their job duties will be essential to achieve efficiencies under the PBR Plan, while constant reorganizations have the potential to systematically disenfranchise and deskill the workforce.

Finally, the Department has concerns about the Company's management of its interconnection process in light of the ongoing transmission study being performed in central and western Massachusetts ("Cluster Study"). The Company states that the Cluster Study (1) is a transmission study performed by New England Power Company[255] and (2) is not

[254] Because of the Department's concerns regarding the management structure, we attempted to obtain comprehensive documentation explaining National Grid's management structure (Tr. 5, at 634-636; Tr. 14, at 1695-1696). The management structure provided by the Company, however, does not include the emerging products team or the new energy solutions group so it is impossible to ascertain their relationship, if any (RR-DPU-10; RR-DPU-32 (Supp.), Att.).

[255] New England Power Company and the Company are separate operating companies of National Grid USA (RR-DPU-10). Based on evidence and testimony provided by the Company, it is not clear whether and how the functions of the two companies are separated (Tr. 5, at 634-636; RR-DPU-10, Att.; RR-DPU-32 (Supp.), Att.)

subject to the requirements of the Company's Standards for Interconnection of Distributed Generation tariff, M.D.P.U. No. 1320 (Exh. NECEC 3-2, at 1). Nonetheless, the Cluster Study was a direct result of impacts identified in distribution system studies (RR-DPU-11, at 5-6; Tr. 5, at 618-621). As such, National Grid was aware of the magnitude and scope of these issues well before the Cluster Study began.[256] We are troubled that the Company did not inform the Department of the potential for a Cluster Study in a timely manner given the likeliness of the Cluster Study to delay the interconnection of affected projects, which total over 900 MW (see e.g., Tr. 5, at 602), or more than half of the Commonwealth's target for solar development under the solar Massachusetts renewable target ("SMART") program.[257] Based on the record evidence, the delay could be years depending on the length of the study and the time needed to implement any necessary system upgrades.[258] The Company's failure to meaningfully engage with the Department and stakeholders prior to the commencement of the Cluster Study raises serious concerns about management decisions made at the Company,

---

256 The Company states it became aware of the potential for large-scale distribution and transmission system upgrades in early 2018, and identified substation modifications and substation locations by September 2018 (RR-DPU-11, at 5-6). The Cluster Study commenced in March 2019 (RR-DPU-11, at 7).

257 In compliance with An Act Relative to Solar Energy, St. 2016, c. 75, § 11(b), DOER implemented a statewide solar incentive program, the SMART program. The SMART Program, which is administered by DOER, is a 1,600-MW declining block incentive program that is designed to promote solar development in the Commonwealth. 225 CMR 20.00.

258 Once the study begins, New England Power Company anticipates that it could take anywhere from twelve to 24 months to complete (RR-DPU-11, at 7). New England Power Company and National Grid indicate that necessary system upgrades could take anywhere from two to five years to complete (RR-DPU-11, at 8).

whether these decisions serve the public interest, and about the efficiency and timeliness of communications between personnel performing the work and management.

Based on the foregoing, the Department finds that the Company and its ratepayers would benefit from a more in-depth review of National Grid's management practices through a comprehensive independent management audit of the Company. Pursuant to the Department's supervisory authority over National Grid, we will 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. Evaluation of the strategic plan of the organization of National Grid and the interaction with NGSC can identify how work processes flow and whether there is appropriate integration and alignment between business groups. Regarding staffing decisions, the Department has concerns over disruptions caused by continuing reorganization that could undermine the efficiency gains inherent in PBR. Specifically, the audit shall review any staffing disruptions that either have diminished the foundations of expertise and knowledge of employees or staffing disruptions that may increase the cost of service through continual hiring, training, and retraining. Finally, regarding potential management problems, the Department seeks to identify and assess the relationship between National Grid and NGSC decisions on staffing organizations, staffing levels, and assignment of work functions and responsibilities. This matter will be docketed as D.P.U. 19-117. The final scope of and procedures for the audit will be determined by the Department after comment from interested stakeholders. The costs of the audit shall be borne by National Grid shareholders.

XVI. 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. D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401; D.T.E. 03-40, at 365; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 134.

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. 13-75, at 330; D.P.U. 12-25, at 445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 401; D.T.E. 03-40, at 365-366; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 134-135.

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. Fairness means that no class of consumers should pay more than the costs of serving that class. Earnings stability means that the amount a company earns from its rates should not vary significantly over a period of one or two years. D.P.U. 13-75, at 331; D.P.U. 12-25, at 444-445; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402; D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 252-253; D.T.E. 01-56, at 135.

There are two steps in determining rate structure: cost allocation and rate design. Cost allocation assigns a portion of a company's total costs to each rate class through an embedded ACOSS. The allocated cost of service represents the cost of serving each rate class at equalized rates of return given the company's level of total costs. D.P.U. 13-75, at 331; D.P.U. 12-25, at 445-446; D.P.U. 10-114, at 342; D.P.U. 09-39, at 402-403; D.T.E. 03-40, at 366; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 135.

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.[259] The second step is to classify expenses in each functional category according to the factors underlying their causation. Thus, the expenses are classified as

---

[259] Because the Company no longer owns generation assets, unbundled its services, and is proposing distribution service rates, it provided an ACOSS that included only distribution service costs and as such functionalized its costs into distribution service functions such as primary distribution, secondary distribution, and billing.

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 on the cost groupings and allocators chosen and then to sum for each rate class the costs allocated in order to determine the total costs of serving each rate class at equalized rates of return. D.P.U. 13-75, at 331-332; D.P.U. 12-25, at 446-447; D.P.U. 09-39, at 402-403; D.T.E. 03-40, at 366-367; D.T.E. 02-24/25, at 253; D.T.E. 01-56, at 135-136; D.T.E. 98-51, at 131-132; D.P.U. 96-50 (Phase I) at 133-134.

The results of the ACOSS are compared to the revenues collected from 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 equalize the rate of the return and ensure that each rate class pays the cost of serving it. If, however, the differences between the allocated costs and the test-year revenues are significant, then, for reasons of continuity, the revenue increase or decrease may be allocated so as to reduce the difference in rates of return, but not to equalize the rates of return in a single step. D.P.U. 13-75, at 332; D.P.U. 12-25, at 446; D.P.U. 09-39, at 403; D.T.E. 03-40, at 367; D.T.E. 02-24/25, at 253-254; D.T.E. 01-56, at 136.

As the previous discussion indicates, the Department does not determine rates based solely on the results of an ACOSS, but we also explicitly consider the effect of our rate structure decisions on the amount 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 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. D.P.U. 13-75, at 332; D.P.U. 12-25, at 447; D.P.U. 09-39, at 403-404; D.T.E. 03-40, at 367; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 136. To reach fair decisions that encourage efficient utility and consumer actions, the Department's rate structure goals must balance the often divergent interests of various customer classes and prevent any class from subsidizing another class unless a clear record exists to support such subsidies – or unless such subsidies are required by statute, e.g., G.L. c. 164, § 1F(4)(i) (discounted low-income rates). In addition, G.L. c. 164, § 94I, 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.[260] The Department reaffirms our rate structure goals, which are designed to result in rates that are fair and cost-based and enable customers to adjust to changes. D.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 137.

---

[260] General Laws c. 164, § 94I, provides:

> In each base distribution rate proceeding conducted by the department under Section 94, the department shall design base distribution rates using a cost-allocation method that is based on equalized rates of return for each customer class; provided, however, that if the resulting impact of employing this cost-allocation method for any 1 customer class would be more than 10 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.

The second step in determining the rate structure is rate design. The level of the revenues to be generated by a given rate structure is governed by the cost allocated to each rate class in the cost allocation process. The pattern of prices in the rate structure, which produces the given level of revenues, is a function of the rate design. The overarching requirement for rate design is 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. 15-155, at 386; D.P.U. 15-80/D.P.U. 15-81, at 298; D.P.U. 13-75, at 333; D.P.U. 12-25, at 447; D.P.U. 09-39, at 404; D.T.E. 02-24/25, at 254; D.T.E. 01-56, at 137. Further, G.L. c. 164, § 141, provides:

> In all decisions or actions regarding rate designs, the department shall consider the impacts of such actions, including the impact of new financial incentives on the successful development of energy efficiency and on-site generation. Where the scale of on-site generation would have an impact on affordability for low-income customers, a fully compensating adjustment shall be made to the low-income rate discount.

B. Allocated Cost of Service Study

1. Company Proposal

National Grid performed an ACOSS that directly assigns or allocates, based on cost-causation principles, each element of the revenue requirement among the rate classes (Exh. NG-HSG-1, at 3-4). There are three steps to the Company's ACOSS. First, the Company functionalizes costs by its basic function, such as primary distribution, secondary distribution, and billing (Exh. NG-HSG-1, at 4).[261] The primary distribution function includes costs related to substations, conductors rated four kilovolt ("kV") and higher, transmission, and production assets (Exh. NG-HSG-1, at 6). The secondary distribution function includes costs related to conductors and other assets that move electricity from the primary system to customers' premises (Exh. NG-HSG-1, at 6). The billing function includes costs related to measuring, billing, and collecting for services the Company provides, including customer support (Exh. NG-HSG-1, at 6).

Second, the Company classifies each functionalized cost as either demand-, energy-, or customer-related according to the system design or operation characteristics that cause them to be incurred (Exh. NG-HSG-1, at 15). Demand-related costs are associated with plant that is designed, constructed, and operated to meet system peak demand or non-coincident class peak demand (Exh. NG-HSG-1, at 14). Energy-related costs vary with the electricity delivered to customers (Exh. NG-HSG-1, at 14). Customer-related costs are incurred to attach a customer to the distribution system, to meter and read usage, and to maintain the meter, service drop, and the customer's account (Exh. NG-HSG-1, at 13-14). Customer-related costs are a function of the number of customers National Grid serves, are incurred whether or not a particular customer uses any electricity, and typically do not vary with usage or load profile (Exh. NG-HSG-1, at 13-14).

---

[261] There are separate functions for primary distribution and secondary distribution because some customers take service at primary voltages (Exh. NG-HSG-1, at 6).

Third, the Company allocates each functionalized and classified cost element to each rate class based on cost-causation principles (Exh. NG-HSG-1, at 15).[262] Costs are either directly assigned or allocated to rate classes (Exh. NG-HSG-1, at 15).

In allocating costs to rate classes, the Company used external and internal allocators (Exh. NG-HSG-1, at 11). External allocators are developed in special studies derived from the Company's accounting, operating, and other records (Exh. NG-HSG-1, at 11). Examples of external allocators are (1) the numbers of customers in each rate class, (2) class non-coincident peak demands, and (3) historical bad debt experience for each rate class (Exh. NG-HSG-1, at 11). Internal allocators are developed within the ACOSS using a combination of external allocators and other internal allocators (Exh. NG-HSG-1, at 11). The Company explains that the internal allocator for property insurance costs, for example, is based on plant investment and, therefore, plant investment must be allocated to each rate class before property insurance costs can be assigned to each rate class (Exh. NG-HSG-1, at 11).

National Grid set its initial revenue requirement target for each rate class to generate equalized rates of return (Exh. NG-HSG-1, at 20). This step resulted in an overall average percentage increase to existing base distribution rates of 18.06 percent (Exh. NG-HSG-1, at 22). Consistent with G.L. c. 164, § 94I and applicable Department requirements, the Company modified the results of the revenue allocation computed in the ACOSS so that no

---

262 Inherent in this third step is the process of identifying an allocator that is most appropriate for costs in each classification within each function.

rate class received a proposed increase in distribution revenue that is greater than ten percent of total normalized revenue from all rates and charges, including imputed commodity revenue for customers with competitive suppliers, for that rate class (Exh. NG-HSG-1, at 21). Based on the results of its ACOSS, the street lighting class required an increase greater than ten percent to reflect the full cost of service indicated in the ACOSS (Exh. NG-HSG-1, at 21). Therefore, the Company proposed to limit the increase for this class and reallocated the shortfall to the non-capped classes in proportion to their distribution revenue requirement at equalized rates of return (Exh. NG-HSG-1, at 21). Moreover, National Grid proposed to limit the distribution revenue increase for Rate R-4 to 36.12 percent (i.e., 200 percent of the overall distribution revenue increase) (Exh. NG-HSG-1, at 22).[263] The Company proposed to allocate the revenue shortfall to all other rate classes based on each rate class's share of base distribution revenue at equalized rates of return (Exh. NG-HSG-1, at 22).

2. Positions of the Parties

On brief, the Company outlined the Department's standard for conducting an ACOSS (Company Brief at 460-461). The Company states that it based its rate proposals on its ACOSS (Company Brief at 461). The Attorney General does not object to the Company's proposed ACOSS or the Company's method to determine the allocation of any revenue increase among the customer classes (Attorney General Brief at 111). No other party commented on this issue on brief.

---

263 Rate R-4 is a residential time-of-use rate class and is optional for customers whose use exceeds 2,500 kWh per month for a twelve-month period (Exhs. NG-HSG-1, at 26; DPU-NG 21-7).

3. Analysis and Findings

The Department has reviewed the Company's proposed ACOSS and finds it to be acceptable. Accordingly, the Department approves the Company's ACOSS.

C. Marginal Cost Study

1. Introduction

The use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 15-155, at 395; D.P.U. 15-80/D.P.U. 15-81, at 310; D.P.U. 14-150, at 374; D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524. Rates based on a marginal cost study allow consumers to make informed decisions regarding their use of utility services, promoting efficient allocation of societal resources. D.P.U. 15-155, at 395; D.P.U. 15-80/D.P.U. 15-81, at 310; D.P.U. 14-150, at 374; D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524.

2. Company Proposal

National Grid's marginal cost study follows the same methodology that was used in its last base distribution rate case, D.P.U. 15-155,[264] with several modifications

---

[264] The Company notes that similar to the marginal cost study filed in D.P.U. 15-155, the instant study contains data applicable only to MECo and no data for Nantucket Electric (Exh. NG-MCS-1, at 4). National Grid states that Nantucket Electric's total plant in service is less than two percent of the Company's total; therefore, omitting Nantucket Electric had no material effect on the marginal cost study (Exh. NG-MCS-1, at 4).

(Exh. NG-MCS-1, at 4).[265] To develop the marginal cost study, National Grid first identified the components of distribution plant that are demand related (Exhs. NG-MCS-1, at 7; NG-MCS-2).[266] The Company then adjusted these historical costs to 2017 values using the Handy-Whitman Index (Exhs. NG-MCS-1, at 7; NG-MCS-2). Following this adjustment, using account-specific percentages, National Grid calculated the separate plant addition costs attributable to primary versus secondary distribution systems (Exhs. NG-MCS-1, at 7; NG-MCS-2). Finally, as the marginal cost study is only concerned with plant additions that are made to support load growth, the percentage of distribution plant additions made to meet

---

265 First, the Company's marginal cost study filed in D.P.U. 15-155 initially excluded Structures and Improvements, Poles and Fixtures and Underground Conduits because those assets have no load carrying capacity (Exh. NG-MCS-1, at 8). These items subsequently were included in the D.P.U. 15-155 study, and were included initially in the instant study (Exh. NG-MCS-1, at 8). Second, National Grid determined that load relief is considered to be incurred for level of service and not for load growth, and, therefore, it was excluded from the instant study (Exh. NG-MCS-1, at 8-9). Third, National Grid determined that a portion of transformer capital spending is growth-related, and, therefore, it should be included in the Company's current marginal cost study (Exh. NG-MCS-1, at 9). Finally, in computing the growth-related portion of capital spending, the denominator was changed to include all capital spending, to align with the capital spending dollars reflected in the Plant Distribution $ for Growth, Secondary Distribution $ for Growth amounts (Exh. NG-MCS-1, at 9).

266 The following variables were determined to be exclusively demand-related: (1) Structures and Improvements; (2) Station Equipment; (3) Poles and Fixtures; (4) Overhead Conductors; (5) Underground Conductors; and (6) Line Transformers (Exhs. NG-MCS-1, at 7; NG-MCS-2).

growth was determined and the primary and secondary distribution plant costs made for replacement were removed (Exhs. NG-MCS-1, at 7-8; NG-MCS-2; NG-MCS-4).[267]

Next, by regressing three dependent variables, Plant Distribution $ for Growth, Secondary Distribution $ for Growth, and Distribution Demand $ for O&M on various independent variables,[268] the Company concluded that the independent variable Forecast 95/05 Peak Linear[269] had the best fit and was transformed to system peak demand (Exhs. NG-MCS-1, at 11-12; NG-MCS-6; NG-MCS-7). These costs were adjusted from 2017 dollars to 2020 dollars and adjusted for loss factors (Exhs. NG-MCS-1, at 15, 17; NG-MCS-6; NG-MCS-7; NG-MCS-10).

---

267 The percentage of distribution plant additions made to meet growth for the years 1984-2014 was obtained from the marginal cost study prepared in D.P.U. 15-155 and using the Company's 2016 Capital Investment Report, for the years 2015-2017 (Exh. NG-MCS-1, at 7-8).

268 The two dependent variables, Plant Distribution $ for Growth and Secondary Distribution $ for Growth, were derived by multiplying the annual percentages for growth by total capital additions for primary and secondary distribution (Exhs. NG-MCS-1, at 8; NG-MCS-2). The third dependent variable, Distribution Demand $ for O&M, was obtained from MECo's FERC Form 1 and indexed to 2017 dollars using the regional urban Consumer Price Index (Exhs. NG-MCS-1, at 9; NG-MCS-3).

269 Forecast 95/05 Peak Linear was derived using the actual forecast peaks from 2004 at the 95-percent level (i.e., there is a 95 percent chance that the peak would not exceed this level) and by using a three-year forward average of actual peaks for the years prior to 2004 (Exhs. NG-MCS-1, at 11-12; NG-MCS-7).

The results from the regression analysis calculated the marginal cost per kW of demand in 2020 dollars[270] at $112.73 for primary voltage and $46.39 for secondary voltage (Exhs. NG-MCS-1, at 17; NG-MCS-10). After adjusting for losses, the final results of the regression analysis calculated the marginal primary distribution costs at $115.15 per kW and marginal secondary distribution costs at $167.43 per kW (Exhs. NG-MCS-1, at 18; NG-MCS-11). Finally, the Company calculated the marginal cost for each rate class by multiplying the marginal cost per kW by the demand in the test year for each rate class, and then grossed up these amounts by class-specific uncollectable costs for each rate class (Exhs. NG-MCS-1, at 18; NG-MCS-12; NG-MCS-13).

3. Positions of the Parties

On brief, National Grid provides a summary of its marginal cost study and argues that the method used is consistent with that approved by the Department in the Company's prior two base distribution rate cases (Company Brief at 464, citing D.P.U. 15-155, at 398-399; D.P.U. 09-39, at 415-416). No other party addressed the Company's marginal cost study on brief.

4. Analysis and Findings

The Department has evaluated National Grid's proposed marginal cost study and finds that it incorporates sufficient detail to fully understand the methods used to determine the marginal cost estimates. As an initial matter, the Company excluded from the marginal cost

---

270 To adjust the costs to 2020 dollars, the Company applied the compound annual average increase in construction costs (Exhs. NG-MCS-1, at 17; NG-MCS-2).

study all production, transmission, and customer costs,[271] as they are irrelevant to the design of distribution rates under the Department's current rate design (Exh. NG-MCS, at 2). This methodology is consistent with Department precedent. D.T.E. 05-27, at 322 & n.170; D.T.E. 03-40, at 377. Further, we conclude that the Company followed the methodological guidelines set forth by the Department in developing its marginal cost study (Exhs. NG-MCS-1, at 6-14; NG-MCS-6; NG-MCS-7; NG-MCS-8).[272]

No intervening party addressed the Company's marginal cost study on brief, but in prefiled testimony the Attorney General's rate design witness raised several concerns about the results of the study.[273] While we acknowledge these concerns, we conclude that in light of our findings below, we need not reach the merits of the Attorney General's arguments.

---

271 Customer costs are costs associated with expanding the Company's customer base.

272 These guidelines include: (1) the use of historical data sets of no less than 30 years; (2) tests and remedial procedures for issues such as multicollinearity, heteroscedasticity, and autocorrelation; (3) multiple variable regression analysis; (4) consistency check against economic theory concerning marginal cost modeling; and (5) minimal dummy variable and autoregressive term use. See D.T.E. 05-27, at 317-322; D.T.E. 02-24/25, at 243-245.

273 Specifically, the Attorney General claimed that the results of the Company's marginal cost study are inconsistent with the study performed in D.P.U. 15-155, in particular, because the marginal cost of serving the residential rate class's demand increased by more than 50 percent but the class's total cost of service increased by less than eight percent (Exhs. AG-SJR-1, at 5-6). Further, the Attorney General argued that the Company's marginal cost study conflicts with economic theory, which provides that a natural monopoly (i.e., the Company's electric distribution operations) will have a marginal cost that is less than average cost (Exh. AG-SJR-1, at 6-7). Finally, the Attorney General questioned the relevance of the marginal cost study to the ratemaking process, particularly in designing rates, and she noted that the rate design methodology typically used by the Department does not rely directly on the results of the marginal cost study (Exh. AG-SJR-1, at 8).

The Department has long required electric and gas distribution companies to provide a marginal cost study as part of a base rate case filing. As noted above, the use of a marginal cost study facilitates the development of rates that provide consumers with price signals that accurately represent the costs associated with consumption decisions. D.P.U. 15-155, at 395; D.P.U. 15-80/D.P.U. 15-81, at 310; D.P.U. 14-150, at 374; D.P.U. 11-01/D.P.U. 11-02, at 438; D.P.U. 10-55, at 524. However, as a practical matter, the Department does not rely on a marginal cost study in designing rates for electric and gas distribution companies. Rather, in evaluating a petitioning company's rate design proposals, the Department considers its rate design goals: to achieve efficiency and simplicity, as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. See, e.g., D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401. We also consider relevant statutory requirements in determining appropriate rate design and allocation. E.g., G.L. c. 164, § 94I (cost-allocation method based on equalized rates of return for each customer class with specific parameters). Apart from rate design considerations, the Department uses the results of a marginal cost study to evaluate the cost effectiveness of special contracts (i.e., whether service under a special contract is priced above a company's marginal distribution costs); such contracts are almost exclusively with local gas distribution companies. See, e.g., D.T.E. 03-40, at 377.

In the instant proceeding, and consistent with past practice, the Department did not rely on National Grid's marginal cost study in designing the Company's rates (see

Section XVI.B. above, and Section XVI.F., below). Further, we conclude that we would reach the same decisions regarding the Company's approved rate design and allocation even in the absence of a marginal cost study. We also note that the Company does not use the marginal cost study for any purpose outside of the current base distribution rate case (Exh. DPU-NG 23-8).

Based on all of the foregoing considerations, the Department neither accepts nor rejects the Company's marginal cost study, as the study has no relationship to the rates established in this Order, nor is it used for any other purpose related to this base distribution rate case. Further, based on the above, we find no compelling reason to continue to require National Grid to file a marginal cost study as part of future electric base distribution rate cases.[274] In the event that National Grid needs to determine marginal cost in the future for either MECo or Nantucket Electric, the Company shall follow the Department's accepted methodology and guidelines in preparing an appropriate marginal cost study. See, e.g., D.T.E. 05-27, at 317-322; D.T.E. 03-40, at 377; D.T.E. 02-24/25, at 243-245.

---

[274] To the extent that the electric operations of NSTAR Electric or Unitil do not rely on a marginal cost study outside of a base rate case, that company shall attest to the same as part of its respective next electric base distribution rate case filing, and it need not submit a marginal cost study as part of that filing. Unless and until otherwise directed by the Department, all local gas distribution companies shall continue to provide a marginal cost study as part of their respective base distribution rate case filings.

D. Low-Income Discount

1. Introduction

Pursuant to G.L. c. 164, § 1F, the Department requires distribution companies to provide discounted rates for low-income customers comparable to the low-income discount rate received off the total bills for rates in effect prior to March 1, 1998. Expanding Low-Income Customer Protections and Assistance, D.P.U. 08-4, at 36 (2008). In the Company's last base distribution rate proceeding, the Department found it appropriate to increase the low-income discount rate from 25 percent to 29 percent, pursuant to G.L. c. 164, § 141 (Exh. NG-HSG-1, at 34). D.P.U. 15-155, at 470-471; Compliance Filing, Exh. NG-PP-14(C) (First Amended), at 4. Using that same method employed to account for increased costs associated with the renewable portfolio standard solar carve out and the net metering recovery surcharge, the Company proposed an increase in the low-income discount percentage to 32 percent (Exh. NG-HSG-1, at 34). The Attorney General endorsed the Company's calculation of the low-income discount and no party discussed the issue on brief (Exh. AG-SJR-1, at 11).

2. Analysis and Findings

Pursuant to G.L. c. 164, § 141, a fully compensating adjustment shall be made to the low-income discount where the scale of on-site generation would have an impact on affordability for low-income customers. D.P.U. 15-155, at 469. In D.P.U. 15-155, at 470-471, the Department determined that a fully compensating adjustment to the low-income discount would include only the costs associated with the renewable portfolio standard solar carve out and the net metering recovery surcharge, as these costs are directly related to the growth of on-site generation, and directed all electric distribution companies to file rate design proposals that comply with the standard set forth in G.L. c. 164, § 141.

Based on our review of the record, the Department finds that on-site generation in the Company's service territory has grown with an increase in costs from associated incentives that the Company includes in customers' bills, including bills of low-income customers (Exhs. NG-HSG-1, at 34; NG-HSG-7, at 2). Thus, low-income customers have experienced an increase in bills as a result of the growth of on-site generation. Therefore, pursuant to G.L. c. 164, § 141, and the Department's directive in D.P.U. 15-155, the Department finds that the Company's revised proposal to adjust the low-income discount is appropriate. The adjusted low-income discount of 32 percent will remain in effect until the Company's next base distribution rate case, at which time the Department will determine whether further adjustment is warranted.

E. Monthly Minimum Reliability Contribution

1. Introduction

Pursuant to G.L. c. 164, § 139(j) ("Section 139(j)"), the Department has the authority to consider proposals for an MMRC.[275] The purpose of the MMRC is for all distribution

[275] On April 11, 2016, Governor Baker signed into law Chapter 75 of the Acts of 2016, An Act Relative to Solar Energy. Among other things, the legislation added Section 139(j). St. 2016, c. 75, § 9. Subsequently, on August 9, 2018, Governor Baker signed into law An Act to Advance Clean Energy, which amended the statutory requirements in Section 139(j) for the Department to consider in reviewing a proposed MMRC. The legislation became effective on November 9, 2018. St. 2018, c. 227, §§ 15, 16, 17, 24.

company customers to contribute to the fixed costs that ensure the reliability, proper maintenance, and safety of the electric distribution system. Section 139(j). A distribution company may assess an MMRC designed as a demand charge if it is based on system peak demand during the hours of a day determined to be peak hours of system demand and if the distribution company regularly informs affected customers of the manner in which demand charges are assessed and of ways in which said customers might manage and reduce demand. Section 139(j). MMRC proposals shall be filed with the Department in (1) a distribution company's base distribution rate proceeding or (2) a revenue neutral rate design filing that is supported by appropriate cost of service data across all rate classes. Section 139(j).

The Department may approve an MMRC that: (1) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (2) does not excessively burden ratepayers; (3) does not unreasonably inhibit the development of Class I, Class II, and Class III net metering facilities; and (4) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system. Section 139(j). Further, the Department "may only approve a proposal for a monthly minimum reliability contribution after the aggregate nameplate capacity of installed solar generating facilities in the [C]ommonwealth is equal to or greater than 1,600 megawatts." Section 139(j). On September 8, 2017, the Department certified that such threshold had been reached. Net Metering Rulemaking, D.P.U. 16-64-G at 20 (2017). Moreover, pursuant to the statute, the Department shall determine the date upon which an approved MMRC shall take effect. Section 139(j).

In addition, consistent with established regulatory requirements, an MMRC must be just and reasonable. 438 Mass. 256, 264 n.13; Attorney General v. Department of Public Utilities, 392 Mass. 262, 265 (1984); 371 Mass. 881, 882; D.P.U. 10-114, at 22; D.P.U. 93-60, at 212. A utility's rates are just and reasonable when its rates afford it the opportunity to meet its cost of service, including a fair and reasonable return on honestly and prudently invested capital. 367 Mass. 92, 97; Lowell Gas Co. v. Department of Public Utilities, 324 Mass. 80, 94, cert. denied, 338 U.S. 825 (1949); Donham v. Public Service Commissioners, 232 Mass. 309, 326 (1919). Moreover, as set forth in XVI.A., above, 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. D.P.U. 15-155, at 383; D.P.U. 15-80/D.P.U. 15-81, at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341.

2. Company Proposal

National Grid proposes an MMRC in the form of a non-bypass-able,[276] fixed monthly charge that would vary according to rate class (Exh. NG-MMRC-1, at 9). The proposed MMRC would be assessed to net metering customers (host customers) that have installed a distributed generation facility and are eligible to receive net metering credits under the Company's net metering provision (Exh. NG-MMRC-1, at 8). The proposed MMRC,

276 In this context, the term "non-bypass-able" means that a customer cannot avoid being assessed the charge by changing his or her usage pattern (Exh. NG-MMRC-1, at 10).

however, would not be assessed to rate class R-2 customers[277] and the Streetlighting rate classes (Exh. NG-MMRC-1, at 9). According to the Company, the proposed MMRC recovers a portion of the fixed costs, allocated to a particular rate class, to ensure the reliability, proper maintenance, and safety of its electric distribution system (Exh. NG-MMRC-1, at 9-10). Further, the Company states that the per-kWh base distribution rate for each rate class will be reduced so that the net effect of the MMRC revenue to be billed and the lower volumetric revenue is revenue neutral to the Company on a class-by-class basis (Exh. NG-MMRC-1, at 21-22).

National Grid states that assessing the MMRC as a non-bypass-able, fixed monthly charge will ensure that customers cannot avoid or reduce the MMRC through usage patterns, and that each customer contributes an appropriate minimum amount towards fixed distribution system costs (Exh. NG-MMRC-1, at 10-11). Moreover, the Company states that the fixed charge is simple for customers to understand and for the Company to administer (Exh. NG-MMRC-1, at 11).

The Company calculated the MMRC rates by first identifying the total demand-related revenue requirement for each rate class based on information contained in the ACOSS (Exh. NG-MMRC-1, at 11, 12-13). The Company then computed the minimum level of demand-related revenue requirement needed to ensure reliability, proper maintenance, and safety of its electric distribution system by comparing maximum non-coincident peak demand

[277] Rate class R-2 is available for general service, residential, low-income customers (MECo, M.D.P.U. No. 1306; Nantucket Electric, M.D.P.U. No. 589).

to the minimum non-coincident peak demand (Exhs. NG-MMRC-1, at 11, 13-14; NG-MMRC-2, at 3). Next, the Company computed the fixed monthly cost-per-customer by dividing the aforementioned reliability portion of the demand-related revenue requirement by the number of annual bills for all customers (Exhs. NG-MMRC-1, at 11, 14-15; NG-MMRC-2, at 3). This amount then was adjusted for rate classes G-2 and G-3,[278] respectively, to account for the portion of demand revenue that is estimated to be eliminated through net metering by these customers (Exhs. NG-MMRC-1, at 11, 15-16; NG-MMRC-2, at 3). Finally, the Company used billing determinants to calculate the proposed MMRC charge for each affected rate class (Exhs. NG-MMRC-1, at 12, 16; NG-MMRC-2, at 3). The proposed MMRC rates are summarized in the table below:

MMRC Rate Component	**R-1**	**R-2**	**R-4**	**G-1**	**G-2**	**G-3**	**S**
Fixed Charge ($/month)	$4.20	n/a	$4.20	$9.50	$28.00	$164.00	n/a

In addition, the Company proposes several tariff revisions to reflect the proposed MMRC charge. Specifically the Company proposes to add a new provision to the tariff for each rate class, add language to its net metering provision, and add the MMRC to the Company's summary of electric delivery rates (Exh. NG-MMRC-1, at 17).

278 Rate class G-2 is available for general service, commercial and industrial, demand customers (MECo, M.D.P.U. No. 1309; Nantucket Electric, M.D.P.U. No. 592). Rate class G-3 is available for general service, commercial and industrial, time-of-use customers (MECo, M.D.P.U. No. 1310; Nantucket Electric, M.D.P.U. No. 593).

3. Positions of the Parties

a. Attorney General

The Attorney General argues that the Department should reject National Grid's rationale that only a fixed monthly charge can ensure that customers contribute to the fixed costs that are incurred to maintain reliability, proper maintenance, and safety of the electric distribution system (Attorney General Brief at 121, citing Exh. NG-MMRC-1, at 10-11). According to the Attorney General, Section 139(j) does not mandate a specific MMRC rate design, nor does it require that the charge be non-bypass-able or unavoidable (Attorney General Brief at 122). Rather, she contends that Section 139(j) explicitly recognizes that an electric distribution company may assess a demand charge if it is based on system peak demand during times of the day determined to be peak hours (Attorney General Brief at 122).[279]

Further, the Attorney General argues that the Department is obligated to consider rate structures that provide strong signals to consumers to decrease energy consumption (Attorney General Brief at 123-124, citing D.P.U. 09-39, at 401-402). In this regard, the Attorney General contends that National Grid's proposed fixed charge seeks to avoid providing

[279] In this regard, the Attorney General asserts that, even if the Department approves the Company's proposal, the Department should find that a fixed charge is not the only method for implementing an MMRC that satisfies the requirements of Section 139(j) and the Department's rate design goals (Attorney General Brief at 124 n.55).

customers with the opportunity to reduce their consumption, and, therefore, is inconsistent with the Department's rate design goal of efficiency (Attorney General Brief at 124).[280]

Finally, the Attorney General argues that, if the Department approves the Company's proposed fixed monthly charge, it should accept the Attorney General's alternative rate design recommendations for rate classes R-1[281] and G-3 (Attorney General Brief at 125-128). With respect to rate class R-1, the Attorney General recommends that the MMRC should be based on the customer's distributed generation facility size (Attorney General Brief at 125).[282] According to the Attorney General, designing the MMRC for residential customers on their facility size, while not as accurate as a volumetric or demand charge, is more appropriately tied to lost revenues that the Company seeks to recover than is a proposed fixed charge

---

280 In particular, the Attorney General argues that because the Company's fixed MMRC charge will have no connection to a customer's actual use of the electric system, customers' incentive to alter their energy use in order to lower their electric bill and the collective peak demand will be diminished (Attorney General Brief at 124, citing Exh. NG-MMRC-2, at 2). Further, the Attorney General contends that Company's proposed MMRC encourages more costs to be recovered through a fixed charge, which she claims typically is used to recover customer-related administrative costs rather than demand- or energy-related costs (Attorney General Brief at 124).

281 Rate class R-1 is available for general service, residential customers (MECo, M.D.P.U. No. 1305; Nantucket Electric, M.D.P.U. No. 588).

282 The Attorney General rejects the Company's claim that it is inappropriate to base MMRC calculations on nameplate capacity (kW) of the distributed generation facility because there are different capacity factors associated with different distributed generation technologies (Attorney General Reply Brief at 41, citing Company Brief at 482). The Attorney General argues that her recommendation is limited to rate class R-1, and that it is unlikely that residential customers would have another type of facility other than solar PV installed on their premises (Attorney General Reply Brief at 41).

because the relative "cost-shift" (i.e., lost revenues of a net metering host customer) is proportional to the size of the distributed generation facility installed (Attorney General Brief at 125, citing Tr. 10, at 1392-1393; Attorney General Reply Brief at 41). The Attorney General asserts that her proposal would result in the Company's collecting an amount of revenue similar to its original proposal (Attorney General Brief at 126).[283] Further, she rejects any notion that the Company's billing system requires substantial upgrades to accommodate her recommended rate design, and she asserts that the Company should be required to provide a full accounting of any such upgrades in its compliance filing (Attorney General Brief at 126-127; Attorney General Reply Brief at 40-41).

Regarding rate class G-3, the Attorney General again reiterates that an MMRC should be used to encourage efficient usage patterns (Attorney General Brief at 127). Thus, she notes that a demand-based charge for this rate class could be designed as a $ per kW charge where $ is the Company's proposed MMRC per customer-month and kW is the average monthly billing demand for net metering customers (Attorney General Brief at 127).[284] The Attorney General asserts that under her recommendation it is reasonable to assume that G-3

---

283 The Attorney General offers her own fixed monthly charge calculation by first taking the Company's proposed fixed monthly charge of $4.20 and dividing it by 6.4 kW, which she claims is the average distributed generation size for rate class R-1, to yield a charge of $0.65625 per kW (Attorney General Brief at 125-126 & n.56). The Attorney General then recommends multiplying the $0.65625 per kW charge by a customer's distributed generation facility size to yield that customer's fixed monthly charge (Attorney General Brief at 126).

284 According to the Attorney General, such a design results in a rate of $0.35 per kW and produces revenue similar to the Company's initial proposal (Attorney General Brief at 127, citing Exhs. AG 39-8 & Att.).

customers would not avoid paying an appropriate share of the fixed costs of the Company's electric distribution system (Attorney General Brief at 127, citing Exh. AG 39-5; RR-AG-39; Attorney General Reply Brief at 42).

b. DOER

DOER argues that the Department should carefully consider the concerns raised by the intervenors when evaluating whether the MMRC reasonably comports with Section 139(j) and Department precedent (DOER Reply Brief at 3). According to DOER, it is critical to the long-term maintenance of the Company's electric distribution system to ensure that all costs are equitably borne by non-net metering and net metering customers (DOER Reply Brief at 4). Thus, DOER argues that the Department should approve the proposed MMRC if the Department finds that the proposed MMRC has (1) just and reasonable costs, (2) meets the requirements of Section 139(j), and (3) meets Department precedent (DOER Reply Brief at 4-5). DOER does recognize, however, the intervenors' concerns about the impact that the proposed MMRC would have on customers, particularly with respect to National Grid's request to charge an MMRC to existing net metering customers (DOER Reply Brief at 5).

c. Acadia Center

Acadia Center argues that in order for the proposed MMRC to satisfy the requirements of Section 139(j), National Grid must quantify both the amount of costs attributable specifically to distributed generation customers and the Company's electric distribution system benefits associated with distributed generation customers in its service territory (Acadia Center Brief at 15, citing D.P.U. 15-155, at 458). According to Acadia

Center, the Company has failed to quantify such costs (Acadia Center Brief at 16). In any event, Acadia Center claims that the evidence shows that most net metering customers already are paying for the reliability, maintenance, and safety of the electric distribution system, and, as such, the Company has failed to demonstrate the need for the proposed MMRC (Acadia Center Brief at 16, citing Exh. NECEC-NP-1 at 52). Therefore, Acadia Center asserts that the Department should reject the proposed MMRC.

Alternatively, Acadia Center argues that, if the Department approves an MMRC, it should only apply prospectively to customers who construct net metering facilities after the Department's Order in this case (Acadia Center Brief at 16). According to Acadia Center, the retrospective aspect of the Company's proposed MMRC proposal violates the rate design principles of efficiency and continuity, as customers who already have invested in a net metering facility cannot react to such a cost by modifying the size of their facility (Acadia Center Brief at 16, citing Exhs. Tesla-KB-1, at 34-35; Tesla-KB-Surrebuttal-1, at 17). Further, Acadia Center asserts that a prospective MMRC charge is more consistent with Department precedent (Acadia Center Brief at 16, citing D.P.U. 17-05-B).

d. NECEC

Similar to Acadia Center, NECEC argues that most net metering customers already are contributing to the fixed costs of ensuring the reliability, maintenance, and safety of the Company's electric distribution system (NECEC Brief at 31-32, citing Exhs. NECEC-NP-1, at 47-52; NG-MMRC-Rebuttal-1, at 3-4; NECEC-NP-Surrebuttal at 15-17; Tr. 10, at 1445-48; NECEC Reply Brief at 8-9). Therefore, NECEC contends that the Company has not met its burden under Section 139(j), as the costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system already are allocated and offset (NECEC Brief at 31-32). NECEC also claims that the proposed MMRC will cause a dramatic increase to the typical residential net metering customer's annual bill from $21 to $71 (NECEC Brief at 31, citing Exh. NG-MMRC-2, at 5; Tr. 10, at 1429). For these reasons, NECEC asserts that the MMRC excessively burdens ratepayers and should not be approved (NECEC Brief at 32; NECEC Reply Brief at 9).

e. Tesla

Tesla argues that the proposed MMRC fails to meet the purpose of Section 139(j), which it claims is to require that net metering customers pay their share of the fixed costs of the reliability portion of the Company's electric distribution system (Tesla Brief at 9-10). Similar to the argument raised by Acadia Center and NECEC, Tesla claims that most net metering customers (with the exception of those net metering customers in rate class G-1) already are paying bills at levels that are generally well above the proposed MMRC (Tesla Brief at 10, citing Exhs. NECEC-NP-1, at 52; NECEC-NP-Surrebuttal-1, at 16). Thus, Tesla asserts that any further charge on net metering customers is inappropriate (Tesla Brief at 10).

Tesla also argues that the proposed MMRC is inconsistent with several of the specific provisions in Section 139(j) (Tesla Brief at 10-11; Tesla Reply Brief at 9). First, Tesla contends that the proposed MMRC does not capture the cost of the reliability component of the Company's electric distribution system, and, consequently, the total revenue captured by the proposed MMRC would not equal the Company's alleged "lost sales" attributable to net metering[285] (Tesla Brief at 11, citing Tr. 10, at 1455-1456; RR-Tesla-2; Tesla Reply Brief at 9). Accordingly, Tesla asserts that the proposed MMRC fails to offset "reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system" as required by Section 139(j) (Tesla Brief at 11; Tesla Reply Brief at 9). Second, Tesla argues that the proposed MMRC is essentially symbolic and fails to accurately price the amount, if any, by which net metering customers are purportedly failing to contribute to the fixed costs of the reliability portion of the Company's electric distribution system (Tesla Brief at 12; Tesla Reply Brief at 9). Accordingly, Tesla asserts that the proposed MMRC fails to achieve an "equitable allocation of fixed costs" as required by Section 139(j) (Tesla Brief at 12; Tesla Reply Brief at 9).

Next, Tesla argues that the Company's proposal fails to meet several of the Department's long-standing rate design goals (Tesla Brief at 12). In particular, Tesla contends that the proposed MMRC produces bill increases of up to 200 percent in contravention of the Department's rate design goal of continuity (Tesla Brief at 12-13, citing Tr. 10, at 1429). In addition, Tesla claims that the proposed MMRC rate is unfair and inefficient, as existing customers are unable to adjust their behavior to avoid or reduce the MMRC, and, therefore, customers are unable to respond to price signals (Tesla Brief at 14).

285 Specifically, Tesla asserts that the Company conceded that the proposed MMRC would produce only about 0.37 percent of the total revenue needed for the residential rate class, and only 0.1255 percent of the revenue requirement for rate class G-1 (Tesla Brief at 11, citing Tr. 10, at 1456).

Tesla also argues that the Company's proposed MMRC "fee" to existing net metering customers is novel and distinguishable from instances where fees were applied retroactively to net metering customers in other jurisdictions (Tesla Brief at 14-15). According to Tesla, applying the proposed MMRC charge to existing net metering customers would punish those customers for their efforts to "reduce the state's carbon footprint" (Tesla Reply Brief at 8). Moreover, Tesla contends that Section 139(j) does not preclude a "prospective only" MMRC and that the Department previously approved a proposed MMRC that would have exempted existing net metering customers, notwithstanding statutory language purporting to constrain the Department's ability to unilaterally exempt non-low-income customers (Tesla Brief at 15, citing D.P.U. 17-05-B at 132-133). Thus, Tesla asserts that the Department has the authority to exempt existing net metering customers from an approved MMRC (Tesla Brief at 15; Tesla Reply Brief at 10). Finally, Tesla argues that, notwithstanding the requirements of Section 139(j), based on the above considerations, the Company's proposed MMRC does not result in just and reasonable rates (Tesla Brief at 17; Tesla Reply Brief at 9-10).

f. Company

National Grid argues that its MMRC proposal complies with the statutory requirements of Section 139(j) and, therefore, should be approved (Company Brief at 477; Company Reply Brief at 155, 162). In particular, the Company contends that the proposed MMRC is designed to ensure that distributed generation customers are contributing a share of the fixed costs of its electric distribution system, and that a non-bypass-able charge is the best way to guarantee this contribution and comply with Massachusetts law (Company Brief at 479; Company Reply Brief at 160-161).

The Company takes issue with the Attorney General's claim that the proposed MMRC violates the Department's goal of efficiency (Company Brief at 480). In particular, the Company argues that Attorney General fails to recognize that the fixed costs of ensuring the reliability, proper maintenance, and safety of its electric distribution system are not linked to a particular customer's usage (Company Brief at 480). According to National Grid, such costs do not vary based on whether a customer draws little or no net electricity from the distribution system, because the system is designed to meet peak demand (Company Brief at 480-481, citing Exh. NG-MMRC-1, at 10).

National Grid also challenges the Attorney General's recommendation that, if the Department approves the fixed charge MMRC, the Company should base the fixed charge MMRC for rate class R-1 customers on distributed generation facility size (Company Brief at 481). The Company argues that its billing system does not contain the nameplate capacity rating for host net metering customers, and the cost of upgrading the billing system to accommodate the Attorney General's recommendation is unreasonable and overly burdensome to customers (Company Brief at 481-482, citing Exh. AG 39-5; Tr. 10, at 1398-1399; Company Reply Brief at 159-160, citing Exhs. DPU-NG 3-13; DPU-NG 16-2; AG 39-6). Moreover, the Company contends that nameplate capacity is not the defining characteristic of a distributed generation facility, as there are different capacity factors associated with different distributed generation technologies (Company Brief at 482).[286]

Further, National Grid disagrees with the Attorney General's recommended demand-based charge for rate class G-3 (Company Reply Brief at 160-161). According to the Company, if the MMRC charge were based on peak demand, the net metering facility could allow a customer to change usage patterns and reduce or avoid the charge (Company Brief at 479; Company Reply Brief at 160-161). National Grid argues that, in such a scenario, the customer would not be contributing a fair share of the fixed costs of the Company's electric distribution system, thereby defeating the purpose of the MMRC and Section 139(j) (Company Brief at 479; Company Reply Brief at 161).

In response to Acadia Center's argument that the proposed MMRC does not quantify the costs attributable to distributed generation customers and the distribution system benefits associated with distributed generation customers, the Company states that Acadia Center's reliance on D.P.U. 15-155 is misplaced, as the statutory framework under which the proposed MMRC is being evaluated is distinguishable from the issues presented in D.P.U. 15-155 (Company Brief at 482-483, citing D.P.U. 15-155, at 511-512). According to National Grid, the Department has explicitly made clear that that Section 139(j) does not

286 For example, the Company notes that the production profile of an intermittent resource such as solar PVs, which is variable due to the weather, is different than a co-generation facility (Company Brief at 482, citing Tr. 10, at 1426). Further, the Company asserts that the cost per kW of each facility varies because the savings will differ depending upon the size of the unit and the technology type (Company Brief at 482, citing Tr. 10, at 1411-1412).

require a proven cost shift or a determination regarding the possible benefits of net metering facilities as a prerequisite to approve an MMRC (Company Brief at 483, citing D.P.U. 17-05-B at 134).

National Grid also rejects the arguments of Acadia Center, NECEC, and Tesla that the proposed MMRC is not warranted because most net metering customers already are paying for the reliability, proper maintenance, and safety of the electric distribution system (Company Brief at 483, citing Acadia Center Brief at 16; NECEC Brief at 31; Tesla Brief at 10). In particular, the Company asserts that the NECEC's analysis comparing total bills to the MMRC is flawed because the total bills include a number of charges that are not related to base distribution rates (Company Brief at 484; Company Reply Brief at 158). Further, the Company asserts that its own analysis demonstrates that a significant portion of net metering customers did not pay the minimum contribution amount, and that 80 percent of those customers did not pay the costs that they imposed on the Company's electric distribution system (Company Brief at 484, citing Exh. NG-MMRC-Rebuttal-1, at 3-4; Company Reply Brief at 158).

National Grid also disagrees with the notion that its proposed MMRC should be applied only prospectively (Company Brief at 485, citing Acadia Center Brief at 16; NECEC Brief at 30-31; Tesla Brief at 15-16). According to National Grid, exempting existing net metering customers from the proposed MMRC charge would be inconsistent with the purpose of the MMRC, which the Company claims is to ensure that all customers contribute to the fixed costs of ensuring the reliability, proper maintenance, and safety of the electric distribution system (Company Brief at 485).[287] Further, the Company rejects Tesla's contention that retroactive application of the proposed MMRC charge would punish early adopters of distributed generation (Company Reply Brief at 156). According to the Company, the proposed MMRC charge is not punitive to existing net metering customers because they will continue to experience significant bill reductions due to displaced energy and to the net metering credits paid for by all customers (Company Reply Brief at 156, citing Exh. NG-MMRC-Rebuttal-1, at 3-4, 9-10; Tr. 10, at 1429-1430).

National Grid takes issue with several additional arguments raised by Tesla. In particular, the Company disputes that customer bill increases associated with the proposed MMRC conflicts with the Department's goal of rate continuity and does not result in just and reasonable rates (Company Brief at 485, citing Tesla Brief at 13; Company Reply Brief at 157). According to the Company, Tesla's argument is without merit and misleading because it fails to recognize that current net metering customers are not paying a fair share of distribution system costs, and it does not account for the savings that distributed generation customers realize from net metering benefits (Company Brief at 485-486; Company Reply Brief at 157). Further, National Grid rejects Tesla's argument that the proposed MMRC revenue would not add up to the Company's lost sales amount attributable to net metering

[287] In this regard, the Company also disagrees with Tesla's categorizing of the proposed MMRC charge as a "fee" on existing net metering customers (Company Brief at 486, citing Tesla Brief at 14-15). National Grid asserts that the proposed MMRC charge is not a fee, but rather a charge to ensure that net metering customers are paying their fair share of the costs that enable them to take advantage of the electric distribution system and net metering benefits (Company Brief at 486).

(Company Brief at 486, citing Tesla Brief at 11). The Company argues that Tesla's assertion is irrelevant and misconstrues the purpose of Section 139(j), which is not to provide for the recovery of lost revenues, but to ensure that all customers are contributing a fair share of the fixed costs of the electric distribution system (Company Brief at 486).

In addition, National Grid disagrees with Tesla's contentions that the proposed MMRC will not offset reasonable and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the Company's electric distribution system (Company Reply Brief at 156, citing Tesla Reply Brief at 9). In this regard, the Company asserts that costs reflected in the proposed MMRC include only demand-related costs and only the reliability portion of those costs as measured by each rate class's minimum use of the system (Company Reply Brief at 157, citing Exh. NG-MMRC-1, at 21-22; Tr. 10, at 1422). Further, the Company contends that the per-kWh base distribution rate for each rate class will be reduced so that the net effect of the MMRC revenue to be billed and the lower volumetric revenue is revenue neutral on a class-by-class basis (Company Reply Brief at 157, citing Exh. NG-MMRC-1, at 21-22).

4. Analysis and Findings

As noted above, pursuant to Section 139(j), the Department may approve an MMRC that: (1) equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (2) does not excessively burden ratepayers; (3) does not unreasonably inhibit the development of Class I, Class II, and Class III net metering facilities; and (4) is dedicated to offsetting reasonably and prudently incurred costs necessary to maintain the reliability, proper maintenance, and safety of the electric distribution system. Section 139(j). National Grid argues that it has met each of these statutory requirements and that its MMRC results in just and reasonable rates (Company Brief at 477-486; Company Reply Brief at 155-157). Several intervenors disagree and take issue with the proposed fixed customer charge and/or claim that the Company's MMRC is inconsistent with Section 139(j), is unnecessary, and would not result in just and reasonable rates (Attorney General Brief at 121-127; Attorney General Reply Brief at 40-42; Acadia Center Brief at 15-16; NECEC Brief at 31-32; NECEC Reply Brief at 8-9; Tesla Brief at 9-17; Tesla Reply Brief at 9-10).

National Grid's filing represents the Department's second opportunity to evaluate a proposed MMRC. In D.P.U. 17-05, the Department approved for NSTAR Electric an MMRC that was a combination of a higher customer charge, a demand charge, and a lower volumetric rate compared to the otherwise applicable non-MMRC rate design. D.P.U. 17-05-B at 101-105, 128-156. NSTAR Electric's MMRC applied to residential and C&I net metering customers interconnected on or after December 31, 2018. D.P.U. 17-05-B at 102, 153.[288] NSTAR Electric, however, never implemented the MMRC charge due to the Legislature's amendment of Section 139(j) in November 2018, and the Department's concerns that NSTAR Electric sought to improperly modify its MMRC through proposed post-Order changes to its net metering tariff. See D.P.U. 17-05, Hearing Officer Memorandum at 3-4 (August 29, 2018). As a result of these two events, the Department

---

288 The Department directed NSTAR Electric to include an exemption from the MMRC charge for low-income host customers. D.P.U. 17-05-B at 152-153.

directed NSTAR Electric to refrain from charging an MMRC rate until after the Department approved an MMRC that fully complied with Section 139(j), as amended. D.P.U. 17-05, Hearing Officer Memorandum at 3-4. In this regard, the Department opened a new docket, D.P.U. 18-72, to allow NSTAR Electric to file a revised MMRC and affected tariffs. D.P.U. 17-05, Hearing Officer Memorandum at 4. As of the date of this Order, the Department has not received a new filing from NSTAR Electric.

National Grid's proposed MMRC is materially different from the MMRC approved in D.P.U. 17-05-B. For example, National Grid's MMRC proposal takes the form of a non-bypass-able fixed charge, which attempts to prevent customers from avoiding the MMRC by reducing their demand, and does not include a demand charge component (Exhs. NG-MMRC-1, at 10; NG-MMRC-2, at 3; DPU-NG 3-8; DPU-NG 3-9; DPU-NG 3-16(b); AG 39-1; Tr. 10, at 1410). Further, in contrast to NSTAR Electric's MMRC, National Grid's proposal does not adjust the incremental volumetric or demand rate for net metering customers within each rate class to account for some of the demand-related costs the net metering customers would pay through the MMRC (Exh. NG-HSG-6, at 2-6). D.P.U. 17-05-B at 3. In addition, as noted above, NSTAR Electric's MMRC was prospective in nature and intended to apply to net metering customers who interconnected after a date certain (i.e., December 31, 2018), whereas National Grid proposes to apply the MMRC to certain existing and new net metering customers (Exh. NG-MMRC-1, at 8; Tr. 10, at 1415).

Although Section 139(j) does not prescribe a specific MMRC rate structure, or require uniformity among MMRC proposals, the Department has expressed a strong preference for electric distribution companies to jointly propose and develop changes to the net metering program and associated incentive programs, so that there is consistency among proposals and, if approved, uniformity in implementation. See, e.g., 220 CMR 18.00; Net Metering and SMART Tariff Compliance, D.P.U. 19-24 (Stamp Approval, June 3, 2019); D.P.U. 17-146-A at 4, 47; D.P.U. 17-146-B at 81 n.72; D.P.U. 17-140-A at 192; D.P.U. 17-22-A at 47, 57; Investigation into the Interconnection of Distributed Generation, D.P.U. 11-75-E at 1, 29-40 (2013); Net Metering and Interconnection of Distributed Generation, D.P.U. 11-11-A at 4, 19-20 (2012). To this end, in 2016, the Department sought comments from and convened technical conferences with National Grid, NSTAR Electric, Unitil, and a group of non-utility company stakeholders in an attempt to develop a model MMRC. D.P.U. 16-64-E at 1-2. At that time, Section 139(j) set a deadline for an MMRC to take effect not later than December 31, 2018. D.P.U. 16-64-E at 4. Ultimately, the Department decided not to open a separate adjudicatory proceeding to address a generic structure for an MMRC that would apply to all electric distribution companies, but rather chose to evaluate individual MMRC proposals if filed by the electric distribution companies. D.P.U. 16-64-E at 22-23.

Since the proceedings in docket D.P.U. 16-64, the Department has fully adjudicated two very different MMRC proposals. Further, Section 139(j) has been amended to remove any deadline associated with MMRC approval. Given the Department's experience with

NSTAR Electric's MMRC proposal, after careful review of National Grid's proposal and the record in this proceeding,[289] and in light of the net metering-related considerations discussed above, the Department concludes that the public interest would be best served by considering a standardized rate structure that is consistent with the objectives of Section 139(j) and applicable to net metering customers across the electric distribution companies' entire service areas. We find that a standardized rate structure for net metering customers would better maximize the Department's long-standing rate design goals, in particular efficiency, simplicity, and fairness. D.P.U. 15-155, at 455; D.P.U. 15-80/D.P.U. 15-81 at 294; D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341. Further, while we recognize that the previous efforts at developing a model MMRC did not produce a uniform result, we find that the subsequent proposals filed by NSTAR Electric in D.P.U. 17-05 and National Grid in the instant proceeding provide a strong foundation and opportunity to identify the various issues to be addressed in developing a standardized rate structure applicable to net metering customers.

---

289 E.g., Exhs. NG-MMRC-1, at 1-24; NG-MMRC-2 through NG-MMRC-4; NG-MMRC-Rebuttal-1, at 1-11; NECEC-NP-1, at 46-54; NG-NP-Surrebuttal-1, at 15-17; Tesla-KB-1, at 28-38; Tesla-KB-4 through Tesla-KB-5; Tesla-KB-Surrebuttal-1, at 15-18; DPU-NG 3-4 through DPU-NG 3-17; DPU-NG 16-1 through DPU-NG 16-8; DPU-NG 22-1 through DPU-NG 22-19; AG 19-1 through AG 19-6; AG 39-1 through AG 39-12; NECEC 1-52 through NECEC 1 -60; NECEC 2-1; Tr. 10, at 1386-1480; RR-DPU-28 through RR-DPU-30; RR-AG-32 through RR-AG-34; RR-Tesla-2.

Based on the above findings, and in light of the discretion afforded the Department pursuant to Section 139(j),[290] we decline to approve National Grid's MMRC proposal at this time. Rather, we encourage National Grid to consider filing with NSTAR Electric and Unitil a joint proposal for establishing a standardized rate structure that is consistent with the objectives of Section 139(j) and applicable to net metering customers across the electric distribution companies' entire service areas.[291] Our decision today is not a rejection of a fixed monthly charge or a preference for one type of rate structure over another. On the contrary, the Department encourages National Grid in its discussions with NSTAR Electric and Unitil to explore all rate structure alternatives (e.g., new net metering rate classes) that seek to ensure the reliability, proper maintenance, and safety of the electric distribution

---

[290] Pursuant to Section 139(j), the Department "may approve an MMRC" that satisfies the provisions of the statute. Based on the plain meaning of the word "may" in Section 139(j), the Department concludes that it is not required to approve National Grid's proposed MMRC. See, e.g., NSTAR Gas Company, D.P.U. 14-135, at 140-141 (2016); Cambridge Electric Light Company, D.T.E. 98-24, at 9-10 (1998); see also Globe Newspaper Company v. Superior Court, 379 Mass. 846, 863 n.22 (1980) ("The Legislature clearly knows the difference between the permissive 'may' and the mandatory 'shall'"); Town of Milton v. Personnel Administrator of the Department of Personnel Administration, 406 Mass. 818, 828 (1990) (recognizing the distinction between a mandatory "shall" and a permissive "may"). Moreover, the Department has broad authority to design and set rates pursuant to G.L. c. 164, and 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. 334 Mass. 477; 376 Mass. 294, 302; 379 Mass. 408.

[291] As noted above, the Department opened docket D.P.U. 18-72 to allow NSTAR Electric to file a revised MMRC and affected tariff(s). D.P.U. 17-05, Hearing Officer Memorandum at 4. In light of today's Order, the Department does not expect NSTAR Electric to make such a filing in docket D.P.U. 18-72.

system. We stress, however, that the objective of any joint proposal is rate structure uniformity among the Commonwealth's electric distribution companies.

The Department expects any joint proposal to be submitted as a revenue neutral rate design filing, supported by appropriate cost of service data and bill impact analysis across all rate classes for each electric distribution company. Further, the Department expects any joint proposal to address the impacts on the successful development of on-site generation (e.g., net metering facilities) and to be consistent with the Department's long-standing rate structure goals. Finally, the Department expects that, in preparing any joint proposal, the electric distribution companies will consider the concerns raised by the various commenters and intervenors in D.P.U. 16-64, D.P.U. 17-05, and the instant case. To the extent the Department receives a joint filing and determines that an adjudicatory proceeding is warranted, the Department will provide an opportunity for interested parties to participate.

F. Rate-by-Rate Analysis

1. Introduction

The basic components of the Company's service delivery rates are the customer charge, which is a fixed monthly amount, and the distribution charge, which is based on monthly usage (kWh).[292] C&I customers are also charged for demand (kW). The Department must determine, on a rate class by rate class basis, the proper level at which to set the customer charge and delivery charges for each rate class, based on a balancing of our

[292] Rates for street lighting service have a different rate design (see Section XVI.F.7., below).

rate structure goals. 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. See, e.g., D.T.E. 03-40, at 384; D.T.E. 02-24/25, at 256; D.T.E. 01-56, at 139; D.P.U. 92-250, at 193-194; D.P.U. 92-210, at 214. This allocation method satisfies the Department's rate structure goal of fairness. Nonetheless, the Department must balance our goal of fairness with our goal of continuity. For this balancing, we have reviewed the changes in total revenue requirements by rate class and bill impacts by consumption level within rate classes. Based on its initial filing, the Company designed rates to produce a revenue requirement for distribution service of $864,418,933 (Exh. NG-RRP-5, at 10). The Company proposed its rate design with the stated goal of designing fair and equitable distribution rates across all rate classes to reflect the actual cost to serve each customer (Exh. NG-HSG-1, at 24). In ruling on National Grid's rate design proposals, the Department considers its rate structure goals: to achieve efficiency and simplicity as well as to ensure continuity of rates, fairness between rate classes, and corporate earnings stability. D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401.

2. Rate R-1 and Rate R-4

a. Company Proposal

Rate R-1 is available to all residential customers (Exh. NG-HSG-1, at 25). National Grid proposes to increase the monthly customer charge from $5.50 per month to $7.00 per month (Exh. NG-HSG-1, at 25). The per-kWh charge is calculated as the total class revenue requirement less the revenue recovered through the proposed customer charge and the MMRC, divided by the adjusted test year kWh deliveries (Exhs. NG-HSG-1, at 25-26; NG-HSG-6, at 2).

Rate R-4 is a residential time-of-use rate class and is optional for customers whose use exceeds 2,500 kWh per month for a twelve-month period (Exhs. NG-HSG-1, at 26; DPU-NG 21-7). The Company does not propose any changes to structure of the Rate R-4 (Exh. NG-HSG-1, at 26). The Company proposes to maintain the customer charge of $20.00 per month, as well as the ratio of the peak and off-peak kWh rates (Exh. NG-HSG-1, at 26-27).

b. Positions of the Parties

i. Attorney General

The Attorney General does not oppose the relative increases to the customer and usage charges under the Company's proposed revenue requirement (Attorney General Brief at 114). The Attorney General takes issue with the Company's proposal to increase the residential customer charge to $7.00 regardless of the amount of revenue increase found reasonable by the Department (Attorney General Brief at 114, citing Exh. NG-HSG-Rebuttal-1, at 4). The Attorney General claims that this proposal would violate the rate design principle of producing moderate and reasonable bill impacts by potentially creating a large disparity between the customer charge increase and the usage charge increase (Attorney General Brief at 114-116, citing Exh. AG-SJR-Surrebuttal-2; D.P.U. 17-05-B at 278). Therefore, the Attorney General argues that the Department should apply any reduction to the proposed revenue requirement proportionately between the two charges (Attorney General Brief at 116).

The Attorney General also proposes that the Company's current R-4 rate class be eliminated (Attorney General Brief at 112). The Attorney General claims that the current Rate R-4, which is an optional time-of-use rate for residential customers, is used only by 150 customers, or 0.01 percent, of all residential customers (Attorney General Brief at 112, citing Exh. NG-HSG-6, at 2). The Attorney General explains that the low adoption rate is in part due to a very high minimum usage requirement, a very high customer charge, and the rate design (Attorney General Brief at 112, citing Exh. NG-HSG-6, at 3). In addition, the Attorney General claims that more than half of those currently on the rate do not meet the minimum usage requirement to be eligible for the rate (Attorney General Brief at 113, citing Exh. AG-SJR-1, at 15). Further, the Attorney General asserts that 64 of the 72 customers who are both using and eligible for the rate paid more on the Rate R-4 than they would have paid on the standard residential Rate R-1 (Attorney General Brief at 113, citing Exh. AG-SJR-1, at 17). The Attorney General argues that the current Rate R-4 has serious problems with both its design and administration, and it should, therefore, be eliminated (Attorney General Brief at 113). The Attorney General emphasizes that she supports a well-designed time-of-use option for residential customers and that the elimination of the current Rate R-4 should not foreclose the Company, or any other party, from proposing a well-designed time-of-use rate for residential customers in the future (Attorney General Brief at 113).

ii. Company

The Company claims that the $7.00 residential customer charge is closer to actual costs to serve customers and rejects the Attorney General's arguments against this increase as misrepresentative (Company Brief at 488; Company Reply Brief at 163). The Company argues that the proposed change to the customer charge brings residential rates closer in line with customer charges approved by the Department for other electric distribution companies (Company Brief at 488, citing Exh. NG-HSG-1, at 26). The Company also asserts that low-income customers will see a muted increase in the customer charge because of the proposed increase to the low-income discount (Company Brief at 488; Company Reply Brief at 163).

Regarding the elimination or redesign of the Rate R-4, the Company states that it would not object to eliminating the Rate R-4 (Company Reply Brief at 163, citing Exh. NG-HSG-Rebuttal-1, at 3; Tr. 10, at 1365-1366). Regarding a redesign of the residential time-of-use rate, the Company argues that such action stemming directly from this case would be premature and would frustrate the Department's stated preference (Company Brief at 487, citing D.P.U. 15-120, at 133, 135).

c. Analysis and Findings

i. Rate R-1

The Company is proposing to increase the customer charge for the R-1 residential customer classes from $5.50 per month to $7.00 per month (Exh. NG-HSG-1, at 25). This increase is a significant movement towards the customer-related cost to serve, which is $9.84

per month (Exhs. NG-HSG-1, at 25; NG-HSG-2C, line 21). The Attorney General does not oppose the Company's proposal to move residential customer charges towards cost of service (Exh. AG-SJR-Surrebuttal-1, at 2). Nonetheless, if the Department approves a revenue requirement below the amount proposed, the Company recommends that the customer charge remain at $7.00 unless the ACOSS determines the cost to serve is lower (Exh. NG-HSG-Rebuttal-1, at 4). The Attorney General recommends that the proposed customer charge should be reduced in proportion to any reduction in the residential class's share of the revenue requirement (Exh. AG-SJR-Surrebuttal-1, at 2-3).

The Department's long-standing policy regarding rate structure has been to balance our goals of rate continuity and fairness as it relates to the cost to serve. D.P.U. 13-75, at 330; D.P.U. 12-25, at 444; D.P.U. 10-114, at 341; D.P.U. 09-39, at 401; D.T.E. 03-40, at 365; D.T.E. 02-24/25, at 252; D.T.E. 01-56, at 134. In setting the residential customer charge in this case, the Department has taken into consideration the concerns of both the Company and the Attorney General as well as a balancing of our rate structure goals and bill impacts. Based on these considerations, the Department finds the Rate R-1, designed with an increase in the monthly customer charge from $5.50 to $7.00 and the Company's proposed method for establishing the volumetric charge for Rate R-1, subject to our findings on the MMRC, 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. 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 Company is directed to set the monthly customer charge at $7.00 per month and to set its volumetric charge to collect the remaining class revenue requirement approved in this Order, truncated at five decimal places.

ii. Rate R-4

The Company has proposed to maintain the R-4 rate class, which is an optional time-of-use rate for residential customers, with no significant changes to its rate design (Exhs. NG-HSG-1, at 26; NG-HSG-13, Proposed M.D.P.U. Nos. 1375 (MECo), 612 (Nantucket Electric) (Bates Stamp 6, 66)). As an initial matter, of the approximately 1.2 million residential customers on the Company's system during the test year, only 161 customers took service from Rate R-4 during the test year (Exhs. NG-HSG-6, at 1-2; AG-SJR-1, at 15). Additionally, of those customers that took service from Rate R-4, over half did not meet the eligibility requirements to be served under the rate because they used less than 2,500 kWh each month and only eight eligible customers saw savings under the Rate R-4 as compared to the standard R-1 residential rate (Exh. AG-SJR-1, at 17). The Department finds that the Rate R-4, as currently designed, does not provide an adequate savings incentive to a significant number of customers. The Department, therefore, directs the Company to eliminate the R-4 rate class (Exh. NG-HSG-13, Proposed M.D.P.U. Nos. 1375 (MECo), 612 (Nantucket Electric) (Bates Stamp 6, 66)). Customers currently billed under the R-4 rate class shall be moved to the residential R-1 rate class. For purposes of rate design, the Department has included the revenues associated with R-4 customers in the R-1 rate class. Therefore, the Company is directed to eliminate the R-4 rate class and migrate those customers previously on Rate R-4 to its Rate R-1. We acknowledge that the Company will need to notify its customers of the elimination of Rate R-4. Accordingly, the Company shall provide with its compliance filing a proposed customer notification to be included in the first bill and to the extent possible sent via email to all Rate R-4 customers.

The Department supports the implementation of well-designed residential time-of-use rates that are consistent with our rate structure goals and that promote energy efficiency. In establishing a framework for time varying rates for basic service, we noted that changing to time varying rates would require significant customer outreach, marketing, and education to engage customers and provide them with simple, clear information about what time varying rates mean for their electric rates. Investigation into Time Varying Rates, D.P.U. 14-04-C at 19 (2014). The same education is needed when implementing residential time-of-use rates for base distribution service. Therefore, while we encourage proposals for such rates in the future, we expect the Company to engage in the appropriate customer outreach to ensure consumers are able to take advantage of the most appropriate rate for them.

3. Rate R-2

a. Company Proposal

Rate R-2 is available to low-income residential customers who meet the criteria for the discount (Exh. NG-HSG-1, at 25). A customer will be eligible for this rate upon verification of the customer's receipt of any means-tested public benefit program or verification of eligibility for the low-income home energy assistance program or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income (Exh. NG-HSG-13, Proposed M.D.P.U. Nos. 1374 (MECo) and 611 (Nantucket Electric) (Bates Stamp 4, 64)). Rate design for Rate R-2 is the same as Rate R-1, for they are treated as one customer class group for rate design purposes, except customers on Rate R-2 currently receive a 29-percent discount off their entire bill (Exh. NG-HSG-1, at 34). As discussed above, the Company proposes to increase the discount to 32 percent (Exh. NG-HSG-1, at 34). The Company's residential assistance adjustment factor, which operates outside of base distribution rates on a reconciling basis, recovers from all customers the low-income discount and arrears forgiven under the Company's arrearage management program (Exh. NG-HSG-9).

b. Analysis and Findings

As stated above, the rate design for Rate R-2 is the same as Rate R-1 because they are treated as one customer class group for rate design purposes. Therefore, the distribution charges for Rate R-2 shall be the same as the charges for Rate R-1. In addition, as discussed above, the Company's proposed discount rate of 32 percent is allowed and the resulting revenue shortfall will be recovered through the residential assistance adjustment factor.

4. Rate G-1

a. Company Proposal

Rate G-1 is available to C&I customers who have average use that does not exceed 10,000 kWh per month or 200 kW of demand (Exh. NG-HSG-1, at 27). The Company proposes to maintain the customer charge at $10.00 per month (Exh. NG-HSG-1, at 27). In addition, the Company proposes to maintain the unmetered Rate G-1 location service charge at $7.50 per month (Exhs. NG-HSG-1, at 27-28; NG-HSG-13, Proposed M.D.P.U. Nos. 1376 (MECo), 613 (Nantucket Electric) (Bates Stamp 9, 69)). The Company also proposes to set the monthly minimum charge equal to the customer charge; however, if the kv amperes ("kVA") transformer capacity needed to serve a customer exceeds 25 kVA, the minimum charge will be increased for each kVA in excess of 25 kVA (Exh. NG-HSG-1, at 27-28). The Company proposes to increase this charge from $2.11 per kVA to $2.50 per kVA (Exh. NG-HSG-1, at 28). The per-kWh charge is calculated as the total class revenue requirement less the revenue recovered through the proposed customer charge, minimum bill provision, and the MMRC, divided by the adjusted test year kWh deliveries (Exhs. NG-HSG-1, at 28; NG-HSG-6, at 4).

b. Analysis and Findings

According to the Company's ACOSS, the customer-related cost to serve the G-1 rate class is $11.26 per month (Exhs. NG-HSG-1, at 27; NG-HSG-2C, line 21). Based on a review of the bill impacts on customers, the Department finds Rate G-1, designed to maintain the monthly customer charge of $10.00 and the unmetered location service charge of $7.50 per month, satisfies continuity goals and produces bill impacts that are moderate and reasonable. The Department finds the increase to the kVA component of the minimum charge to $2.50 per kVA satisfies continuity goals and is reasonable. The Department finds that the Company's proposed method for establishing the volumetric charge for Rate G-1, subject to our findings on the MMRC, 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. 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 Company is directed to set the monthly customer charge at $10.00 and to set its volumetric charge to collect the remaining class revenue requirement approved in this Order, truncated at five decimal places.

5. Rate G-2

a. Company Proposal

Rate G-2 is available to C&I customers who have average consumption greater than 10,000 kWh, but do not exceed 200 kW of demand (Exh. NG-HSG-1, at 28). National Grid proposes to increase the customer charge for Rate G-2 customers from $25.00 per month to $30.00 per month (Exhs. NG-HSG-1, at 28; NG-HSG-6, at 5). The Company proposes to increase the demand charge from $8.50 per kW to $10.60 per kW (Exhs. NG-HSG-1, at 28; NG-HSG-6, at 5). Additionally, the Company proposes a set of high voltage metering discounts for those taking service at a higher voltage (Exhs. NG-HSG-1, at 29). The per-kWh charge is calculated as the total class revenue requirement less the above charges and the MMRC, divided by the adjusted test year kWh deliveries (Exhs. NG-HSG-1, at 28; NG-HSG-6, at 5).

b. Analysis and Findings

According to the Company's ACOSS, the customer-related cost to serve the G-2 rate class is $36.78 per month (Exhs. NG-HSG-1, at 28; NG-HSG-2C, line 21). Based on a review of the bill impacts on customers, the Department finds that the monthly customer charge, proposed to increase from $25.00 to $30.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable. According to the Company's ACOSS, the demand-related cost to serve the G-2 rate class is $12.04 per kW (Exhs. NG-HSG-1, at 28; NG-HSG-2C, line 8). Based on a review of the bill impacts on customers, the Department finds the demand charge, proposed to increase from $8.50 per kW to $10.60 per kW, satisfies continuity goals and produces bill impacts that are moderate and reasonable. The Department also finds that the high voltage metering discounts satisfy continuity goals and are reasonable. The Department finds that the Company's proposed method for establishing the volumetric charge for Rate G-2, subject to our findings on the MMRC, 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. 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 Company is directed to set the monthly customer charge at $30.00, the demand charge at $10.60 per kW and to set its volumetric charges to collect the balance of the class revenue requirement approved in this Order based, truncated at five decimal places.

6. Rate G-3

a. Company Proposal

Rate G-3 is available to C&I customers who have average use that exceeds 200 kW of demand (Exh. NG-HSG-1, at 29). The Company proposes to maintain the current G-3 customer charge of $223.00 per month (Exh. NG-HSG-1, at 30). The Company also proposes to increase the demand charge from $5.76 per kW to $7.60 per kW. Additionally, the Company proposes a set of high voltage metering discounts for those taking service at a higher voltage level and who have second feeder service (Exhs. NG-HSG-1, at 30; NG-HSG-2C-1; NG-HSG-7, lines 4-6). The on-peak kWh charge is calculated as the total class revenue requirement less the above charges and the MMRC, divided by the adjusted test year kWh deliveries (Exhs. NG-HSG-1, at 30; NG-HSG-6, at 6). There is no off-peak kWh charge for Rate G-3 (Exh. NG-HSG-1, at 30).

b. <u>Analysis and Findings</u>

According to the Company's ACOSS, the monthly customer-related cost to serve the G-3 rate class is $193.46 (Exhs. NG-HSG-1, at 30; NG-HSG-2C, line 21). Based on a review of the bill impacts on customers, the Department finds the customer charge, proposed to be maintained at $223.00, satisfies continuity goals and produces bill impacts that are moderate and reasonable. According to the Company's ACOSS, the demand-related cost to serve the G-3 rate class is $8.91 per kW (Exhs. NG-HSG-1, at 30; NG-HSG-2C, line 8). Based on a review of the bill impacts on customers, the Department finds the demand charge, proposed to increase from $5.76 per kW to $7.60 per kW, satisfies continuity goals and produces bill impacts that are moderate and reasonable. The Department also finds the high voltage metering discounts satisfy continuity goals and are reasonable. The Department finds that the Company's proposed method for establishing the on-peak volumetric charge for Rate G-3, subject to our findings on the MMRC, satisfies simplicity goal, as well as our continuity goal, and produces bill impacts that are moderate and reasonable, considering the size of the increase. 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 Company is directed to set the monthly customer charge at $223.00, the demand charge at $7.60 and to set its on-peak volumetric charges to collect the balance of the class revenue requirement approved in this Order, truncated at five decimal places.

7. Street Lighting

a. Introduction

National Grid 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; (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; (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-HSG-1, at 31). The Company proposed the following: (1) to update the street lighting temporary turn-off charge; (2) a new design for the per-kWh rate for the S-5 rate class; and (3) to update its light-emitting diode ("LED") luminaries options (Exhs. NG-HSG-1, at 32-33; NG-HSG-Rebuttal-1, at 4).

b. Company Proposal

The Company proposes to increase Rates S-1, S-2, S-3 (Option A), S-3 (Option B), and S-6 by approximately 15 percent (Exhs. NG-HSG-1, at 31; NG-HSG-6, at 7-10). The Company proposes a temporary turn-off rate equal to 61.8 percent of the full service charge (Exhs. NG-HSG-1, at 32; NG-HSG-6, at 7, 11). Additionally, the Company is proposing a decrease to Rate S-5 to include costs only that would continue to be incurred when the Company does not own, operate, or maintain the luminaires and supports (Exhs. NG-HSG-1, at 33; NG-HSG-2C-3, NG-HSG-6, at 7). All street lighting revenue is recovered without the use of customer or demand charges (Exh. NG-HSG-6, at 7-11).

Moreover, in the Company's last base distribution rate case proceeding, National Grid included rates in its streetlight tariffs for a number of LED luminaries that were determined based on estimated kWh sales (Exh. DPU-NG 21-13). In this proceeding, the Company is proposing to update the tariff to reflect more efficient luminaries that it installed on the system since the Company's last base distribution rate case (Exh. NG-HSG-1, at 32).

c. Positions of the Parties

i. Attorney General

The Attorney General opposes the Company's actions regarding the LED street lighting tariff (Attorney General Brief at 111-112). The Attorney General claims that the Company should be ordered to adopt new procedures for, and pay refunds to, certain LED street lighting customers (Attorney General Brief at 117). The Attorney General asserts that the Company has included in its tariff types of luminaries that were never installed and that the Company has proposed updates to its tariffs for LED street lighting service to reflect the types of LED luminaries that are actually installed and have been in service since 2017 (Attorney General Brief at 117, citing Tr. 10, at 1349-1350). The Attorney General contends that the LED luminaries in service since at least 2017, which are unmetered and charged based on standard assumptions of operation, were more energy efficient than the luminaries in the tariff (Attorney General Brief at 117, citing Tr. 10, at 1353). The Attorney General argues that, because customers were charged based on the tariff, the Company has knowingly overcharged these customers since the time the LED luminaries were installed (Attorney General Brief at 117-118, citing Exh. NG-HSG-13; Tr. 10, at 1352-1353). The Attorney General argues that the Department should direct the Company to refund the difference in energy charges to all customers paying for LED streetlights (Attorney General Brief at 118). The Attorney General also argues that the Department should require the Company to prospectively file a tariff modification within 30 days of the date it begins installing LED luminaries that are more energy efficient than those listed in its tariff (Attorney General Brief at 119).

ii. DOER

DOER states that the Company did not initially propose any provisions in its tariff to allow customer controls to reduce energy consumption by streetlights (DOER Brief at 45). DOER notes that, upon request, the Company provided a revised S-5 tariff that would allow for the operation of luminaires for any number of hours and at any light output desired (DOER Brief at 45, citing Exhs. DOER-NG 2-2; DOER-NG 2-2(b)). DOER requests that the Department order the Company to adopt the revisions in its Rate S-5 tariff, as set forth in Exhibit DOER-NG 2-2 (DOER Brief at 45).

iii. Company

Regarding the LED lighting tariff, the Company states that it billed customers according to the approved Rate S-1 tariff (Company Brief at 489, citing Tr. 10, at 1352-1353). The Company claims that, in order to bill for the more efficient LED street lights installed, the Company would have had to file a base distribution rate case as provided in G.L. c. 164, § 94, and subsequently change the tariff rates (Company Brief at 489). The Company argues that such an exercise would likely cost more than the savings in energy charges that related to the installation of the more efficient equipment (Company Brief at 489, citing RR-AG-30). The Company also argues that the Department has generally viewed single-issue rate cases unfavorably and only warranted in narrow circumstances (Company Brief at 489-490). The Company claims that, because the discrepancy in energy charges did not necessitate a single-issue rate case, the Company is correct in addressing the tariff adjustments in the current proceeding (Company Brief at 490).

Regarding the Attorney General's position that the Department should require a prospective tariff modification for all new LED luminaires, the Company reiterates that such a change typically necessitates a full base distribution rate case, resulting in higher costs to customers that would outstrip the difference in energy charges (Company Reply Brief at 165). Additionally, the Company argues that requiring the tariffs to keep pace with rapidly changing LED technology would cause rate instability, confusion, and overall customer frustration (Company Reply Brief at 166-167, citing Tr. 10, at 1351). Furthermore, the Company claims that, if this principle were taken to its extreme, the Company would be able to update any of its tariffs to account for technological or other advances (Company Brief at 490-491). The Company contends that these types of updates would be disruptive to customers and would be contrary to the Department's goals of rate continuity and stability (Company Brief at 491).

The Company states that it is proposing a new design for the per-kWh rate for the Rate S-5 (Company Brief at 470, citing Exh. NG-HSG-1, at 33). The Company claims that its newly developed Rate S-5 allocates costs between those incurred regardless of who owns the street lighting equipment and costs that would be avoided if the Company did not own the equipment (Company Brief at 470). Separate from the new design of the Rate S-5, the Company addresses DOER's recommendation regarding the Rate S-5 tariff. The Company notes that, as stated at the May 10, 2019 evidentiary hearing, the Company would adopt the revised tariffs if ordered to do so by the Department (Company Brief at 491, citing Tr. 10, at 1364). Additionally, the Company proposes to update the charges for temporary turn-off service for street lights to an amount equal to 61.8 percent of the full-service charge (Company Brief at 469, citing Exh. NG-HSG-1, at 32). The Company states that this percentage represents the revenue necessary to recover return on investment, depreciation expense, property taxes, and income taxes on streetlight facilities (Company Brief at 469).

d. Analysis and Findings

In the Company's last base distribution rate case, National Grid included rates in its streetlight tariffs for a number of LED luminaries that were determined based on estimated kWh sales (Exh. DPU-NG 21-13). Before the stated LED luminaries were put into service on the Company's system, more efficient luminaries became available (Exh. DPU-NG 21-13). These more efficient LED luminaires were installed beginning in 2017 and customers were charged according to the tariff, which calculated energy usage based on the older LEDs that were listed in the tariff and had higher energy usage (Exhs. DPU-NG 21-13; AG-SJR-Surrebuttal-1, at 6). In this proceeding, the Company is proposing to update the tariff to reflect the more efficient luminaries that were installed on the system (Exh. NG-HSG-1, at 32).

The Attorney General claims that street-lighting customers were overcharged because their bills were calculated using the annual kWh-per-luminaire of LED luminaires that were not actually installed (Attorney General Brief at 118-119). Under G.L. c. 164, § 94, an electric company is required to file with the Department schedules showing all rates, prices, and charges to be thereafter charged and collected within the Commonwealth for the sale and distribution of electricity. With limited exception, no different rate, price, or charge shall be charged, received, or collected.[293] The Supreme Judicial Court has found that the Department is thus authorized to "inquire into whether the rates, prices, and charges, charged

[293] General Laws c. 164, § 94, allows limited exceptions (1) where a company submits revised schedules and the Department finds it is in the public interest after notice and public hearing, and (2) for special contracts.

or collected, for the sale and distribution by an electric company have conformed to the schedules filed with that agency." 352 Mass. 18, 26-27. The Department has reviewed the current tariff M.D.P.U. No. 1363 and the record evidence and finds that the Company charged rates, prices, and charges to customers for services that did not match the authorized descriptions listed on its tariff (Exh. DPU-NG 21-13; Tr. 10, at 1350). As such, the Company was in violation of G.L. c. 164, § 94. Therefore, the Department directs the Company to return the difference in energy charges to customers based on the difference between the kWh consumption of the luminaires actually installed and those listed in the existing tariff. The Department directs the Company to provide to the Department within six weeks of the date of this Order its proposal for the customer refunds. In future cases where more efficient LED luminaires become available for implementation, the Company is directed to submit a revision of its tariff to include such luminaires before customers are billed for their use. The Department finds that such a revision would not necessitate a base distribution rate case as the cause for the tariff change would be not constitute a general increase in rates (Tr. 10, at 1352-1353). G.L. c. 164, § 94; 438 Mass. 256, 268. The Department further notes that a tariff revision would be necessary in this case because customers' bills are explicitly calculated using the details of their luminaires, rather than the technological improvements in and of themselves.

In response to an information request from DOER, the Company provided a revised S-5 tariff that allows street-lighting customers to reduce their electricity usage (Exh. DOER-NG 2-2, Att.). The Company is willing to adopt the revised tariff if so ordered by the Department (Tr. 10, at 1364). The Department concludes that the revised tariff is reasonable and finds that it expands customers' capacity for energy efficiency. The Department, therefore, orders the Company to adopt the S-5 tariff, as shown in Exhibit DOER-NG 2-2, in its compliance filing.

The Company proposed a temporary turn-off service charge of 61.8 percent of the full service charge for street-lighting customers (Exh. NG-HSG-1, at 32). No party has raised concerns regarding this issue on brief. The Department finds that the Company's proposal is reasonable and, as such, we allow the temporary turn-off charge as proposed.

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. 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.

XVII. LOW-INCOME FUEL ASSISTANCE ISSUES

A. Introduction

MEDA is an association of agencies throughout the Commonwealth that administer fuel assistance benefits to eligible low-income households. According to MEDA, fuel assistance agencies receive thousands of applications from households across the state, review and process those applications in accordance with rules set by the Massachusetts Department of Housing and Community Development, and make payments on a household's energy bills (with the exception of a small fraction of the households, who instead receive payments towards their rent) (Exh. MEDA-DG at 2). As part of the fuel assistance process, agencies communicate directly with National Grid through various means, including electronically transmitting client information, accessing the Company's billing system, and speaking by telephone or communicating via e-mail with customer service representatives and other Company employees (Exh. MEDA-DG at 2). In the instant proceeding, in order to facilitate the fuel assistance agencies in their efforts, MEDA requests changes to several of National Grid's protocols for how the agencies and the Company communicate with each other and share data (Exh. MEDA-DG at 3).

B. MEDA Requests/Company Responses

1. FTP System Log-In Credentials

MEDA states that fuel assistance agencies transfer information to and from National Grid through the Company's file transfer protocol ("FTP") system, to which they gain access by using a log-in identification and password (Exh. MEDA-DG at 4; see also Exh. MEDA-DG-1). MEDA contends that the Company provides each fuel assistance agency with the same log-in credentials, so if one agency inadvertently enters the incorrect log-in information, all agencies in the Company's service territory are locked out of the FTP system (Exh. MEDA-DG at 4-5). According to MEDA, lockouts are frequent and they hinder an agency's ability to promptly make payments on behalf of fuel assistance customers or to otherwise assist customers (Exh. MEDA-DG at 5). MEDA argues that the Company, during the course of the instant proceeding, acknowledged that it had initiated the process of providing unique log-in credentials for each fuel assistance agency (MEDA Brief at 5-6, citing Tr. 6, at 823; RR-MEDA-1). MEDA requests that the Department direct the Company to either (1) attest in writing that it already has provided unique log-in credentials to the various fuel assistance agencies or (2) require the Company to provide such credentials within 30 days of this Order (MEDA Brief at 6; MEDA Reply Brief at 5-6). National Grid states that it is working on address the FTP lock-out issue and to create unique log-in credentials for each fuel assistance agency (Company Reply Brief at 167, citing RR-MEDA-1).[294]

2. Determining Low-Income Discount Status

According to MEDA, one of the most important services that fuel assistance agencies provide is ensuring that customers are appropriately placed on the Company's low-income discount rate (Exh. MEDA-DG at 10). MEDA states that when accessing the Company's billing system, fuel assistance agencies cannot make this determination for electric customers; however, fuel assistance agencies can make this determination for natural gas customers of the Company's affiliates, Boston Gas and Colonial Gas (Exh. MEDA-DG at 10, citing Exh. MEDA-DG-9). MEDA contends that during the proceedings, the Company

294 On May 7, 2019, in response to record request MEDA-1, the Company estimated that it would take one-month to create the unique log-in credentials (RR-MEDA-1). It appears that the work was not completed in one month, however, as the Company noted in its reply brief, which was filed on July 25, 2019, that it was continuing to work on MEDA's request (Company Reply Brief at 167).

acknowledged that it has initiated changes to its billing system to correct this inconsistency (MEDA Brief at 8, citing Tr. 6, at 825). MEDA requests that the Department either (1) direct the Company to attest in writing that the billing system upgrades have been completed or (2) require the Company to complete the necessary upgrades within 30 days of this Order (MEDA Brief at 8; MEDA Reply Brief at 7).

National Grid asserts that it completed a billing system change so that fuel assistance agencies now can see an electric customer's rate status (Company Reply Brief at 169-170). The Company claims that it communicated this change to the fuel assistance agencies on July 15, 2019 (Company Reply Brief at 170).

3. Billing System Search Criteria

MEDA states that fuel assistance agencies routinely need to access the Company's billing system to determine how much a customer owes the Company and for which time periods, and to determine a customer's kWh usage (Exhs. MEDA-DG at 8). To access the billing system for these purposes, the fuel assistance agencies must enter the customer's account number or Social Security number, while Company employees can access an account simply by entering a customer's name and address (Exhs. MEDA-DG at 9; MEDA-DG-6; MEDA-DG-7). MEDA contends that during the proceedings the Company expressed a willingness to provide the agencies with easier access to the billing system (MEDA Brief at 9-10, citing Tr. 3, at 369; MEDA Reply Brief at 7). Thus, MEDA requests that the Department direct the Company to "work cooperatively" with MEDA to develop a protocol for providing the fuel assistance agencies with such easier access (MEDA Brief at 9-10; MEDA Reply Brief at 7).

The Company states that, after further investigation, it cannot easily provide fuel assistance agencies with the ability to search for a customer by name and address (Company Reply Brief at 170). According to National Grid, the fuel assistance agencies use a portal to extract information from the Company's billing system, and the portal is designed to search using a method that provides the account based on an exact match of the data used in the search (i.e., account number or Social Security number) (Company Reply Brief at 170). The Company claims that it cannot easily manipulate the search functionality of the portal to accommodate various methods of searching by names or addresses (e.g., full spelling, abbreviations) (Company Reply Brief at 170).

4. Retroactive Placement – Low-Income Discount

According to MEDA, Boston Gas and Colonial Gas are able to retroactively place a fuel assistance gas customer on the low-income discount rate, regardless of when during the fuel assistance season the customer applied and was determined to be eligible for the discounted rate (Exh. MEDA-DG at 6). MEDA contends that during the proceedings, the Company agreed that the same billing system functionality would be beneficial to low-income electric customers, but noted that the billing system would require upgrades to accommodate this change (MEDA Brief at 7, citing Tr. 3, at 366-367; RR-MEDA-2). MEDA requests that the Department order the Company to add such functionality to its billing system, or to set a date by which National Grid will provide a report, with a cost estimate, of the process necessary to enable the Company to make such upgrades (MEDA Brief at 7-8; MEDA Reply Brief at 6).

National Grid states that, after further investigation it is not feasible for the Company to automate a retroactive transfer process to satisfy MEDA's requests (Company Reply Brief at 168). National Grid notes under its current billing system, any activity on electric customer accounts beyond simple billing will cause the automated retroactive transfer process to fail, thereby requiring the Company to manually correct the account over the number of months over which the customer is retroactively placed on the rate class (Company Reply Brief at 168-169, citing RR-MEDA-2, at 1). Further, National Grid claims that before it could provide a cost estimate and timeline regarding any billing system changes, the Company would need to spend considerable time thoroughly reviewing its billing system and developing the business requirements, functional requirements, and the scope of the coding necessary to make any changes (Company Reply Brief at 168, citing RR-MEDA-2, at 1).

Moreover, the Company asserts that its current process for placing newly qualified electric customers on the low-income discount rate is reasonable (Company Reply Brief at 169). According to the Company, as soon as it receives notice of a newly qualified low-income discount electric customer, it places the customer on the discounted rate (Company Reply Brief at 169, citing Exh. MEDA-DG-3; RR-MEDA-2, at 1). The customer then continues on the discounted rate for 18 months, which allows the customer additional time to recertify for public benefits and remain qualified for the low-income discount rate (Company Reply Brief at 169, citing Exh. MEDA-DG-3; RR-MEDA-2, at 1). The Company asserts that the additional time on the low-income discount rate compensates a customer for not being retroactively transferred to November 1 in the year that the customer was first placed on the rate, and it also serves to avoid a gap in service and any lost discount during the recertification process (Company Reply Brief at 169, citing Exh. MEDA-DG-3; RR-MEDA-2, at 1). Further, the Company claims that its current process allows a qualifying customer to remain on the low-income discount rate for a longer period of time than any gap they would experience between November 1 and the date they qualified for the reduced rate (Company Reply Brief at 169).

5. Notice of Expositions

MEDA notes that the Company holds consumer expositions, usually in the fall and spring of each year (Exh. MEDA-DG at 11). According to MEDA, at these expositions, National Grid provides customers with access to Company personnel who can discuss the availability of fuel assistance, discounted rates, and arrearage management programs (Exh. MEDA-DG at 11). To ensure that fuel assistance agencies and customers are aware of such expositions, MEDA requests that the Company provide the agencies with sufficient advance notice and work with the agencies to jointly select a mutually convenient date and time (Exhs. MEDA-DG at 11).

National Grid states that it contacts multiple social service agencies in the community when scheduling consumer expositions, including the fuel assistance agency servicing the area where the exposition is held (Exh. MEDA-DG-10). Further, the Company claims that it coordinates with the various agencies on the availability of facilities and representation at the planned events, which typically are held in the fall to spring season to inform customers that the fuel assistance agencies are open and are taking applications (Exh. MEDA-DG-10).

C. Analysis and Findings

As noted above, MEDA raises five issues for the Department's consideration. First, MEDA requests that National Grid provide each fuel assistance agency with unique log-in credentials for accessing the Company's FTP system (MEDA Brief at 6; MEDA Reply Brief at 5-6). Based on the Company's response, the Department expects that this request has been satisfied (see RR-MEDA-1 & n.294, above). The Department directs National Grid, as part of its compliance filing, to verify that the Company has provided unique log-in credentials to each fuel assistance agency for purposes of accessing the FTP system.[295]

Second, MEDA requests that National Grid upgrade its billing system so that fuel assistance agencies can determine whether an electric customer is on the low-income discount rate (MEDA Brief at 8; MEDA Reply Brief at 7). On brief, the Company asserts that it completed the requested billing system change and communicated the change to the fuel assistance agencies on July 15, 2019 (Company Reply Brief at 170). The Department directs the Company, as part of its compliance filing, to verify that such change was made and the manner in which the change was communicated to each fuel assistance agency.

Third, MEDA requests that the Department direct National Grid to work to provide fuel assistance agencies with easier access to the Company's billing system (e.g., accessing a

[295] Alternatively, if MEDA's request has not been satisfied, the Company, in its compliance filing, shall provide a detailed explanation of its efforts and a date certain by which it expects to complete the work.

customer's account by entering the customer's name or address, as opposed to using an account number or Social Security number) (MEDA Brief at 9-10; MEDA Reply Brief at 7). The Company, after further investigation, claims that it cannot easily upgrade the search functionality of the particular customer portal used by fuel assistance agencies to allow for searching by names or addresses (Company Reply Brief at 170). The Department recognizes the benefits of prompt, easy access to a customer's account, and we encourage the Company to continue to work with the fuel assistance agencies to achieve these objectives. Nonetheless, we find that the requirement for fuel assistance agencies to enter an account number or Social Security number to access a customer account is neither unreasonable nor overly burdensome. Although Company employees are able to access a customer's account by name or address (Exh. MEDA-DG-7), we are not persuaded that MEDA has presented a compelling reason for National Grid to undertake a potentially time consuming and costly upgrade of its billing system to allow fuel assistance agencies similar or expanded search criteria for billing system access (see Exh. MEDA-DG-8). Accordingly, we decline to issue any directives in this regard.

Fourth, MEDA requests that National Grid upgrade its billing system so that the Company is able to place a fuel assistance electric customer on the low-income discount rate retroactive to November 1, regardless of when the customer applied and was determined to be eligible for the discounted rate (MEDA Brief at 7-8; MEDA Reply Brief at 6). National Grid argues that it would take a significant effort simply to ascertain the time and cost involved in such an upgrade and that a reasonable alternative already exists for eligible electric customers (Company Reply Brief at 168-169, citing Exh. MEDA-DG-3; RR-MEDA-2, at 1).

As an initial matter, we find that Boston Gas's and Colonial Gas's practice of placing a gas customer on the low-income discount rate retroactive to November 1 is reasonable, as that date coincides with the beginning of the heating season for natural gas service (RR-MEDA-2, at 1). Further, the Department will not second guess the Company's determination regarding the resources necessary to investigate whether such changes to the billing system to achieve retroactive placement for electric customers are feasible (RR-MEDA-2, at 1). Moreover, the Company's practice of allowing qualified electric customers to continue on the discounted rate for 18 months is a reasonable alternative to retroactively transferring the customer to November 1 (Exh. MEDA-DG-3; RR-MEDA-2, at 1). Based on these considerations, we are not persuaded that MEDA has presented a compelling reason for the Company to undertake a potentially time consuming and costly upgrade of its billing system to allow for electric customers to be retroactively placed on the low-income discount rate. Accordingly, we decline to issue any directives in this regard.

Finally, MEDA requests that National Grid provide the fuel assistance agencies with sufficient advance notice of customer expositions and to work with the agencies to jointly select a mutually convenient date and time (Exh. MEDA-DG at 11). The record shows that National Grid's outreach efforts include direct contact with the fuel assistance agencies regarding the seasonal scheduling of expositions, availability of host facilities, and Company representation at these events (Exh. MEDA-DG-10). The Department finds that the

Company's outreach efforts are appropriate, and we expect that the Company will continue to make every reasonable effort to inform the fuel assistance agencies of the details of any future expositions. We find it unnecessary to issue any additional directives in this regard.

XVIII. 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	443,606,181	(7,035,598)	(5,326,251)	431,244,332
Depreciation & Amortization	154,780,438	(2,167,245)	(5,102,452)	147,510,741
Taxes Other Than Income Taxes	85,138,028	(6,745,750)	(171,882)	78,220,396
Interest on Customer Deposits	231,212	0	0	231,212
Income Taxes	33,028,005	3,281,686	835,170	37,144,861
Return on Rate Base	178,129,160	237,540	(15,714,769)	162,651,932
Additional Uncollectibles (Revenue Deficiency)	1,783,391	(219,610)	(348,331)	1,215,450
Total Cost of Service	896,696,415	(12,648,976)	(25,828,514)	858,218,924
OPERATING REVENUES				
Base Distribution Revenues	732,179,995	0	0	732,179,995
Other Operating Revenues	32,290,464	3,623,904	0	35,914,368
Total Operating Revenues	764,470,459	3,623,904	0	768,094,363
Total Revenue Deficiency	**132,225,956**	**(16,272,880)**	**(25,828,514)**	90,124,561

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	1,282,560,623	0	0	1,282,560,623
Normalizing Adjustments	(870,579,794)	246,756	0	(870,333,038)
Test Year O&M Expense	411,980,829	246,756	0	412,227,585
ADJUSTMENTS TO O&M EXPENSE:				
Labor	18,033,851	(2,024,044)	(245,134)	15,764,673
Health Care	449,812	2,304	0	452,116
Group Life Insurance	190,010	(21,382)	(1,364)	167,264
Thrift Plan	780,040	(87,778)	(5,603)	686,659
FAS 112 / ASC 712	0	0	0	0
Service Company Rents	(3,676,175)	(2,152,159)	148,703	(5,679,631)
Joint Facilities	0	0	(57,396)	(57,396)
Uninsured Claims	0	0	0	0
Insurance Premium	119,659	0	0	119,659
Regulatory Assessment Fees	0	(1,269,247)	0	(1,269,247)
Uncollectible Accounts	0	0	0	0
Postage	381,503	(217,430)	0	164,073
Environmental Response Fund	0	0	0	0
Purchased Power-Borderline Sale	0	0	0	0
Paperless Bill Credit	0	0	0	0
PBOP	0	0	0	0
Pension	0	0	0	0
Energy Efficiency Program	0	0	0	0
Other Operating and Maintenance Expenses	(3,060,560)	8,999	(2,062,076)	(5,113,637)
MECO NEP IFA	(1,236,962)	92,283	0	(1,144,679)
Wheeling	0	0	0	0
Storm Fund	8,800,000	0	(3,300,000)	5,500,000
Major Storm Deductible Adjustment	0	0	200,000	200,000
O&M Inflation Adjustment	10,553,389	(1,525,021)	(3,381)	9,024,987
Environmental Response Fund Inflation Adjustment	290,785	(88,879)	0	201,906
Sum of O&M Expense Adjustments	31,625,352	(7,282,354)	(5,326,251)	19,016,747
Total O&M Expense	**443,606,181**	**(7,035,598)**	**(5,326,251)**	**431,244,332**

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:	$408,002,288
Less Company Adjustment:	
Labor	$143,942,046
Health care	$18,869,382
Group Life & Other Insurance	$1,516,444
Thrift Plan	$6,225,377
Service Company Rents	$31,388,845
Insurance Premiums	$4,899,087
Regulatory Assessment Fees	$8,081,372
Uncollectible Accounts	$22,619,239
Postage	$6,076,801
Purchase Power-Borderline Sale	$2,429,942
Paperless Bill Credit	$1,449,838
Other Operating and Maintenance Expenses	$10,246,665
Transmission IFA Billing to NEP	($19,494,514)
Storm Fund	$10,500,000
Major Storm Deductible	$6,000,000
Total O&M Adjustments	$254,750,524
Residual O&M Expenses Subject to Inflation per Company	$153,251,764
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:	5.89%
Inflation Allowance per Company	$9,028,368
Environmental Response Fund	$4,225,296
Projected Environmental Response Fund rate	4.78%
Inflation Allowance for Environmental Response	$201,906
Less: Department Adjustments	
Company Adjustments	$254,750,524
Joint Facilities	($57,396)
Department Sub-total	$254,693,128
Residual O&M Expense Subject to Inflation	$153,194,368
Inflation Factor from Midpoint of Test Year to Midpoint of Rate Year:	5.89%
Inflation Allowance per DPU	$9,024,987
Reduction to Cost of Service	$3,381

D. Schedule 3 - Depreciation and Amortization Expenses

	PER COMPANY	COMPANY ADJUSTMENT	DPU ADJUSTMENT	PER ORDER
Depreciation & Amortization	144,087,329	(2,549,801)	(5,102,452)	136,435,076
SAP Enhancements	0	305,325	0	305,325
Farm Discount	85,941	0	0	85,941
Gain on Sale of Property	(158,292)	0	0	(158,292)
Hardship Protected Accounts	10,284,545	0	0	10,284,545
Normalized Rate Case Expense	480,915	77,231	0	558,146
Total Depreciation and Amortization Expense	154,780,438	(2,167,245)	(5,102,452)	147,510,741

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	4,589,337,281	5,160,659	(40,154,080)	4,554,343,860
LESS:				
Reserve for Depreciation and Amort.	(1,797,431,624)	(4,110,438)	(18,438,183)	(1,819,980,245)
Net Utility Plant in Service	2,791,905,657	1,050,221	(58,592,263)	2,734,363,615
ADDITIONS TO PLANT:				
Cash Working Capital	71,370,644	(1,364,419)	165,637	70,171,861
Other Materials and Supplies	24,926,145	0	0	24,926,145
Prepayments	1,445,404	643,151	(2,088,555)	0
Total Additions to Plant	97,742,193	(721,268)	(1,922,918)	95,098,006
DEDUCTIONS FROM PLANT:				
Reserve for Deferred Income Tax	(393,104,739)	(468,372)	0	(393,573,111)
Estimated Excess Deferred Taxes	(248,462,560)	3,093,901	(6,495,539)	(251,864,198)
Customer Construction Advances	(6,255,608)	0	0	(6,255,608)
Customer Deposits	(26,288,121)	0	0	(26,288,121)
Total Deductions from Plant	(674,111,028)	2,625,529	(6,495,539)	(677,981,038)
RATE BASE	2,215,536,822	2,954,482	(67,010,720)	2,151,480,583
COST OF CAPITAL	8.04%	8.04%	-0.48%	7.56%
RETURN ON RATE BASE	**178,129,160**	**237,540**	**(15,714,769)**	**162,651,932**

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	$1,300,000,000	46.43%	5.22%	2.42%
Preferred Stock	$2,259,000	0.08%	4.44%	0.00%
Common Equity	$1,497,850,000	53.49%	10.50%	5.62%
Total Capital	$2,800,109,000	100.00%		8.04%
Weighted Cost of				
Debt				2.42%
Preferred				0.00%
Equity				5.62%
Cost of Capital				8.04%

COMPANY ADJUSTMENTS	PRINCIPAL	PERCENTAGE	COST	RATE OF RETURN
Long-Term Debt	$1,300,000,000	46.43%	5.22%	2.42%
Preferred Stock	$2,259,000	0.08%	4.44%	0.00%
Common Equity	$1,497,850,000	53.49%	10.50%	5.62%
Total Capital	$2,800,109,000	100.00%		8.04%
Weighted Cost of				
Debt				2.42%
Preferred				0.00%
Equity				5.62%
Cost of Capital				8.04%

PER ORDER	PRINCIPAL	PERCENTAGE	COST	RETURN
Long-Term Debt	$1,300,000,000	46.43%	5.22%	2.42%
Preferred Stock	$2,259,000	0.08%	4.44%	0.00%
Common Equity	$1,497,850,000	53.49%	9.60%	5.14%
Total Capital	$2,800,109,000	100.00%		7.56%
Weighted Cost of				
Debt				2.42%
Preferred				0.00%
Equity				5.14%
Cost of Capital				7.56%

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	4,649,155	0	0	4,649,155
Total O&M	443,606,181	(7,035,597)	(5,326,251)	431,244,333
Transmission	493,548,641	0	0	493,548,641
Uncollectible Accounts - Unadjusted TY	22,619,239	0	0	22,619,239
Paperless Bill Credit	1,449,838	0	0	1,449,838
Taxes Other than Income	127,647,424	(5,442,131)	(171,882)	122,033,411
	1,045,382,324	(12,477,728)	(5,498,133)	1,027,406,463
Cash Working Capital Factor	6.83%	10.93%	6.83%	6.83%
Cash Working Capital Allowance	71,370,644	(1,364,419)	165,637	70,171,861

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	65,015,253	0	0	65,015,253
Payroll Tax	12,554,642	0	0	12,554,642
Other Taxes	(266,972)	0	0	(266,972)
	77,302,923	0	0	77,302,923
ADJUSTMENTS TO TAXES OTHER THAN INCOME:				
Normalizing adjustments:				
Municipal Tax	0	0	0	0
Payroll Tax	(946,992)	0	0	(946,992)
Other Taxes	1,652,139	(1,171,565)	0	480,574
Known & measurable adjustments:				
Municipal Tax	6,243,478	(5,442,130)	(165,927)	635,421
Payroll Tax	793,010	(50,227)	(5,955)	736,828
Other Taxes	93,470	(81,828)	0	11,642
Total Adjustments	7,835,105	(6,745,750)	(171,882)	917,473
Totals				
Municipal Tax	71,258,731	(5,442,130)	(165,927)	65,650,674
Payroll Tax	12,400,660	(50,227)	(5,955)	12,344,478
Other Taxes	1,478,637	(1,253,393)	0	225,244
Taxes Other Than Income	85,138,028	(6,745,750)	(171,882)	78,220,396

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	2,215,536,822	2,954,482	(67,010,720)	2,151,480,583
Return on Rate Base	178,129,160	237,540	(15,714,769)	162,651,932
Interest Expense	53,615,991	71,498	(1,621,659)	52,065,830
Amortization of Net Excess Deferred Tax	6,797,006	(2,339,767)	(4,457,239)	0
Amortization of ITC	484,935	0	0	484,935
Income Tax Impact of Flowthrough Items	2,345,610	0	0	2,345,610
Amortiz. of Net Unfunded Deferred Tax Liability	384,693	0	0	384,693
Total Deductions	63,628,235	(2,268,269)	(6,078,898)	55,281,068
Taxable Income Base	114,500,925	2,505,809	(9,635,870)	107,370,864
Gross Up Factor	1.3759	1.3759	1.3759	1.3759
Taxable Income	157,541,176	3,447,728	(13,257,939)	147,730,965
State Franchise Tax 8%	12,603,294	275,818	(1,060,635)	11,818,477
Federal Taxable Income	144,937,882	3,171,910	(12,197,304)	135,912,488
Federal Income Tax at 21%	30,436,955	666,101	(2,561,434)	28,541,622
Amortization of Net Excess Deferred Tax	(6,797,006)	2,339,767	4,457,239	0
Amortization of ITC	(484,935)	0	0	(484,935)
Income Tax Impact of Flowthrough Items	(2,345,610)	0	0	(2,345,610)
Amortization of Net Unfunded Deferred Tax Liab	(384,693)	0	0	(384,693)
Total Income Taxes	**33,028,005**	**3,281,686**	**835,170**	**37,144,861**

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	732,179,995	0	0	732,179,995
Other Operating Revenues	30,852,474	3,824,309	0	34,676,783
Known & Measurable Adj. to Other Operating Revenue				
Rent from Electric Property	0	486,221	0	486,221
Miscellaneous Service Revenue	(374,464)	(12)	0	(374,476)
Construction Reimbursement	1,812,454	(686,614)	0	1,125,840
	1,437,990	(200,405)	0	1,237,585
Adjusted Total Operating Revenues	764,470,459	3,623,904	0	768,094,363

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 – Allocation to Rate Classes

Department Approved Revenue Increase $90,124,561

Rate Class	COSS Target Revenue (1)	Company Proposal Current Distribution Revenue (2)	Deficiency at EROR (3)	Percent Increase at EROR (4)	Per Order Deficiency at EROR (5)	Total Revenue Based on Current Rates (6)	Per Order Dist. Revenue Percent Increase at EROR (7)	Section 20 Revenue Increase Cap (8)	Excess Increase to be Re-allocated (9)	Re-allocation to Uncapped Rate Classes (10)	Uncapped and Re-allocated Per Order Revenue Increase (11)	Per Order Revenue to be Re-allocated 200% Cap (12)	Per Order Re-allocation to Uncapped Rate Classes (13)	Per Order Revenue Requirement (14)	Per Order Revenue Increase (15)
Residential R-1/R-2/R-4	$480,570,282	$412,935,041	$67,635,241	16.38%	$46,095,323	$1,967,874,615	11.16%	$196,787,462	0	$2,588,296	$48,683,619	$0	$0	$461,618,660	$48,683,619
Small C&I G-1	$107,824,217	$91,470,901	$16,353,317	17.88%	$11,145,246	$444,762,697	12.18%	$44,476,270	0	$578,613	$11,723,859	$0	$0	$103,194,760	$11,723,859
Medium C&I G-2	$100,649,016	$85,863,136	$14,785,880	17.22%	$10,076,994	$504,510,186	11.74%	$50,451,019	0	$540,970	$10,617,963	$0	$0	$96,481,099	$10,617,963
Large C&I G-3	$147,112,995	$125,915,662	$21,197,333	16.83%	$14,446,580	$1,133,862,265	11.47%	$113,386,227	0	$791,449	$15,238,029	$0	$0	$141,153,691	$15,238,029
Streetlight	$28,262,423	$15,995,260	$12,267,163	76.69%	$ 8,360,418	$38,610,906	52.27%	$3,861,091	4,499,327	$0	$ 3,861,091	$0	$0	$19,856,350	$3,861,091
Total Company	$864,418,933	$732,180,000	$132,238,933	18.06%	$90,124,561	$4,089,620,670	12.31%	$408,962,067	$4,499,327	$4,499,327	$90,124,561	$0	$0	$822,304,561	$90,124,561
					$90,124,561										

FOR ILLUSTRATIVE PURPOSES ONLY

Notes:

(1) Exhibit NG-HSG-4, Line 23
(2) Exhibit NG-HSG-4, Line 2
(3) Exhibit NG-HSG-4, Line 29, also Column (1) - Column (2)
(4) Column (3) ÷ Column (2)
(5) Total Revenue Deficiency per Schd 1 * (Column (3)/Column (3)Total)
(6) Exhibit NG-HSG-4, Line 31
(7) Column (6) ÷ Column (2)
(8) Column (6) x 10%
(9) If Column (8) > Column (5), then $0. If Column (8) < Column (5), then Column (5) - Column (8)
(10) [(Column (2) + Column(5) for applicable rate class) ÷ (sum of Column (2) + Column (5) for uncapped rate classes)] x Total Column (9)
(11) Column (6) - Column (9) + Column (10)
(12) If [Column (11) ÷ Column (2)] > 2 x [Total of Column (6)], then Column (11) - [Column (2) x (2 * Total Column (6)]. If not, then zero.
(13) [(Column (2) + Column(5) for applicable rate class) ÷ (sum of Column (2) + Column (5) for uncapped rate classes)] x Total Column (12)
(14) Column (2) + Column (11) - Column (12) + Column (13)
(15) Column (14) + Column (2)

XIX. ORDER

Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the tariffs M.D.P.U. Nos. 1373 through 1383 filed by Massachusetts Electric Company on November 15, 2018, to become effective December 1, 2018, are DISALLOWED; and it is

FURTHER ORDERED: That the tariffs M.D.P.U. Nos. 610 through 620 filed by Nantucket Electric Company on November 15, 2018, to become effective December 1, 2018, are DISALLOWED; and it is

FURTHER ORDERED: That the tariffs M.D.P.U. Nos. 1384 through 1401 filed by Massachusetts Electric Company and Nantucket Electric Company on November 15, 2018, to become effective December 1, 2018, 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 increase annual electric revenues by $90,124,561; 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 shall apply to electricity consumed on or after October 1, 2019, but, unless otherwise ordered by the Department, shall not become effective earlier than seven days after the rates are filed with supporting data demonstrating that such rates comply with this Order.

By Order of the Department,

/s/
Matthew H. Nelson, Chair

/s/
Robert E. Hayden, Commissioner

/s/
Cecile M. Fraser, Commissioner

An appeal as to matters of law from any final decision, order or ruling of the Commission may be taken to the Supreme Judicial Court by an aggrieved party in interest by the filing of a written petition praying that the Order of the Commission be modified or set aside in whole or in part. Such petition for appeal shall be filed with the Secretary of the Commission within twenty days after the date of service of the decision, order or ruling of the Commission, or within such further time as the Commission may allow upon request filed prior to the expiration of the twenty days after the date of service of said decision, order or ruling. Within ten days after such petition has been filed, the appealing party shall enter the appeal in the Supreme Judicial Court sitting in Suffolk County by filing a copy thereof with the Clerk of said Court. G.L. c. 25, § 5.